



SINGLE ELECTRICITY MARKET COMMITTEE

Integrated Single Electricity Market (I-SEM)

Summary of Responses to Draft Decision Paper on I-SEM High Level Design (SEM-14-045)

SEM-14-085c

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'The SEM Committee is established in Ireland and Northern Ireland by virtue of section 8A of the Electricity Regulation Act 1999 and Article 6 (1) of the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 respectively. The SEM Committee is a Committee of both CER and NIAUR (together the Regulatory Authorities) that, on behalf of the Regulatory Authorities, takes any decision as to the exercise of a relevant function of CER or NIAUR in relation to an SEM matter.'

1 INTRODUCTION

The SEM Committee wishes to thank market participants and other stakeholders for their efforts in responding to the Draft Decision and in participating in the public Stakeholder Forum in June 2014. Active stakeholder engagement is an important part of delivering the I-SEM in a way that delivers the greatest benefits for the all-island market.

This paper provides a summary of the responses received in relation to the Draft Decision Paper on the I-SEM High Level Design (HLD) (SEM-14-045). The SEM Committee also sets out its position on the issues highlighted in the responses. This follows careful consideration of the extensive set of responses received to the Draft Decision Paper as well as further technical analysis by the Market Integration Project Team. The SEM Committee received 98 responses (plus 2 supporting reports) to the Draft Decision Paper, 5 of which were confidential. The SEM Committee has published the non-confidential responses on the All-Island Project website.¹ The Annex 1 lists all of the non-confidential responses received to the Draft Decision Paper. It also illustrates that 40 respondents stated support for the submission of the Irish Wind Farmers Association (IWFA), and 15 stated support for the submission by the Irish Wind Energy Association (IWEA).

A number of respondents referenced the level of detail available in the draft decision proposals and pointed to the considerable number of decisions that will need to be taken at the detailed design phase. This was the case on energy trading arrangements, and on the form of the CRM. In some areas, such as the balancing market and imbalance settlement, this reflects that the level of detail set at EU level is less than the DAM and IDM for example.

The SEM Committee agrees that many detailed design decisions must be made in the detailed design and implementation phase of the I-SEM project. The creation of the I-SEM rules is inevitably a step-by-step process, and compromises must be struck between outlining the high level points and defining detail. If the SEM Committee was to progress too far into detail before the high level points are agreed, there is a risk that the consultation on the high-level issues would be compromised, as respondents might devote undue attention to the issues which are of secondary importance.

The resolution of detailed issues requires strong interaction with the market stakeholders, including the market operator and TSO. In work that has been carried out to date in support of the HLD decision, the Market Integration Project Team has sought to think through the detailed issues far enough to be sure that workable solutions for detailed design are available, but without foreclosing the detailed design work. The SEM Committee has sought to strike a balance between detailed and high level design and looks forward to working closely with the industry as the Market Integration Project moves into the detailed design phase.

¹ http://www.allislandproject.org/en/wholesale_overview.aspx?article=79e244a0-4c06-4729-bd20-92873869df82&mode=author

A significant number of respondents to the Draft Decision paper raised concerns around the mitigation of market power in the I-SEM and in particular pointed to a lack of detail on how this might be achieved. In addition, some respondents suggested that the SEM Committee in its draft decision paper may have suggested that market power concerns are not as significant as they once are.

The SEM Committee wishes to reiterate its commitment to the implementation of an effective market power mitigation strategy covering all aspects of the market, including energy and capacity. Market power mitigation was a key issue in the Memorandum of Understanding which commenced work on All Island arrangements for energy in the last decade and continues to be a significant consideration now.

The SEM Committee will consider the most appropriate market power mitigation strategy as part of the detailed design and implementation phase. Within this, a dedicated workstream will be set up for market power. This approach is consistent with the approach taken as part of the design of SEM in 2005 where the High Level Design was developed first and the market power mitigation strategy followed as part of implementation.

1.1 STRUCTURE OF THE DOCUMENT

The document is structured as follows:

- Chapter 2 summarises the issues raised in responses in relation to the proposed HLD of Energy Trading Arrangements in the I-SEM;
- Chapter 3 addresses the proposed decision to retain a Capacity Remuneration Mechanism (CRM) in the I-SEM;
- Chapter 4 summarises responses on the form of the proposed HLD for the CRM in the I-SEM;
- Chapter 5 highlights issues raised in responses on the lessons learnt from the SEM, and on the HLD process to date, including the Initial Impact Assessment (IIA); and
- Chapter 6 summarises the issues raised in relation to the process going forward for the detailed design and implementation of the I-SEM.

The annexes contain supporting material on:

- list of respondents (Annex 1);
- International Experience of aggregator of last resort type arrangements (Annex 2),
- the operation of demand, and special units in the EUPHEMIA algorithm in the European day-ahead market (Annex 3); and
- the market power mitigation measures included in the Capacity Remuneration Mechanism (CRM) which is being introduced in the electricity market in Great Britain (Annex 4).

2 ENERGY TRADING ARRANGEMENTS

This chapter provides a summary of the responses received in regard to the proposed HLD of the Energy Trading Arrangements (ETA) for the I-SEM. It is structured in line with the main elements of the proposed decision set out in the Draft Decision Paper on the I-SEM HLD (SEM-14-045):

- Forward trading;
- Day-Ahead Market (DAM);
- Intraday Market (IDM);
- Balancing Market (BM); and
- Imbalance arrangements.

Each of these sections starts with a reminder of the draft decision before summarising the responses by issue. Each section then concludes with a statement of the SEM Committee position on each issue raised by respondents

2.1 FORWARD TRADING

2.1.1 DRAFT DECISION

The Draft Decision Paper set out the following decisions in regard to forward trading:

- The I-SEM will have only financial trading instruments for within zone trading.
- Subject to further discussions and agreement with other neighbouring markets, Cross-Zonal trading will be supported only by Financial Transmission Rights (FTRs).

2.1.2 SUMMARY OF RESPONSES

Forward Market Liquidity

A number of respondents noted the importance of liquid and efficient forward markets. These help suppliers to efficiently hedge, provide stable retail prices and facilitate competition, helping to mitigate market power and providing investment signals.

One respondent stated that a Forward Market Maker Obligation should be placed on vertically integrated participants, given the characteristics of the Irish market.

Financial versus Physical Contracting in the Forwards Timeframe

One key distinction in the forwards timeframe is whether physical or financial contracts or both are employed/permitted. The majority of respondents favor the restriction of forward trading to financial contracts only as per the Draft Decision Paper but the Viridian Group remains opposed.

There was significant support from respondents for financial trading in the forward timescales. Reasons given for this included the fact that it would enable market participants to hedge out price risks over longer timeframes without removing liquidity from the Day Ahead (DAM) and Intraday (IDM) market timeframes. Respondents also stated that financial forward trading allows for the most efficient flows on the Interconnector.

A specific issue raised by some large energy customers was that they are not permitted to use financial instruments. Therefore only allowing the purchase of electricity on the forward market through financial instruments would limit the opportunity for their participation in the market.

Other respondents discussed the complexity that would arise from the interaction between financial forward energy trades and the proposed Reliability Options. Some respondents also stated that the interaction between the forward market and the Reliability Options would require a centrally planned approach to be ready in time for the start of the ISEM. This was because standard two-way hedging forwards contracts cannot be used without taking into account the impact of the Reliability Options.

Scheduling risk

One of the objections to limiting forward trading to being financial only was the impact on the ability of a generator to manage scheduling risk under the EUPHEMIA algorithm. Respondents who raised this point stated that mid-merit thermal assets have the most material exposure to scheduling risk.

Use of FTRs

Respondents raised concerns about the introduction of FTRs, particularly in advance of FTRs becoming widespread in Europe. One respondent noted that it would be counterintuitive to adopt FTRs when the majority of Europe is focused on harmonising Physical Transmission Rights (PTRs). One respondent stated that PTRs should not reduce the amount of physical cross-zonal capacity available for implicit allocation, and with firm prices at the Day-Ahead and Intraday stages, they should 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 the use of PTRs does not improve, then FTRs can be introduced at a later stage. Another respondent stated that FTRs should result in the same practical outcome as PTRs with use it or sell it (UIOSI) requirements.

Some respondents stated that physical cross-border trading would help efficient cross border flows, which would ultimately lead to lower scheduling risk in the market. One of these respondents went on to state that the SEM Committee was confused about the difference between efficient arbitrage and efficient use. This respondent stated that this was illustrated by the statement in the Draft Decision paper that FTRs best achieve the objectives of integration. However, the efficient use of the interconnector also relies on the outcomes of the Intraday Market and TSO adjustments.

Allowing the possibility of tracking physical flows will be integral to the cross border trade of renewable certificates and possible future capacity products according to one respondent. This approach currently exists on a number of interconnectors with a respondent citing their experience of how this works on the BritNed interconnector. One respondent also noted that with cross border trade of renewable power and certificates increasing across Europe, the Regulatory Authorities would be naïve to embrace one trend of European energy policy (e.g. price coupling) to the exclusion of other trends in European markets (e.g. cross border renewable trade and linked capacity markets).

Another respondent stated that making the transition from PTRs to FTRs immediately from I-SEM go-live is a high risk approach, and therefore PTRs should be facilitated at least until the market is established. This respondent also stated that if FTRs are to be introduced, they should be in the form of FTR options rather than FTR obligations.

A respondent also had the view that the Draft Decision paper had overestimated the ease of which FTRs could be implemented, while at the same time overstating the difficulty in continuing with PTRs.

A couple of respondents highlighted the interaction with the GB market and requested clarity on engagement with Ofgem and reiterated that the RAs would need to ensure coordination with the GB market if the I-SEM was to switch from PTRs to FTRs.

Another respondent highlighted the importance of the final European requirements in relation to firmness, and the impact on the risk borne by interconnector owners.

2.1.3 SEM COMMITTEE RESPONSE

Forward Market Liquidity

The SEM Committee recognises the importance of a liquid and transparent forward market as part of the successful implementation of the I-SEM. The SEM Committee agrees that forward markets are important for allowing suppliers to hedge volume and price risks efficiently and competitively to meet the tariff needs of customers, as well as delivering greater competition in generation through providing a route to market and predictable revenue streams. It also recognises that there are lessons to be learnt from the SEM that a liquid spot market will not on its own guarantee forward market liquidity.

Therefore, the SEM Committee has set out in its Decision on the HLD of the I-SEM that it will consider and pursue specific measures to promote forward liquidity. Such is the importance of this issue, there will be a dedicated workstream on the forwards market and liquidity as part of the detail design and implementation phase. As part of this, the SEM Committee will look to international experience including recent developments in GB and the highly liquid forward markets in the Nordic region. The form and scope of these measures, including for example any market maker requirements on some or all participants, will be discussed with industry as part of the detailed design phase.

Financial versus Physical Contracting in the Forwards Timeframe

Specific concerns have been expressed by some large energy customers about their ability to trade contracts that are deemed to be financial in nature. In the context of the I-SEM, a financial forward contract means that any contracts struck between market participants in the forwards timeframe will not confer a right to physically schedule generation, demand or cross-zonal capacity in the all-island market.

In that regard the I-SEM will be no different from the arrangements currently in place in the SEM today, where all forward contracts are financial Contracts For Difference (CFDs) settled against the reference price from the gross mandatory pool. Therefore, this aspect of the I-SEM would not introduce a new barrier to forward trading compared to the current situation.

Concerns have been expressed by respondents about the interaction between forward energy trading and the ROs. The SEM Committee has addressed this issue in detail in Section 4.2.3 below.

Scheduling risk

A number of respondents raised concerns about the ability of market participants to manage scheduling risk. This was supported by the inclusion in a number of responses of a multi-client consultant report from Baringa on the issue of “scheduling risk” in the I-SEM. The consultant report describes scheduling risk as occurring when a generator, *“bidding at cost, will not be scheduled, even if the DAM price is higher. In this scenario a generator that had hedged forward would be exposed to the market price, at a loss relative to its SRMC”*. Of the four respondents who commissioned the Baringa report, only one is in favour of a self-scheduling approach in the I-SEM which they argue would mitigate scheduling risk. The other three respondents who commissioned the report are not in favour of a self-scheduling approach.

Given the weight placed on the scheduling risk issue by some market participants, this point is addressed in detail. The SEM Committee here explains how the scheduling risk is not a specific feature of the proposed I-SEM HLD but rather reflects a general challenge for electricity markets.

The Unit Commitment Problem

At the heart of the issues raised around scheduling risk is the unit commitment problem faced in determining the least-cost dispatch of available generation resources to meet load. The key decisions are how many generation units to start up, and, once on, at what level of output they should generate in each period. The unit commitment process must take into account the physical realities such as non-linear cost functions, and intertemporal issues – for example, minimum up and minimum down times, and ramp rates.

This is a problem associated with electricity markets in general and is not an issue that can

be solved by the choice between central or self-scheduling. In the All-Island Market, the unit commitment process is further complicated by a relatively peaky within-day demand profile, relatively large unit sizes and high levels of variable renewable generation.

Within this unit commitment problem, baseload plant generally don't have a problem with commitment in that they are generally committed and scheduled to run at a steady output level throughout the day. Peaker plants tend to have low start up costs and can come on at short notice to meet increased demand. The key issue, as noted in the consultant report, is the difficulty in committing mid merit plants. These plants tend to have a level of start-up costs and technical characteristics, such as long minimum up and down times, that are not conducive to being started up and shut down quickly. They tend to be 'lumpy' plants operating close to the margin. Therefore the main difficulty in the unit commitment problem is committing and scheduling these mid merit units across the day in an efficient manner to meet changing demand.

A sub-optimal result in unit commitment can result in an over commitment of mid merit units or, inversely, an under commitment of mid merit units combined with a corresponding increased reliance on peakers to start up and meet variations in demand at the margin throughout the day. A successful solution to the unit commitment problem will result in mid merit units operating between the two extremes though, in reality, success is difficult to define precisely, as ultimately there is no guarantee of a unique price profile that would deliver exactly the quantities required in each settlement period. Given this, the EUPHEMIA concept of "paradoxically rejected" offers describes this physical reality, and is not a result of a flaw in the algorithm.

Unit Commitment in the All-Island Market

In 2012 the TSOs produced a report for the SEM Committee which looked at dispatch models². Section 5 of that report contained a useful comparison of the physical characteristics of the SEM and GB systems. One statistic highlighted in the report was that system size in GB is around 10 times that of SEM, even though the typical unit size in both systems is quite similar. This suggests that the commitment of units to meet load in SEM is inherently more difficult given the relationship between unit size and the load to be met. Therefore, regardless of decisions around self versus central scheduling the unit commitment problem is one that sits underneath all the choices available in terms of market design.

² http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=41f5681a-ef37-41ca-ab7d-7a1bdd7db385

The difficulty of the unit commitment problem in the All-Island Market is exacerbated even further by the magnitude of start-up costs. Stoft suggests that start-up costs in the US are usually found in the range between \$20/MW and \$40/MW.³ In the All-Island Market, start-up costs for a CCGT are currently circa €250/MW for the most part. This difference contributes to the issue of scheduling risk and again, this issue will not be eliminated by self-scheduling.

Central versus Self Scheduling

Following the identification of the unit commitment problem, and its importance in the All-Island Market, the most pertinent issue then becomes how it can be best dealt with through the design of the I-SEM and how to achieve the most efficient unit commitment for all plants, not just an individual plants or participants.

The SEM currently deals with this issue through a power pool type arrangement where generators submit three part cost reflective commercial offers consisting of start-up costs, no-load costs and price quantity pairs. The SEM Unconstrained Unit Commitment (UUC) algorithm then centrally commits plants to meet the load throughout the day at least cost based on these three-part offers. The marginal price quantity pair sets the Shadow Price in each trading period. Any start-up costs and no-load costs not recovered by plants through infra-marginal rents from the Shadow Price over a contiguous operating period are recovered through uplift. Uplift is a separate component which is added to the Shadow Price to form the System Marginal Price which should ensure no plants run at a loss in the market.

The approach to unit commitment in the I-SEM set out in the SEM Committee Draft Decision has many similarities to the current market. It is based on a centralised scheduling process albeit with different bid and offer structures. Essentially, at the day-ahead stage, generators and load submit offers to sell and bids to purchase respectively to a local power exchange, which are then passed onto the central European Day-Ahead Market algorithm, EUPHEMIA. EUPHEMIA seeks to match load with generation across the day to maximise total social welfare. There is a single market clearing price for each hourly trading period.

As referred to in the Draft Decision, Stephen Stoft sets out in his book on electricity market design 'Power System Economics'⁴³ that it is possible for power exchanges using two part bids to perform unit commitment as well as power pools and that side payments are not required to remove DAM 'volume' risk to generators. The key point is that a day-ahead market run by a centralised power exchange can be used to solve unit commitment through market participants internalising start-up costs. While some generators may have difficulty doing this through simple bids, as Stoft notes 'a slight complication in power exchange bidding can help generators solve the unit commitment problem'. This slight complication

³ Power System Economics – Designing Markets for Electricity– Stephen Stoft, Wiley 2002

that Stoft refers to is given effect to in the EUPHEMIA algorithm through the suite of more complex products that it currently supports beyond simple bids and offers i.e. block bids, linked bids etc.

High penetration of variable renewable generation may make it more difficult for market participants to predict when, and at what output, mid merit plants will be required to produce. This may lead to greater variation in the production profiles of mid-merit plants from day to day. This is because the requirement for mid-merit production will be driven not only by demand profiles, which are reasonably predictable on a long-term basis, but also by wind patterns.

However, market participants will be submitting bids into the DAM on a daily basis. At that stage, they will have a much better view of the likely profile of the net demand for thermal generation than in forward timescales. In addition, the DA schedule will be solved on the basis of the bids submitted by all parties at the same time - the DA gate closure. Therefore, in the DA schedule itself, market participants are not exposed to timing issues resulting from forecast errors or changes in forecast after the submission of the day-ahead bids. These issues can be addressed in the IDM.

Centralised scheduling processes are designed to deliver a socially optimal production schedule based on the granularity of bids and offers received. Therefore, any centralised scheduling process must address the issues around the incentives for efficient revelation of cost structures through bids.

An example was provided by respondents where spreading no load costs over several Child Blocks in a Linked Block Order allowed a unit to avoid an overnight shutdown. However, it also increased the risk of under-recovery of production costs versus the case where all no load costs were included in the Parent Block. As the DAM will take the form of a repeated game, a market participant would have to balance the risks with any potential gains to be made from submissions which deviate from its best simple reflection of its underlying cost structure.

Market participants would have the same incentive issues with respect to the bidding of start-up costs in the current SEM arrangements. In the SEM generators are not incentivised to submit low start-up costs as if they do they are more likely to be cycled as the algorithm sees them as cheap to restart. Some generators currently include costs associated with the risk of cycling in their start-up costs. This helps them to avoid the risks of cycling while also being compensated in the market for taking those risks.

An alternative to a centralised scheduling process is self-scheduling – this is an arrangement where a generator and supplier execute physical deals outside of the centralised market at an agreed price. This physical deals may be done internally for a vertically integrated participant, or through bilateral or OTC trading. The market participants proceed to nominate the outcome of those deals to the TSO in the form of physical nominations.

The SEM Committee has previously given significant consideration to the matter of scheduling risk in the Market Integration Project. The Easter Bay Report⁴, commissioned by the SEM Committee in 2012, discussed the matter in detail. In particular, Easter Bay stated;

It does appear that some consultation respondents who favoured self-dispatch in their submissions have not favoured it for reasons associated with the Target Model. They appear to have different motivations, based on a desire for increased firmness in their bilateral transactions. However physical firmness (a guarantee that X MW can be moved from A to B) cannot be guaranteed under either self-dispatch or central dispatch. Physical deliverability is a function of the physical system, and not of the trading model used.

Therefore, because the decision as to whether their nomination could be accepted depended on system conditions, Easter Bay stated that those favouring self-dispatch were actually seeking financial firmness of their nominated position. In their report, Easter Bay further stated:

Financial firmness is financially equivalent to physical firmness (and therefore has the same value as physical firmness) and is available under either self-dispatch or central dispatch. Under self-dispatch, however, implementation of side-payments would be necessary to ensure financial firmness and this could increase market costs.

Side payments would be required because some generators would have to be moved away from their nominated physical positions so that the system could be operated securely. Side payments would ideally be limited to the cost of moving from a least-cost but unconstrained schedule, to a least-cost actual dispatch taking into account system constraints, which would be the case under centralised commitment and dispatch. However it would be difficult, if not impossible, to limit the cost to this level under self-dispatch because neither the starting unconstrained schedule nor the final actual dispatch could be guaranteed to be least-cost.

Given the above, it would appear that the respondent in question's preference for self-scheduling in the context of the I-SEM is based on a desire for an ex-ante level of financial firmness for plants that have self-scheduled. It is germane to examine therefore who ultimately gains from self-scheduling. It would appear that it is the parties who are either vertically integrated or bilaterally contracted can benefit in the first instance which likely makes the situation for non-vertically integrated participants more difficult by impairing the instruments that they currently have to manage their risks. Easter Bay concurred with this view, arguing that central commitment and dispatch was more efficient because, unlike self-scheduling, there was no restriction of information (which could, for example, result in a more expensive generator being dispatched because it was not known that a cheaper one was available) or asymmetry of information (e.g. larger participants having better price information than smaller participants).

⁴ The Easter Bay "Review of TSO Report on the Dispatch Model for the All Island Market/Transmission System (SEM-12-105c) should be read in conjunction with this Response Paper

It was following these considerations in 2012 and 2013 that the SEM Committee made the following decisions in the Next Steps Decision Paper:

The SEM Committee's Decision is that there will be a working assumption:

- That the SEM high level design will continue to be based on transparent centralised trading arrangements, least-cost dispatch of total system load and centralised unit commitment. It will not rely on a process whereby market participants are required to enter into matched physical bilateral contracts and where there are financial penalties imposed for not doing so.
- Options for self-commitment may be permitted within this high level design, taking into account the particular characteristics of the electricity sector on the island of Ireland, including the need to mitigate market power.
- There will continue to be market power mitigation measures in the SEM for as long as market power is considered to be an issue.

The SEM Committee again considered options for a market model based on greater use of self-commitment as part of the I-SEM HLD consultation process in 2014.

A minority of respondents have suggested that allowing self-scheduling based on physical forward trades between generators and suppliers is an appropriate response to managing this scheduling risk. Under a physical forward contract that would allow self-scheduling, the generator takes on an obligation to provide the agreed amount of energy over the agreed timescales. The SEM Committee does not agree with this as a means of facilitating an optimal outcome for I-SEM market participants.

One possible solution that has been proposed in the consultation in relation to the scheduling risk is that mid-merit generators would effectively become a price-taker to ensure that they are scheduled in line with their forward contracts.

Such bidding is generally not a desirable or sustainable outcome from a system perspective as it reduces the amount of price-responsive generation in the market. It is also not desirable from an individual generator perspective.

Indeed, Viridian stated in their response that in a self-dispatch bilateral contract market a generator with a forward physical contract position, acting rationally, has a strong economic incentive to submit a bid to buy to the DAM at a price below their SRMC in order to maximise profits on forward sales.

Longer-term forward contracts in electricity markets are most commonly traded on a baseload basis only. Where peak contracts are traded, then this is generally only from the year-ahead stage. A mid-merit generator simply wanting to secure its baseload forward physical margin will miss out on the opportunities to increase profit by trading in the DAM and IDM. Trading in these markets allows the generator to move from a baseload production profile to a sculpted production profile that reflects the needs of the system, as represented in the price profile. For example, the mid-merit generator may be able to meet

its forward contract requirements overnight by buying from the market at a lower price than its own production costs.

The respondent also stated that this could be mandated by introducing an Economic Purchase Obligation (EPO) on all generators by means of a licence condition. Such an EPO would mandate the bidding of all physical bilateral contract positions held by generators into the DAM at or below SRMC.

This would facilitate the buying back of physical forward contract positions from the DAM and essentially deliver a centrally traded market with physical forward contracting and self-scheduling.

To access the trading opportunities to sculpt its production profile, the generator will therefore have to participate in the DAM, and IDM. At that stage, a mid-merit plant with a physical forward contract would face many of the same issues discussed in relation to scheduling risk with financial contracts – primarily how to structure a bid to buy energy back when the timing and volume is uncertain. Such a generator would need the same type of bid and offer formats that a party with a forward financial contract would be looking for

While the introduction of an EPO in a bilateral physical forward contract market would seem to have merit, the issue of scheduling risk would still be present.

A generator without a forward physical contract could submit an offer to sell to the DAM with a price that is lower than a contracted generator's bid to buy back, lower than the market clearing price, but not be scheduled due to the Order being paradoxically rejected (this is discussed in further detail later). Therefore this would not mitigate the risk that would be placed on non-vertically integrated generators.

Ultimately the SEM Committee has not seen evidence that a move to a self-commitment market would provide a better overall solution for the All-Island market than the centralised scheduling and commitment approach proposed for the I-SEM.

Therefore, the SEM Committee has taken the decision that the all-island market will continue to be based on centralised unit commitment, scheduling and trading mechanisms in order to deliver the best outcomes for consumers. Centralised scheduling processes are designed to deliver a socially optimal result based on the bids and offers received.

The SEM Committee accepts that there will continue to be a need to address issues such as scheduling risk in the detailed design phase. This includes ensuring that there is maximum availability, to the extent technically possible, of different order types that allow market participants to best reflect the characteristics of their units. These mechanisms are seen as managing complex and non-convex generation cost structures, in a liquid and transparent manner. Indeed the importance placed on transparency is one way of addressing the information asymmetries for portfolio players raised in responses by parties supporting self-scheduling.

The SEM Committee welcomes the efforts of market participants to better understand the opportunities and challenges represented by the different order formats available in EUPHEMIA. This will help market participants to better understand how individual technical characteristics, such as ramp rates, can be reflected in all but the most simple orders into EUPHEMIA. This allows market participants to manage the risk of receiving a technically infeasible schedule from their individual perspective. This will place more responsibility on generators to internalise their own cost calculations in their offers as part of their trading and risk management strategies.

Further detailed testing of EUPHEMIA will be undertaken to ensure that the maximum possible flexibility is available to market participants in terms of order structures to the extent that it is feasible and cost-effective. As acknowledged by respondents, the issue of scheduling risk arises even in a pool with fully complex three part offers.

The optimal implementation of the DAM, IDM and BM will also be important in this regard as will the development of a well-functioning forwards market.

For example, good quality real-time information on system conditions and accurate, competitive, cost-reflective imbalance prices will be of high importance in managing the issue of scheduling risk in the I-SEM.

In some markets, there is no requirement for unit-based bidding into a centralised scheduling process. However, many of the respondents who raised the scheduling risk issue were concerned about portfolio benefits. Therefore, they would not see portfolio bidding as a viable route to addressing this issue. The SEM Committee agrees with these respondents on this point.

A robust and liquid intraday market will help to mitigate scheduling risk by reflecting the fact that the delivery of efficient dispatch, including use of the interconnectors, will be the result of trading over a number of different market timeframes, as well as TSO actions.

Respondents identified that bids into the Balancing Mechanism will be affected by the scheduled starting positions for the next day – i.e. that a bid to be dispatched down would need to take into account the need to recover costs of then restarting to meet the scheduled profile. In that case, the extra start-up cost reflects a real physical cost that should be incorporated in the bid into the Balancing Market. The SEM Committee also notes that a market participant has the opportunity to fine-tune its position for the next day in the intraday market after the release of the day-ahead schedule.

Some respondents highlighted a concern that the scheduling risk would mean that market participants would be exposed to making repayments under the RO even when their production costs were below the strike price. The SEM Committee has set out above in detail its views on the scheduling risk issue in general. With particular reference to the RO the operation of the CRM and its interaction with the energy trading arrangements will be taken forward in the detailed design phase of the project. The level of the strike price will be important in determining the materiality of any scheduling risk in that regard.

Use of PTRs

Responses in favour of the use of PTRs in the I-SEM cited four main reasons:

- the familiarity and widespread use of PTRs in the SEM and in European markets;
- the ability to self-schedule and manage one's own physical position;
- the link to the physical transfer of electricity that is included in some cross-border trading mechanisms – e.g renewable certificates; and
- Implementation issues.

The SEM Committee set out in significant detail in the Draft Decision Paper why PTRs are being recommended as the preferred form of cross border transmission right. This should be referred to in conjunction with the response paper.

The concern about the efficiency of PTRs is not one of nominated flows being in the uneconomic direction as the implicit coupling processes can address this by reversing the flow. Rather, the issue is about the interconnector capacity helping to increase liquidity and competitive pressures in the DAM and IDM, such that it can help to mitigate market power issues that may arise on a stand-alone island basis. This problem is worsened where the interconnector flow nominations are actually in the economic direction. That is when the interconnection capacity is most valuable to provide competitive pressures in the intraday market.

Therefore, the issue around the use of PTRs is not based on an assumption that they will be used inefficiently; rather the problems arise when the nominations are efficient in terms of the direction of flow being in line with prices.

The sections below in turn deal with the arguments put forward for PTRs by respondents.

PTRs and Physical Self-Scheduling

For the I-SEM, the review of the form of the explicit transmission rights is precipitated by the change in the HLD and also by the expected implementation of the Forwards Capacity Allocation Commission Guideline. The implementation of PTRs in the current SEM is done in a very particular way in the current design to adapt the concept of physical rights to the mandatory SEM pool. Nomination of PTRs currently does not confer any right to physical nomination. Instead it confers exclusive rights on active capacity holders to bid in the EA1 SEM Gate. Use It Or Sell It (UIOSI) then takes effect after the EA1 Gate and all interconnector users can bid in the EA2 Gate regardless of whether they hold any interconnector capacity.

This would not be the case under the EU Target Model with a move to PTR nomination with UIOSI, which occurs before the DAM. Within the centralised arrangements in I-SEM, if a market participant nominates to import or export under a PTR, this would only be of value if it can be matched by a physical nomination for demand and/or generation. However, in I-SEM, the restriction on physical forward trading means that the PTR holders would not have

an opportunity to nominate against their transmission right, which would effectively collapse to an FTR.

PTRs with UIOSI are equivalent to FTRs when not nominated – however, the issue is that any perceived benefits for rights holders of allowing nominations must be balanced against the risks of possibly undermining the efficiency of the overall market. This reflects that it is important to understand how the long-term transmission rights affect the efficiency of the market over all timeframes, as well as their efficacy when used to hedge the risk of cross-border forward trading.

For example, scheduling interconnector flows based on efficient arbitrage in ex-ante timeframes is important in the cross-border integration of electricity markets over the whole range of timeframes. To support this efficient arbitrage process, the EU Target Model is based around the expiry of explicit transmission rights at the day-ahead stage. This means that the form of explicit transmission rights has a particularly important impact on the efficiency and competitiveness of the arbitrage process in the day-ahead markets.

Of course, it is to be expected that the Day-Ahead scheduled interconnector flows based on efficient arbitrage may differ from the out-turn flows for an efficient use of the interconnector in real time. However, efficient arbitrage at the Day-Ahead stage is a good starting point for the scheduling of the flows. One of the advantages of the EU Target Model is that the coupling of intraday and ultimately the integration of balancing markets means that scheduled flows at any point should best reflect the market information available at the time. Therefore, FTRs are much more compatible than PTRs with the overall HLD of the I-SEM ETA which is based on exclusive centralised near term markets and are entirely consistent with the provisions of the EU Target Model and its implementation.

Use of PTRs across Europe

The provisions of the EU Target Model reflect the current situation in Europe where there are a range of cross-zonal risk hedging products in use. This includes PTRs and FTRs as well as financial products not issued by TSOs, such as EPAD in Nordpool, which have been in place since 2000.

Looking forward, one of the aims of the EU Target Model is to harmonise the procedures for initial allocation and secondary allocation of cross-zonal transmission rights. These procedures will have to reflect the range of cross-zonal rights in use today and available under the EU Target Model. This is confirmed by the wording in section 4.1 of the CACM Framework Guidelines that requires a single platform for the allocation of long-term transmission rights (both PTR and FTR) at a European level.

Therefore, the harmonisation of allocation procedures provides no particular advantage for PTRs. Harmonised nomination rules should not be confused with harmonised allocation rules – the former is relevant for PTRs only, whereas the allocation rules would apply equally to PTRs and FTRs.

The ACER wish list on forward risk hedging products⁵ set out that the initial priority was to harmonise allocation rules and develop a single auction platform, before then choosing the form of forward hedging products. Therefore, as part of the implementation of the EU Target Model, other markets may well review their existing arrangements in relation to long-term transmission rights. It is worth noting that on this point, the possible implementation of FTRs is the fourth element of the European cross-regional roadmap on long-term transmission rights. Furthermore, the ACER wish list specifically notes the potential evolution from PTRs with UIOSI to FTR options. The wish list was informed by responses received from a range of European market participants.

It is not therefore accurate to describe the Target Model as moving towards a harmonisation around PTRs. The widespread use of PTRs typically reflects the fact that the arrangements were put in place before the implementation of day-ahead coupling in many European markets.

Given that the Target Model allows PTRs or FTRs, it is important to understand the context in which the SEM Committee is expressing its preference for FTRs as part of the HLD of the I-SEM. It is also helpful to consider this in the context of European reports on long-term capacity rights for cross-border trade. This includes a report by a group of independent consultants and academics commissioned and procured by the European Commission Directorate General for Energy⁶, the ACER Wish List for Long-Term Transmission Rights and the 2011 ACER Cross Regional Roadmap for long term transmission rights which envisaged the elaboration of a pan-European implementation plan to move to FTRs⁷.

The DG Energy consultancy report states that the most important precondition for the implementation of FTRs is the establishment of effective Day-Ahead price coupling. This is consistent with the comment in the ACER wishlist that respondents found the ability to nominate against PTRs helpful where the Day-Ahead market is illiquid. Indeed, the most liquid day-ahead markets in Europe are in NordPool which uses financial rather than physical cross-border products. The DG Energy consultancy report notes that with highly liquid DAMs, the trading incentive is generally not to nominate against a PTR. This is also on the condition of efficient imbalance prices and day-ahead market participation fees that are not too significant, particularly for smaller traders. The SEM Committee agrees that effective day-ahead coupling arrangements are required for the successful implementation of FTRs but this does not require a single set of governance arrangements for all of the markets involved, as suggested by one respondent.

⁵ 'ACER Public Consultation on Forward Risk Hedging Products & Harmonisation of Long Term Capacity Allocation rules Evaluation of responses and final ACER "wish-list" for further harmonisation of auction rules for Long-Term Transmission Rights. ACER. February 2013

⁶ 'Physical and Financial Capacity Rights for Cross-Border Trade. Final Report R01071. Prepared for Directorate-General Energy European Commission', Booz & Co. September 2011., Professor David Newbery, University of Cambridge, Professor Goran Strbac, Imperial College, London September 2011.
http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2012_transmission.pdf

⁷ http://www.acer.europa.eu/Electricity/Regional_initiatives/Cross_Regional_Roadmaps/Pages/3.-Long-Term-Transmission-Rights.aspx

The SEM Committee committed to ensuring effective price coupling of the DAM with the rest of the EU internal market from I-SEM Go-Live and that the DAM provides highly liquid and robust reference prices. Furthermore, it is noteworthy that there has been a significant increase in DA liquidity in the neighbouring BETTA market in GB in recent years. By the time the I-SEM is launched, the DA market coupling arrangements will have been in operation for much of Europe for over two years. This includes the countries closest to the I-SEM. Therefore, the I-SEM will not rely on a new set of day-ahead coupling arrangements with no track record in order to value FTRs.

At this stage, a preference for FTR Obligations or Options has not been stated. This will be considered further during the detailed design phase as well as the approval process for auction rules and forward capacity allocation as set out in the draft Forward Capacity Allocation Guideline. The detailed design phase will consider the issues raised by respondents to date in relation to the ability to net FTR Obligations and the resulting credit implications.

The Cross Border Trading of Certificates

In some cases, requirements around the physical transfer of electricity are placed to allow the cross-border trading of renewable certificates. This issue of the form of transmission rights and their facilitation of cross-border trading of green energy was also raised in a response to the consultation on the ACER wishlist. It is also recognised that the definition of physical delivery remains an important point of discussion in the debate around ensuring cross-border access to CRMs.

The view of the SEM Committee is that any such issues are not sufficient to justify the adoption of PTRs, when weighed against the compatibility of the FTRs with the overall HLD of the I-SEM energy trading arrangements.

Ultimately, under the Target Model, a market participant cannot guarantee the physical flow of an interconnector in a particular direction, even through the nomination of a PTR. This is because the implicit allocation of capacity through price-coupling takes over from the DA stage onwards, which can reverse any nominated levels. Therefore, FTRs will not have a negative impact on the tradeability of Guarantee Of Origin Certificates, etc. compared to PTRs. Once this is accepted as it will have to be for cross-border trading of any renewable or capacity certificates after the implementation of the EU Target Model, then it does not seem a major step to facilitate cross-border participation without physical nomination of a cross-zonal flow.

Implementation of FTRs

As FTRs are much more compatible with the overall HLD of the I-SEM ETA, a reliance on PTRs at the start may actually hinder the introduction of the new HLD, rather than being a low-risk measure as suggested by some respondents

The Guideline on Forward Capacity Allocation will specify the process that has to be followed in determining the nature of long-term transmission rights. This includes the need for cross-border cooperation between national regulatory authorities (NRAs). The SEM Committee has already begun the process discussion with Ofgem on this issue and further consultation will take place on this matter as part of the detailed design phase under the aegis of the Forward Capacity Allocation Guideline.

The SEM Committee acknowledges the importance of the final European requirements in relation to firmness risk, as highlighted by respondents. The Long Term Firmness Deadline (LTFD) will determine the point at which full financial firmness is conferred on holders of a capacity right. The LTFD concept is applicable for both PTRs and FTRs, and will ultimately ensure that both types of right provide equal firmness to holders, and the flipside of exposure to firmness for interconnector owners and/or the consumers who underwrite them. It would not therefore be correct to prefer PTRs to address the suggested risk of 'regulatory dogma' at European level leading to more onerous firmness regimes for FTRs than PTRs.

Concerns have been expressed surrounding the treatment of FTRs under MIFID and EMIR. In 2012 ACER and ENTSO-E recommended to the European Commission when drafting the MIFID II regulation that PTRs and FTRs be exempted insofar as possible⁸. MIFID II contains an exemption for regulated entities issuing products subject to regulatory control. However, the MIFID II exemptions for PTRs and FTRs only concerns the primary allocation and not the secondary trading where market players could fall under the jurisdiction of MIFID II requirements. This means that the primary allocation of transmission rights do not fall under the scope of MIFID, but would instead be covered by REMIT, which are arrangements specifically in place for the energy sector. The SEM Committee will continue to monitor developments in this area as part of the detailed design phase, and where appropriate engage with the relevant authorities.

2.2 DAY-AHEAD MARKET

2.2.1 DRAFT DECISION

The Draft Decision Paper set out the following decisions in regard to the Day-Ahead Market:

- The European Day Ahead Market will be the 'exclusive' route to a physical contract nomination.
- There will be unit-based participation for generation in general, with (gross portfolio) aggregation arrangements for DSU, demand and (some) variable renewable generation.

2.2.2 SUMMARY OF RESPONSES

⁸http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Recommendations/ACER%20Recommendation%2001-2012.pdf

The main points raised by respondents discussing the DAM were in relation to establishing whether participation in the DAM should be exclusive or mandatory; and, establishing whether EUPHEMIA was fit for purpose. Other comments related to the over-emphasis on the DAM to the detriment of other timeframes and overall efficiency.

Exclusive vs. Mandatory DAM

There was a range of views espoused among respondents in regard to the 'exclusiveness' of the Day-Ahead market. The decision to make the Day-Ahead Market Exclusive rather than Mandatory was welcomed by responses from the wind industry and other variable renewable generation. These responses reiterated their opposition to a mandatory day-ahead market, even with a best endeavours obligation. A number of these respondents stated that a mandatory Day-Ahead Market would discriminate materially against them, essentially forcing them to participate in a market which would expose them to additional and unnecessary risk.

Respondents who did not support the move from mandatory DAM to collective exclusivity argued that it will weaken the incentives for generators to offer output into the DAM. They claim that it therefore will be less likely that there will be sufficient liquidity in the important Day-Ahead timeframe. These respondents argue that this will result in Day-Ahead schedules that will need greater adjustments by the TSO to reach an actual dispatch that is feasible. This is because if less volume is traded in the DAM then the TSO will have less information at the Day Ahead stage and will have to plan for contingencies and make dispatch decisions that may not have been necessary in hindsight. These respondents also raised concerns that this decision would weaken the robustness and reliability of the DAM price, which is a fundamental pillar of the proposed market arrangements.

Reliance on EUPHEMIA

Respondents stated that they do not yet have confidence in the ability of EUPHEMIA to reflect the conditions of the SEM.

Many respondents noted that the schedules produced by the EUPHEMIA algorithm will be unlikely to be fully feasible and will need to be adjusted to take into account ramping characteristics of plant and transmission constraints. As a result the majority of respondents wanted to wait until they had seen the results of the EUPHEMIA testing by EirGrid before making a final decision on whether it is fit for purpose.

The key risks raised by participants related to the uncertainty surrounding the estimation of net demand and to the internalisation of start-up and no-load costs in offer structures. One respondent stated that the requirement for generators to internalise their start up and no load costs together with the issue of scheduling risk will mean that portfolio players will have an inherent advantage. This is the result of the increased market information they hold when formulating bidding strategies, particularly in the DAM.

Importance of DAM

One respondent (the Viridian Group and its consultants) argued that the SEM Committee had placed 'undue weight' on a 'derivative product' (i.e. the DAM) to the detriment of the underlying commodity (the balancing market and the physical consumption and production of energy in real time). The respondent argues that the SEM Committee has placed too much emphasis on the day ahead institutions in its Draft Decision and Draft Impact Assessment. This was stated to prejudice and create bias in the selection of a preferred option that promotes day ahead trading and places relatively less weight on real time markets and efficient dispatch.

Unit-based bidding

The second element of the draft decision, the requirement for unit-based bidding for generation with provisions for aggregation of renewable generation, was supported by the majority of respondents who discussed the issue. Respondents stated that it would aid transparency of price formation and is an important element of the market power mitigation strategy that should be retained. Some respondents wanted the provision for aggregation to be extended to all variable renewable generation. There was some confusion as to whether both DSUs and AGUs fall within this group for the purposes of aggregation bidding. Respondents asked for clarity on this issue from the SEM Committee.

2.2.3 SEM COMMITTEE RESPONSE

Exclusive vs. Mandatory DAM

The SEM Committee agrees with the emphasis placed by respondents on the requirement for a robust DAM reference price based on liquid trading. The successful implementation of the I-SEM will require effective trading in all timeframes to support the most efficient dispatch in real-time. A liquid DAM will not on its own be sufficient for the successful implementation of the I-SEM either for market outcomes or as a robust starting point for dispatch; however, it is a very important element of an effective set of trading arrangements, as acknowledged by respondents to the Draft Decision Paper.

In general, respondents were supportive of the desired outcome of a liquid DAM – the issue is whether or not this is best delivered by a mandatory participation requirement.

On balance, the SEM Committee is of the view that, after taking into account the arrangements as a whole, there are clear incentives to trade in the DAM for all types of market participants within the current HLD. This is based on the following:

- trading in DAM is a main route to the wider European market through physical access to interconnector capacity for all market participants;
- the collective exclusivity of the centralised DAM, IDM and Balancing Markets as routes for contract nomination and physical scheduling of generation;
- a market participant that has hedged parts of its portfolio in the Financial forward

- market will trade at least the hedged volume in the DAM as the reference market;
- suppliers who have not fully hedged their demand with forward products will be likely to use the DAM to secure volumes on a sculpted profile;
 - variable renewable generation will have incentives to sell its forecast output (on a risk-adjusted basis) in the DAM to secure stable prices from the most liquid auction available in the I-SEM;
 - thermal generators will be able to choose from a much greater set of bid and offer formats to manage start-up and no-load costs than will be available in continuous intraday trading; and
 - the day-ahead market is expected to be a key market for demand-side offerings as identified in the RAs' 2020 Demand Side Vision.

Therefore, the SEM Committee expects that liquidity will be high enough in the DAM without having to mandate participation, particularly given the practical difficulties identified in enforcing mandatory participation requirements.

Even on a best endeavours basis, a mandatory solution could impose a disadvantage on variable market participants who are dependent on a forecast (such as wind, solar, and load) that will change closer to real-time and thereby expose these market participants to an imbalance based on forecast errors. With exclusivity, these participants will have the opportunity to risk-adjust their forecasts to trade in the timeframe(s) that gives them the best certainty.

The importance of a liquid DAM means that the SEM Committee will follow developments closely and, if required, will take additional measures to secure a sufficiently high level of liquidity. The SEM Committee also reserves the right to require mandatory participation in the DAM if it judges this to be necessary as a market power mitigation measure. This issue will be considered further during the detailed design and implementation stage of the I-SEM arrangements. In particular the detailed design phase will consider the specific implementation of Balance Responsibility and what requirements might be placed on Balance Responsible Parties in the market.

Reliance on EUPHEMIA

The provisions of the EU Target Model include a requirement for a single price-coupling algorithm to simultaneously determine prices, quantities and scheduled interconnector flows at the day-ahead stage. The EUPHEMIA algorithm will fulfill this role and has been in operation for 15 countries since February 2014. EUPHEMIA is therefore the only basis for operation of the DAM in the I-SEM.

Having confirmed the decision to retain a centralised market arrangement for I-SEM, the only alternative to full reliance on EUPHEMIA is the retention of a pool type arrangement, be it ex-ante or ex-post. However, the SEM Committee consulted on this type of option in the I-SEM HLD Consultation Paper and has decided not to take it forward based on the outcome of an extensive assessment process, including careful consideration of consultation responses and other stakeholder engagement. The implementation phase of the I-SEM will

include work to ensure that EUPHEMIA can deliver upon the requirements of the I-SEM.

As noted above, EUPHEMIA is already operational across a large part of Europe. While most markets use portfolio bids, the Iberian market currently utilises unit bids within EUPHEMIA, which demonstrates that it can accommodate unit bidding. The emphasis in the implementation phase will therefore be to ensure that EUPHEMIA can successfully be used in an I-SEM context by I-SEM units. In addition to the core EUPHEMIA algorithm, there will be a comprehensive set of fallback procedures to be called upon in the event that EUPHEMIA does not reach a solution. These fallback arrangements will also form part of the detailed design and implementation of the I-SEM.

EUPHEMIA Testing

Given the importance of EUPHEMIA in the I-SEM, and in the Target Model as a whole, it is important to complete a detailed testing programme with clearly specified goals. SEMO is engaging with the Price Coupling of Regions (PCR) Group as an associate member to put forward test cases for testing by the algorithm working group.

The aim of the testing will not be to determine whether or not to use EUPHEMIA in the I-SEM, as a liquid DAM will be at the heart of any market arrangements compliant with the Target Model. Rather the testing will inform the detailed design and implementation phase to ensure that the use of EUPHEMIA can be tailored to best meet the needs of the all-island market, including using the outturn results from EUPHEMIA as the starting point for unit commitment and dispatch by the TSOs. This should reflect the importance of a transparent and liquid DAM with unit-based bidding for most generation.

The detailed testing process will seek to ensure that the maximum possible flexibility is available to market participants in terms of Order structures, to the extent that it is feasible and cost-effective. During this process, it will be important to understand the drivers of any existing restrictions on Order formats in other markets. It is important to understand whether these are the result of legacy systems, for example in local power exchanges rather than any inherent feature of EUPHEMIA. This will then feed through into the decisions taken in the implementation phase. As acknowledged by respondents, the issue of scheduling risk arises even in a pool with a fully complex set of bids.

In addition to the formal testing the advantage of EUPHEMIA already being in operation will allow I-SEM to benefit from nearly 3 years of practical operation and experience of EUPHEMIA across a large part of the European electricity market, rather than relying on a completely new algorithm (as was the case at the launch of the SEM).

More detail will be provided on the testing programme as part of the public workplans for the detailed design and implementation stage. At a high level, the aim of the first stage of testing will be to determine whether there is any technical limit on the number of different types of bids and offers that can be provided on a unit basis to the DAM in the I-SEM. It will be important to understand the extent to which any limitations are related to EUPHEMIA itself or to front end systems.

The second stage of testing will investigate whether any limitations on bid and offer formats are needed to ensure that EUPHEMIA produces robust schedules and prices. In practice, any set of market arrangements have contingency procedures for such circumstances during operation, including the SEM itself.

If the testing of EUPHEMIA identifies specific issues that need to be addressed in the context of I-SEM then such issues will be dealt with through the governance structures. The algorithm currently has a change control process and generally has two releases per year.

It may be that this testing program results in some limitation of the bid and offer types allowed in order to facilitate the best overall solution for the all-island market. Any such limitation should not be more onerous than for any existing market.

Feasibility of EUPHEMIA Solutions

Respondents have raised concerns about the possibility for EUPHEMIA to produce infeasible schedules for individual market participants.

The SEM Committee notes that reports commissioned by market participants have stated that ramp rates can be represented in all but the simplest Orders into EUPHEMIA. It should also be noted that EUPHEMIA order structures allow generators to accommodate different ramp rates at different output levels, which they cannot do in the current SEM. The ability to reflect ramp rates in most Order types into EUPHEMIA should help to mitigate the risk of major infeasibility for an individual unit in the Day-Ahead schedule, assuming that it accurately reflects any such technical constraints in its bid.

While the schedules produced by the EUPHEMIA algorithm may not be fully feasible, especially with respect to detailed start-up profiles, it will be the responsibility of the individual units to submit offers that are technically feasible in most aspects, i.e. to submit offers that respect the units' hourly ramp rates, minimum stable generation levels, minimum on times, minimum off times, and so on.

If there are relatively small infeasibilities, then a liquid intraday market will provide a good opportunity for market participants to refine their positions. In relation to this, the detailed design phase will consider the scope for any minor technical infeasibilities to be managed through the allowance of tolerances for differences between the contracted and nominated volumes before the intraday gate closure.

The DAM and IDM operate on an unconstrained basis within a bidding zone from a system perspective – although losses and ramp rates on interconnectors between bidding zones can be incorporated. Therefore, it is unsurprising that EUPHEMIA on its own will not directly reflect the system needs in terms of location and non-energy services. Interaction with the system services framework is currently under development. In particular, the proposed basis of payment for system services will allow market participants to internalise system service revenue streams. They therefore will have the ability to indirectly represent

some of the system needs in their bids and offers into the DAM. This should help the schedule produced by EUPHEMIA to include units which provide system services and security and thus reduce, although not eliminate, the need for subsequent TSO intervention.

The issue of scheduling risk associated with EUPHEMIA is set out in detail in Section 2.1.3. In relation to portfolio advantages, the reliance on collective exclusivity of the centralised market places and unit-based bidding for generation should be noted as deliberate measures to address the concerns about undue advantage accruing to portfolio players.

Paradoxically Rejected Orders

Respondents have raised concerns that Orders that are in-the-money can be paradoxically rejected in EUPHEMIA, i.e. orders that are priced below the market clearing price may not be scheduled.

The objective of the EUPHEMIA algorithm is to maximise total social welfare, i.e. the sum of the consumer surplus, the producer surplus, and the congestion rent including tariff rates on interconnectors if they are present. In the first step, the welfare maximisation problem, EUPHEMIA seeks to find a good selection of Orders that maximizes social welfare. Then in the second step, the price determination sub-problem, it seeks to find the appropriate market clearing price whilst ensuring that no Orders are paradoxically accepted (i.e. scheduled but losing money). If no appropriate market clearing price can be found then the price determination sub-problem is deemed infeasible. EUPHEMIA then returns to the welfare maximisation problem and forces some Orders to be rejected so that the prices will change and result in no Orders being paradoxically accepted – it is due to the dual nature of the problem that some Orders may be rejected even though they subsequently turn out to be in-the-money at the outturn market clearing price.

In the current SEM the objective of the MSP software is to minimise Production Costs. The mathematical function which minimises the Production Cost does not calculate the System Marginal Price: this is done by separate phases of the MSP software. Therefore the optimal schedule to meet the Production Cost minimisation objective does not necessarily deliver the lowest possible System Marginal Price. It follows that units could fail to be scheduled by the market software even when they could have made a profit at outturn System Marginal Prices. Therefore the issue of paradoxically rejected Orders is not unique to EUPHEMIA.

To maintain the confidence of market participants, it is of utmost importance that a market does not schedule generators that are loss-making. Therefore any solution containing paradoxically accepted Orders must be deemed infeasible and adjusted, as is done in EUPHEMIA.

Anticipating the Offers of Competitors

A report commissioned by market participants stated that in the absence of a Bidding Code of Practice it will be significantly more difficult than under the current SEM for participants to anticipate the offers of competitors, and that this increases risk for participants. The SEM

Committee is of the view that generators in a competitive, pay-as-cleared market will be incentivised to submit Offers into the DAM that reflect their true opportunity costs and not to attempt to anticipate the offers of their competitors. Moreover, a generator, offering at cost, should have less scheduling risk in the I-SEM DAM than in the current SEM due to the lack of the unpredictable 'Uplift' component in the DAM price. Also, if a generator in I-SEM is not scheduled in the DAM even though its cost is lower than the DAM price (due to a paradoxically rejected order) it will have the opportunity to sell in the Intraday Market, which also reduces scheduling risk.

Importance of the DAM

The SEM Committee does not agree with the argument that the Draft Decision and Draft Impact Assessment give undue weight to derivative products (that in this context is the DA and ID markets) to the detriment of the underlying commodity (i.e. real time supply and demand).

Day-ahead markets are common features of many electricity markets operating across the world. While the day ahead market is essentially a forward market that allows participants to hedge the real time or balancing price, it has a further role in allowing other forward contracts (and financial transmission rights) to be settled against the day ahead price rather than the balancing price. In the organised ISO markets across the United States (PJM, New England, New York, California) day ahead markets have emerged to complement the real time market, in particular to allow generators with longer start up times to manage their risks and to prevent market power from being exploited by generators withdrawing capacity at short notice as well as providing an incentive for demand side response.

The EU Target Model is built around the coupling of the DA and ID markets, where unused cross border capacity is required to be allocated in a non-discriminatory manor initially at the day ahead stage through public auctions run by power exchanges. It is through the pooling of trading in these power exchanges combined with the implicit use of cross zonal capacity that the competitive benefits of being part of a large single market can accrue to end consumers. It is precisely the lack of firm day-ahead contracts in the SEM that has limited the benefits of market integration for SEM consumers and therefore achieving integration with the rest of the EU internal market at the day ahead timeframe is naturally a core component of the I-SEM project.

This emphasis is reflected in the SEM Committee's Draft Decision Paper and the assessment of the options against the High Level Assessment Principles, notably the Internal Electricity Market and the promotion of competition. However, we have been quite clear that the I-SEM must operate coherently across all timeframes. An efficient DAM facilitates efficient dispatch, but cannot deliver it on its own, with forward timescales being important for efficient investment decisions. Intraday and balancing markets are key mechanisms for adjusting dispatch to reflect updated information and system constraints.

The importance of robust Intraday and balancing markets with high levels of participation

was clearly set out in the Draft Decision and Impact Assessment. We will continue to work with our colleagues across Europe to ensure timely and efficient implementation of Intraday market coupling, and balancing market integration.

As stated in the Draft Decision, the focus on near term (up to one hour ahead) liquid marketplaces in the I-SEM should ensure that the full benefits of competition from neighbouring markets are brought to bear on the All-Island Market.

For this reason the SEM Committee continues to believe that centralised trading arrangements on the island of Ireland that are fully integrated into the European market places will build on the benefits of the SEM pool while overcoming its limitations.

While efficient dispatch is extremely important in any system, we do not believe that the long term interests of consumers will be served by market designs that may risk creating barriers in the all island market to cross border competition. These barriers may arise from allowing physical bilateral contracting, internal trading by vertically integrated players or continuing gross pool arrangements that risk reducing the incentives for market participants to actively compete outside of the all island market and similarly create barriers to international market participants from competing in the SEM.

Unit and Portfolio Bidding

The SEM Committee welcomes the support from respondents for the retention of unit-based bidding requirements for generation alongside the scope for aggregation of particular generation types. This will allow the I-SEM arrangements to support transparent markets whilst facilitating access by market participants of all sizes and technologies. These aggregation provisions are not intended to supersede any existing aggregation or intermediary arrangements allowed in the SEM.

The comments of some respondents that all variable renewable generation should be allowed to be aggregated is also noted. This issue will be addressed during the detailed design phase, which will determine the precise arrangements under which generation is allowed to be aggregated.

One concern raised as part of the responses related to the potential benefits for portfolio players even with unit based bidding. While the market power mitigation workstream in the detailed design and implementation phase will consider this issue in more detail it should be recalled that the current unit based bidding provisions in SEM are very clear in that they require the commercial offer build-up of each plant to represent that plant alone. There is therefore a prohibition on a portfolio player merely smearing a portfolio bid across all its units to achieve its best outcome. Each unit must participate and thereby be settled on its own standalone basis. At this stage we see no reason to move away from this position and this requirement should be implementable through market rules even in the absence of a bidding code of practice.

2.3 INTRADAY MARKET

2.3.1 DRAFT DECISION

The Draft Decision Paper set out the following decisions in regard to the Intraday Market:

- Continuous Intraday trading will be the exclusive route to Intraday physical contract nominations (with scope to introduce periodic implicit auctions as/if these develop at the European level)
- Unit-based participation for generation in general, with (gross portfolio) aggregation arrangements for DSU, demand and (some) variable renewable generation.

2.3.2 SUMMARY OF RESPONSES

As with the DAM, there was general support for the retention of unit-based bidding for generation in general, with provisions to allow aggregation of certain types of generation.

Insufficient detail in the Draft Decision

A number of respondents stated that there was not enough detail in the Draft Decision Paper on the workings of the IDM. One respondent asked, if renewable generators become major players in the IDM, whether it would be necessary for at least some of them to start acting as price-makers. This would thereby compromise their Priority Dispatch status under the current EU Renewables Directive.

Without further detail many respondents stated that it is unclear what will be in place at I-SEM go-live. This was a concern given the increasing importance of a liquid Intraday market in providing the ability to trade out positions from the DAM.

In particular, many respondents stated that given the ‘inevitable’ scheduling errors that will result from the Day-Ahead Market, they will need to ensure that they are able to correctly adjust their schedules in the Intraday Market. Respondents also stated a concern that generators wanting to adjust their position will be relying on the demand side operating in the IDM, and as yet it is unclear whether sufficient demand will be available for that purpose.

One respondent noted that it was important that interconnector capacity is valued in the Intra Day market.

Delays in the European Intraday market

A number of respondents asked for clarity on whether the EU IDM would be ready for the go-live of the I-SEM Intraday Market. One respondent noted that even in a best case scenario, the European intraday trading platform will not be in place for very long before the introduction of I-SEM. This could result in uncertainty for market participants. As a result respondents wanted the SEM Committee to begin to consider interim arrangements as to how the I-SEM IDM arrangements would function.

2.3.3 SEM COMMITTEE RESPONSE

The SEM Committee welcomes the emphasis from respondents on the requirements for a liquid IDM as one of the main pillars of the I-SEM HLD.

Insufficient detail in the Draft Decision

The EU Target Model sets out the high-level requirements for the IDM in the I-SEM in terms of continuous implicit trading alongside pricing of interconnector capacity. At a practical level, it is expected that the IDM in the I-SEM will be implemented in line with the specifications for the NWE IDM project, that is a bottom-up initiative to comply with the requirements of the EU Target Model. This will facilitate cross-border intraday trading with the BETTA market

The initial phase of the NWE IDM will be based on continuous trading of relatively simple products – single periods or simple blocks - on a first come, first served basis. As allowed under the EU Target Model, the benefits of complementary periodic intraday auctions for I-SEM will be assessed as the provisions for any such auctions develop at a European level.

The SEM Committee recognises the importance of appropriately valuing interconnector capacity in all timeframes. Therefore, it will continue to monitor and participate where appropriate in European developments on the methodology for intraday capacity pricing.

The IDM will benefit from demand side participation, but it will also be an opportunity for generators to get access to cheaper production resources to replace more expensive resources traded earlier and thereby buying back at a lower price. This opportunity for countertrading by market participants will create more buyers in the IDM than would be represented by demand side alone. Buyers selling back excess quantities purchased in the DAM will also contribute to liquidity.

Therefore, the SEM Committee believes that the design of the IDM at the launch of the I-SEM is clear. There are some detailed issues to be resolved about how balancing (and dispatch) arrangements interact with the IDM. For example, the continuous nature of the IDM means that the concept of price maker/price taker is less relevant than in a one-shot auction. In general, an IDM trade will be done between one buyer and one seller (with the market operator acting as central counterparty). The rules to ensure the retention of absolute priority dispatch in line with European requirements will be developed during the detailed design and implementation phase of the I-SEM (as discussed in Section 6.2.2)

Delays in the European Intraday Platform

Concern has been expressed by some respondents about the delays in the implementation of the European IDM platform. Even though the project to deliver the single European IDM platform has been significantly delayed to date, the SEM Committee understands that the main hurdles to the implementation have been passed with agreement on the specification and choice of vendor. The system implementation of the new solution is ongoing, and it is

expected to be ready for testing this year. The testing period is required to be extensive which means that the go live date is currently scheduled to be in Q3 2015 at the earliest. This would still leave more than a year for practical operation of the platform before it is used in I-SEM.

The lead times for implementation of the European platform mean that the system details and specifications should be available to I-SEM parties well in advance of the Q3 2015 launch date. The I-SEM will also benefit from the operational experience of the 5 power exchange partners and 16 TSOs involved in the European IDM platform.

The SEM Committee recognises the importance of the IDM as part of the I-SEM and the reliance on having an adequate platform available for all market participants to be able to have sufficient trading opportunities to trade themselves into balance.

A robust IDM therefore needs to be in place for the start of the operation of I-SEM. However, this does not mean that the I-SEM launch should be dependent on the successful launch of the European platform. During the detailed design phase, the SEM Committee will consider contingency procedures for a national or regional solution in the unlikely event that the European platform is not in established operation by the time of the implementation of the I-SEM.

2.4 BALANCING MARKET

2.4.1 DRAFT DECISION

The Draft Decision Paper set out the following decisions in regard to the Balancing Market:

- Starting point for dispatch is detailed and feasible production plans required for all market participants following DAM.
- Mandatory participation in Balancing Mechanism after Day Ahead Market stage
 - Unit-based participation in BM for generation in general
 - Marginal pricing for unconstrained energy balancing actions

2.4.2 SUMMARY OF RESPONSES

Mandatory participation

There was general agreement from respondents with the decision to make participation in the Balancing Market mandatory. Respondents stated that making the Balancing Market mandatory would provide the transparency and liquidity necessary to deliver an efficient solution, and facilitate reliable operation of the grid. A few respondents also said that it would address market power concerns related to portfolio players withholding generation to influence balancing prices. Another respondent noted that Virtual Power Plant auctions would be the best way to mitigate these market power issues in the Balancing and Imbalance markets.

However a number of respondents also questioned how the mandatory Balancing Market

would interact with the 'exclusive' DAM and IDM. One view raised by respondents noted that because there may be a lack of volume or liquidity in the earlier markets (due to DAM and IDM being exclusive rather than mandatory) there would be heightened anxiety, especially among suppliers, with regard to the Balancing Market. The SEM Committee should therefore give greater consideration to the proposed operation of the Balancing Market and provide more information as soon as possible to participants.

Another respondent went further stating that the Balancing Market should not be a route to market for generators. Their view was that although wind forecasts at day-ahead may contain a level of forecast error, it is more important to have a strong liquid Day-Ahead Market to provide relevant market prices. As a result the Day-Ahead Market should be mandatory to increase liquidity as this will be important in enabling demand side participants to make informed decisions.

Flagging and Tagging

Respondents stated that more detail is required as to how the single balancing price will be determined and the uncertainty surrounding the tagging arrangement that will be implemented by the TSO. A number of respondents said that more detail is essential on the mechanism for the identification and treatment of energy and non-energy balancing actions taken by the TSO due to system constraints.

Payment for energy and non-energy balancing actions

A number of respondents outlined their support for the proposal to have Pay as Bid (PAB) for non-energy actions rather than Pay as Cleared (PAC). One respondent believed that PAB pricing will help maintain transparency in the tagging process. However, other respondents questioned the efficiency of selecting bids from the same stack of offers for PAB or PAC, depending on the classification by the TSO.

Market Power Mitigation measures

One respondent stated that the Regulatory Authorities should consider local market power mitigation measures alongside the decision to make non-energy actions PAB. The respondent noted that measures such as a set of bidding principles applied to all market participants, would be the best way in which to mitigate any local market power issues.

Another respondent noted that the local market power mitigation measures are still lacking in the market design, and stated that robust measures are needed to address market power across all timeframes. The respondent stated that these should be set out in the Final Decision on the HLD.

Interaction with DS3

Some respondents stated that the uncertainty surrounding the interaction with DS3 may lead to confusion in relation to bidding strategies. One respondent stated that market

participants would have to make assumptions/estimates of DS3 revenues which would give rise to additional complications.

Role of the TSO

A number of respondents stated that because all participants will have to become balance responsible there will be a need for more frequent provision of demand information by the Market Operator in order to enable suppliers to better manage the procurement of energy to meet the demand profiles of their customers.

One respondent asserted that the dispatch schedule determined by the TSO is likely to be very different from contractual nominations, based on market results from the EUPHEMIA price coupling algorithm. This means that the starting point of dispatch would not be economically efficient and as a result balancing costs will not be fully cost representative.

Respondents from the wind industry wanted to ensure that Priority Dispatch is taken into consideration in the dispatch schedule, irrespective of the market incentives placed on individual generators to forecast generation and trade appropriately.

2.4.3 SEM COMMITTEE RESPONSE

Mandatory participation

The existing SEM has only one timeframe for short-term trading, the ex-post pool. Inevitably, when new markets are introduced, there will be concern about which of them will be liquid and whether they will be adequate for different market participants to cover their trading needs.

The balancing arrangements are a market of last resort for energy balancing but of prime importance to the TSO in balancing the system. As a consequence balancing arrangements will be permitted to open in parallel to the intraday market to allow the TSO time to ensure there is sufficient balancing energy available. At the same time, making the DAM and IDM collectively exclusive for trading between market participants to support physical scheduling should ensure that as far as possible physical trading is conducted in the centralised markets. The incentives for trading in the DAM is discussed in more detail in Section 2.2.3 under the heading of whether the DAM should be mandatory or exclusive.

Flagging and Tagging

The detail of how to separate “energy” balancing actions from “system” balancing actions in different markets varies considerably. In practice there is no perfect way to achieve this separation; many TSO instructions will have more than one rationale and ultimately the appraisal of individual balancing actions will be influenced by hindsight.

The core requirement is that the mechanism chosen, as well as the underlying dispatch decisions, are based on an objective set of principles. For example the arrangements should be transparent and not unduly susceptible to human intervention which would make the

results difficult to interpret or to predict.

During the detailed design phase the SEM Committee will work with market participants and the TSO to create the necessary principles and the working procedures needed to deliver and enact these principles.

Payment for energy and non-energy balancing actions

Electricity markets worldwide adopt different approaches to the pricing of balancing actions, including which balancing actions are settled at market-wide clearing prices (PAC) and which are settled at bespoke prices, i.e. PAB.

The proposed separation of balancing actions in I-SEM is fairly typical, in that the pricing of energy actions is to be market-wide as these services are considered to be homogeneous. The energy cost of delivering system actions, e.g. positioning to deliver system services and any re-dispatch to satisfy constraints within price zones, are settled at bespoke prices. This reflects the more heterogeneous nature of these services, i.e. specific units because of their characteristics or their location are required to resolve specific issues. For the non-energy costs of delivering defined system services, separate payment arrangements will apply in the I-SEM. These are being developed as part of the DS3 programme of work which is discussed further below.

Under the I-SEM, energy balancing actions will be settled at the marginal clearing price. This is in line with the EU Target Model. Under Article 38.2 of the December 2013 draft of the Electricity Balancing Network Code submitted by ENTSO-E to ACER, the default is for marginal pricing, with any alternative requiring the TSOs across Europe to demonstrate that a different pricing model is more efficient.

The use of a clearing price for energy balancing gives incentives for participants to bid at their own marginal cost. It improves access for small market participants who under alternative arrangements would be at a disadvantage, and provides a single reference price for energy balancing actions.

In principle the offers in the Balancing Mechanism in the I-SEM may be called for energy balancing, paid at a clearing price, or for system balancing, paid at bid price. Acceptance of certain system balancing offers might mean that the participant is expected to hold the output of a unit at, above or below a certain level whereas other offers might leave the unit freer for continued trading within the intraday market.

The details of the bid formats will need to be considered at the detailed design stage but in principle the arrangements will place responsibility on market participants to form their own bidding strategies notwithstanding any constraints from market power mitigation or other contractual obligations. This will be supported by a responsibility on the TSO to make appropriate information available to market participants.

Interaction with DS3

When implemented, the DS3 arrangements will result in a series of contracts for system services in which the prices are generally known by producers in advance. The delivery of most of the DS3 services is dependent on the energy dispatch of the units concerned. Therefore, the system service procurement arrangements may allow market participants to internalise system service revenue streams. Therefore, they can indirectly represent some of the system needs in their bids into the DAM and other markets. This should help the schedule produced by EUPHEMIA to include units which provide system security and reduce the need for TSO intervention.

The precise detail of the interactions will be considered further at the detailed design stage. Issues will include which actions or instructions (if any) the TSO issues before the day-ahead market, and whether there are any predetermined prices for system actions relating to DS3 contracting. The interaction of DS3 with the Reliability Options will also be considered further at that stage.

Role of the TSO

The implementation of new market arrangements will bring new challenges for the TSO and market participants. The basis of the EU Target Model and of the I-SEM is that market participants rather than the TSO take responsibility for their energy balancing until close to physical delivery.

The EUPHEMIA algorithm and the continuous matching function in the IDM will not explicitly cover non-energy balancing services. As a result, the real dispatch will differ from the market schedules, requiring a separate set of Balancing actions to be procured by the TSO. We note that the existing SEM also separates system actions from energy scheduling.

This transition will require a greater exchange of information between participants and central systems than the present market. Therefore, the details of these information requirements will be developed between the TSO and market participants as part of the detailed design phase.

In the transition period it is to be expected that the TSOs will adopt a conservative position, as they build experience of the interaction of the results from EUPHEMIA, the IDM and the suite of balancing bids and offers. The DAM is the starting point for scheduling decisions and interconnection flows, and is anticipated to be the reference market for financial forward trading. Therefore, the SEM Committee is mindful of the need to ensure adequate liquidity in the DAM to ensure that it can adequately fulfill these different roles as well as the incentives on the TSOs to balance the system reliably and at minimum costs to market participants and consumers.

Contracting and pricing for system services is dealt with through the DS3 programme while the I-SEM will deliver scheduling and dispatch for energy. Co-optimising the delivery of system services and energy is not available under EUPHEMIA. However, if market

participants know the prices for system services at the time when they conduct their trading and scheduling decisions, energy market bidding, scheduling and pricing will reflect the need for generation units to be positioned to provide system services. There also needs to be good information sharing between participants and the TSO during the intraday and balancing timeframes.

The detailed rules around the treatment of Priority Dispatch generation in the Balancing Market will be finalised during the detailed design and implementation phase.

Market Power Mitigation

The SEM Committee recognises the potential for market power to be exercised across a range of services, from capacity and spot energy to energy balancing, system services and constraint mitigation. Conversely, the ability of the market to reveal value in different circumstances is an important driver of competition including from new entrants and from the demand-side. Market power mitigation inevitably strikes a balance between protecting consumers in the short term and delivering competition in the longer term.

It is generally accepted that electricity market designs should not be defined by the specific mechanisms to mitigate market power. Market designs are intended to endure, whereas market power can change rapidly as ownership changes, networks are developed, demand patterns change and as capacity is opened and closed. The SEM Committee has nevertheless taken the issue of market power into account in its decisions on the I-SEM High Level Design. The detailed design phase for I-SEM will address market power issues in detail across the full range of traded products. In this, the SEM Committee will draw on the experience of a variety of market power mitigation measures including those used in the SEM.

2.5 IMBALANCE PRICING

2.5.1 DRAFT DECISION

The Draft Decision Paper set out the following decisions in regard to Imbalance Pricing:

- Unit-based
- Single imbalance price
- Route to market for small players

2.5.2 SUMMARY OF RESPONSES

Discriminatory for wind generation

Respondents from the wind industry stated that the imbalance market as proposed in the Draft Decision Paper is discriminatory against wind, and must be reviewed without delay. They indicated that independent wind generators will inevitably be exposed to the imbalance settlement price. Even if they trade actively in the Day-Ahead and Intra-Day Markets, the variability of wind will mean that they will always have either under or over-

sold, and hence be exposed to the price in the imbalance settlement mechanism. A subset of these respondents stated that there is no obvious reason why a SEM-like pool could not be used instead.

Definition of marginal imbalance price

Respondents also sought clarity on whether the imbalance price should be priced at the marginal MWh. Some respondents highlighted that due to market power concerns and the likely level of overall system balancing error, especially in the early stages of the I-SEM, the SEM Committee should examine a Price Average Reference (PAR) higher than 1MWh for calculation of imbalance prices. Many respondents agreed with this and suggested that transitional steps over a number of years should be implemented prior to setting PAR at 1MWh.

One respondent stated that the decision to set the imbalance pricing on the marginal MW of energy balancing actions appears to be a hasty decision made with no rationale as to its choosing, or impact assessment of the consequences. This respondent continued to state that if the last MW of energy balancing action is set on the imbalance price, it would place additional stress on the “flagging and tagging” by the TSO. This respondent asserted that because the correct identification of energy balancing actions is difficult, it may result in imbalance prices that have more to do with the efficiency of tagging than actual production costs.

Another respondent noted that while they supported a single imbalance price, if there was a decision to move to dual imbalance pricing it would be important that it is accompanied with greater freedom for portfolio bidding for priority dispatch generation.

Aggregator of last resort

Respondents also broadly supported the introduction of an aggregator of last resort, as a transitional mechanism to ensure a route to market for small market participants. Responses were more mixed on who should perform this role and whether the Aggregator should be enduring or transitional.

Respondents from the wind and solar industries stated that the TSO should provide this role on an enduring basis, as it would reduce some of the risks faced by intermittent generation in the market.

Other respondents noted that appointing the TSO to this role may hamper the natural emergence of aggregators on a commercial basis over time.

2.5.3 SEM COMMITTEE RESPONSE

Fairness for wind

The concept of Balance Responsibility for all parties, including for variable renewable

generation and for demand, is at the heart of the EU Target Model. The definition of Balance Responsibility is found in Article 2 (definition) and Article 24 (role) of the December 2013 draft of the Network Code on Electricity Balancing submitted by ENTSO-E to ACER. Balance responsibility is successfully implemented in many European markets; also in markets with high penetration of RES, for instance Spain, Germany and Denmark.

Uncertainty and forecast error imposes costs on the system. Ultimately, the delivery of an efficient and equitable system relies on market participants being exposed to the costs that they impose on the system. Similarly, where generation provides additional benefits to those directly recognised in the wholesale electricity market, then additional revenue mechanisms are in place to recognise these benefits.

It is important that all market participants, including small independent players, have suitable access to the tools to discharge this responsibility through their activities, including forecasting and trading. Therefore, the move to an imbalance pricing regime should be considered as part of a holistic solution, rather than as a stand-alone measure.

The other aspects of the HLD that will help provide the tools needed include:

- Emphasis on ensuring routes to market are in place for market participants of all sizes and technologies, including retention of the concept of Intermediary. This would allow parties to delegate the trading activities to other market participants, allowing smaller market participants to benefit from economies of scale and avoiding burdening them with a requirement for 24 hour trading capabilities.
- Emphasis on physical spot trading in centralised, transparent market places from the day-ahead stage to very close to real time to ensure that it is not just portfolio players who are able to benefit from diversity in managing their energy balance – at a European level, the wind industry associations have highlighted the need for liquid intraday markets close to real time to help the integration of variable renewable generation. The purpose of the IDM is that participants can trade to mitigate imbalance costs and variable renewable generators are being provided with opportunities to trade on a portfolio basis.
- A single imbalance pricing regime to deliver cost-reflective prices, and reduce offsetting advantages of portfolio players (who, under a dual pricing regime with imbalance settlement at portfolio level, could net out offsetting imbalance and thereby reduce costs compared to independent participants).

In addition, transparency of information is important in the current SEM design and appropriate mechanisms will be important in the I-SEM to ensure that timely and comprehensive information is provided to market participants, including the provision of wind forecast information.

The treatment of variable generation is not discriminatory as all generation and load who have deviations in demand or generation output are treated in the same manner. A generator that trips or fails to start after selling output in the DAM faces the same imbalance settlement as a wind generator whose output drops with lower wind. The same applies to a demand portfolio which uses less electricity than expected, for example

because temperatures are higher on a winter day than expected.

The Impact Assessment process has identified the benefits of an effective imbalance pricing regime in encouraging effective ex-ante trading outcomes that will deliver beneficial outcomes for variable renewable generation. This includes reduced reliance on the TSO to take actions to manage the energy balance, and more efficient scheduling of the interconnector to reduce, even if not eliminate, the reliance on TSO countertrading. The move to an IDM and balancing regime as part of the overall HLD will also encourage the development of more flexible resources. This will be an important part of helping the system to accommodate higher levels of wind.

In summary, an effective imbalance pricing regime will change the nature of participation in the market for variable renewable generation. Market participants should recognize this move as being part of a coherent set of trading arrangements in line with the spirit of the EU Target Model. The arrangements for the I-SEM emphasise that Balance Responsibility must be accompanied by the tools to discharge this new responsibility.

The SEM Committee also notes the concerns of variable renewable generators about the impact of rising curtailment on the market revenues and perception of riskiness of investment in variable renewable generation.

There are a number of policy initiatives in place to address the issue of curtailment, with important work being done as part of the DS3 programme to raise the threshold for curtailment. There will also still be circumstances in which TSO countertrading will be required to reduce curtailment. Therefore, the SEM Committee considers that the proposed option for the HLD will provide a package of measures that will best deliver signals to flexible resources within the energy market that will help to alleviate curtailment. – these flexible resources include interconnector capacity, and demand-side response (which will be facilitated by a strong DAM). This will have a direct impact on the ability of wind to access the market schedules, with a reduced reliance on TSO mitigation activities.

Definition of marginal imbalance price

The precise definition of the marginal imbalance price has been raised in a number of responses, including the scope for transitional arrangements. This reflects the fact that the topic has been the subject of much debate in many European markets.

This includes the neighbouring BETTA market where the regulator, Ofgem, has extensively reviewed the calculation of imbalance prices, including most recently as part of the recent Electricity Balancing Significant Code Review (EBSCR).

Ofgem's decision on the EBSCR means that the imbalance price in the BETTA market will become sharper than at present – as it moves from being based from the top 500MWh of accepted bids, the so-called PAR500, to the top 100MWh, and then finally (by winter 2018) to becoming fully marginal (i.e. based on the top of 1MWh of accepted bids). This change in

the definition of the marginal imbalance price is happening as part of a package of measures, which includes a move from dual to single imbalance pricing.

Ultimately, an imbalance pricing regime should accurately reflect the costs to the TSO of taking energy balancing actions, whilst providing robust signals for market participants to take actions that would support the maintenance of the balance between energy supply and demand. This signal is best delivered through a single imbalance pricing regime based on marginal pricing to provide the appropriate incentives.

The detailed definition of the marginal bid and offer used to set the imbalance price in each settlement period will be an important issue to be addressed in the detailed design phase. The issues to be considered include, but are not limited to:

- the duration of bid and offer acceptance required to be the marginal bid or offer – i.e. the treatment of energy balancing actions shorter than the imbalance settlement period.
- the volume of bids and offers defined as being the marginal amount;
- the granularity of metering; and
- the process for separating energy balancing bids from system balancing bids (as discussed in more detail above).

The SEM Committee will look at experiences in other markets, for example BETTA, when examining the precise definition of the marginal unit with industry as part of the detailed design phase.

The SEM Committee acknowledges the concerns raised by variable renewable generators about their exposure to imbalance prices under a move to a Balancing Market rather than an ex-post gross pool. This is to some extent the corollary of providing signals for flexibility within the market. The concept of Balance Responsibility for all parties, including for variable renewable generation and for demand, is at the heart of the EU Target Model. Balance responsibility is successfully implemented in many European markets; also in markets with high penetration of RES, for instance Spain, Germany and Denmark.

Ultimately, the delivery of an efficient and equitable system relies on market participants being exposed to the costs that they impose on the system. Similarly, where generation provides additional benefits to those directly recognised in the wholesale electricity market, then additional revenue mechanisms are in place to recognise these benefits

Aggregator of last resort

It is very important that the I-SEM arrangements provide access to all market places for market participants of all technologies and sizes. The I-SEM will therefore include mechanisms to ensure effective routes to market for smaller players.

For the avoidance of doubt, the implementation of a route to market for smaller players is not intended to deliver the aggregated volumes for these players directly into the imbalance arrangements, as a short-circuit of the DAM and IDM. The intention is to facilitate access to

and participation in the ex-ante markets in order to reduce exposure of these players to the imbalance arrangements and in order to enable them to avoid the costs of developing individual forecasting and trading tools.

Ideally, the services would be provided commercially but there is a material risk that this would not happen without regulatory impetus. Conversely, the existence of a 'last resort' offering risks crowding out commercial offerings. These two viewpoints were echoed in the consultation responses.

Participants' also commented on potential conflicts of interest with the TSOs providing an aggregator service. The identity of the provider, and the detailed design, of the aggregator of last resort will be finalized in the detailed design phase. However, where such aggregators have been implemented in other markets, they have tended to be carried out by the TSO in the first instance. It was for this reason that the Draft Decision stated that the aggregator would likely be the TSO at market go-live. As mentioned above, the operation and identity of the aggregator will be examined further in the detailed design and implementation phase.

3 RETENTION OF CAPACITY REMUNERATION MECHANISM

This section provides a summary of the responses received to the proposal to retain a Capacity Remuneration Mechanism (CRM) in the I-SEM.

3.1.1 DRAFT DECISION

The SEM Committee proposed that a CRM is required in the High Level Design of the I-SEM and developed in parallel to the energy market detailed design in light of:

- The economic rationale for an explicit capacity remuneration mechanism given the market failures associated with energy only markets, giving rise to the missing money problem.
- The magnification of these market failures meaning that the missing money problem is particularly acute in a small island system with high levels of variable generation
- The Impact Assessment of the need for a capacity remuneration mechanism against the I-SEM primary and secondary assessment criteria.
- Evidence from the TSOs Generation Adequacy reports (the Generation Capacity Statement and the Adequacy Report for an Energy Only Market)
- Pöyry modelling analysis on the impact of the changing system dynamics on the running patterns and hours of conventional generation as a result of the increased penetration of low carbon renewable technologies.

3.1.2 SUMMARY OF RESPONSES

From respondents who mentioned the issues there was unanimous support for the need for a CRM within the I-SEM HLD. There was agreement that a CRM is needed to address the continued issue of missing money.

3.1.3 SEM COMMITTEE RESPONSE

The SEM Committee welcomes the support from respondents for the retention of an explicit CRM in the I-SEM to address the challenges highlighted in the Draft Decision Paper.

Respondents stated that the primary driver of the need for a CRM in the all-island market is to address the issue of missing money. This issue is particularly acute for a small island system with high penetration of variable renewable generation.

The SEM Committee looks forward to working with stakeholders to deliver an explicit CRM that best addresses these challenges, when judged against the assessment criteria decided for the I-SEM and notes that it should be compatible with any relevant European guidelines.

4 FORM OF CAPACITY REMUNERATION MECHANISM

This chapter provides a summary of the responses received in regard to the proposed HLD of the Capacity Remuneration Mechanism (CRM) for the I-SEM. It is structured in line with the main elements of the proposed decision:

- Choice of a quantity-based CRM; and
- Choice of reliability options as the preferred model.

Each of these section starts with a reminder of the draft decision before summarising the responses by issue. The section concludes with a statement of the SEM Committee position on each issue.

4.1 CHOICE OF A QUANTITY BASED CRM

4.1.1 DRAFT DECISION

The I-SEM will have a quantity-based Capacity Remuneration Mechanism.

4.1.2 SUMMARY OF RESPONSES

Price vs. quantity based CRM

A number of respondents favoured a long-term price based CRM stating that it remains the most appropriate choice for the I-SEM (taking account of the special requirements of a small and relatively isolated island market). Many respondents stated that given the unique circumstances of the All-Island Market, a move away from a priced based mechanism would reduce certainty around generator revenue streams, leading to a reduction in investor certainty (given that many investments were committed on the basis of the current capacity mechanism). This may lead to a possible boom/bust cycle for generators as the system moves between shortage and surplus.

In addition, market participants would need to anticipate the amount of infra-marginal rent they will capture in the energy market in order to inform their auction bidding strategy. This increase in risk is likely to result in a high risk premium being applied to auction bids.

One respondent stated that the location and type of investment in generation capacity over the past seven years had not been optimal. As a result this respondent stated that it is important that the SEM Committee sends the right investment signals to ensure that future energy needs are met through the new market design.

Legitimate expectations

A key issue raised by respondents is related to the treatment of renewable generation under a quantity based CRM. A number of respondents stated that there has been a lack of

consideration of the capacity credit for renewables, resulting in many renewable technologies (especially wind) not being in a position to participate given the risks involved. This led to a view that the move from a price based CRM would be discriminatory.

One respondent stated that they had received legal advice that there is potential for a legal challenge to the decision on the CRM on the grounds that *“wind participants had **legitimate expectation** of receiving remuneration under the current CRM that is removed under the proposed RO.”*

It further stated that it *“believe(s) the Proposed CRM goes beyond what might be considered a proportionate means of achieving the desired level of competition in the market”* and that it *“believe(s) the proposals would in fact have an anti-competitive effect on the market in general, as a result of reducing the ability of a large section of market participants to bid for ROs.*

An additional respondent stated that as a result of this discrimination wind generators may also be have case to make for a *‘disproportionate interference with property rights contrary to Article 1 of the First Protocol of the European Convention on Human Rights.’*

4.1.3 SEM COMMITTEE RESPONSE

Price vs. quantity based CRM

It is helpful here to restate the major differences between price-based CRMs and quantity-based CRMs that have been considered for application in the I-SEM.

Price Based Scheme

A ‘price-based scheme’ is defined as a scheme where:

- capacity remuneration depends on availability in a particular period (i.e. there is no advance commitment to deliver capacity); and
- the capacity payment is paid to all eligible generation – i.e. there is no process in allocating payments based on a merit order of the cheapest providers up to a centrally determined quantity.

In this sense, ‘price-based’ does not mean that the central body necessarily fixes the level of payment received by each capacity provider. Instead, the central body can fix the relationship between quantity of capacity provided and the price received. For example, this can be done by fixing a total pot for capacity payments with the price then determined by the amount of capacity provided.

This means that in a price-based scheme, there is no direct competition between the providers to receive the payment in any period. Instead, the quantity of eligible capacity determines the price based on the administered pricing function. If more capacity is

available, that will reduce the remuneration received individually by everybody, and capacity will be provided as long as the costs are below the price.

However, the key point is that the central body effectively fixes the price, either directly or through the pricing function. The market then determines how much capacity is provided, with only limited prospects for price discovery through competitive pressures.

Quantity Based Scheme

The SEM Committee has defined a ‘quantity-based’ scheme as one in which:

- providers receive an advance payment for capacity, in exchange for a commitment to deliver either capacity or energy in certain required periods and face an implicit and/or explicit penalty if unable to do so ; and
- there is direct competition between providers to receive the payments with payments allocated to a centrally determined quantity based on a merit order of bids.

A central body determines the amount of generating or demand reduction capacity to be procured and uses a market mechanism, typically an auction, to discover a price for this capacity. The procurement would generally be open to all resource types that can meet the required performance criteria.

In a quantity-based scheme, the price-quantity relationship determines the ceiling on payments made by consumers, with the scope for lower total payments depending on the bids received from capacity providers.

“Market Based” References

Some respondents have interpreted the term ‘market-based’ to mean that there is no regulatory intervention at all in the CRM. This is a very ‘black’ and ‘white’ view of the world which ignores the fact that in any market, including the current SEM, regulatory decisions provide the framework for effective competition. For example, this will include ensuring that the market design facilitates competitive pressures, as well as specific market power mitigation measures, many of which have been used in the SEM.

Therefore, the difference between market designs is the balance between the reliance on regulatory rules and competitive pressures. The use of regulatory rules does not invalidate the description that quantity-based CRMs take a market-based approach to determining the total level of consumer payments, within regulatory bounds, whereas in the price-based CRMs the total level of payments are effectively determined administratively.

The Impact Assessment sets out in more detail the reasoning for the decision to move to a quantity-based CRM in the future. This is because it will best address the challenges identified for delivering generation adequacy on the island in the most efficient way for all-island consumers.

Arguments for retaining the current Capacity Mechanism

The SEM Committee notes that a number of respondents in favour of the retention of a long-term price-based CRM seem to prioritise stability of capacity revenues for existing generation above all aspects of the scheme. The efficiency of market exit and entry, total costs to consumers over an extended period, and the compatibility with European guidelines are all important considerations in determining the shape of the CRM.

It is important to recognise that a long-term price-based CRM does not necessarily provide a long-term guarantee of revenue certainty for all generation during their operational lifetime. There has been one review of the current capacity mechanism, which signaled that the scheme would be reviewed again as part of this Market Integration Project. At the same time, there have been changes to the input values and parameters, which have changed the level and distribution of payments. Further change in parameters may have been required with increasing levels of wind installed capacity.

In addition, the consultations on the proposed procurement arrangements for system services has highlighted the possible interactions between increased system service payments and capacity payments were the current capacity payment arrangements to remain in place.

Efficient Entry and Exit Signals

A number of respondents to the Draft Decision raised concerns that the move to a quantity based scheme could lead to less than efficient entry and exit signals in the market. Many of these respondents have argued that the current capacity mechanism provides more stable signals for entry and exit.

Achieving the correct balance that would ensure efficient entry and exit signals is difficult and a quantity based scheme can achieve this. As with the current CRM much will depend on detailed design considerations.

Some respondents also suggested that a price-based scheme could be modified to provide stronger exit signals. However, this would then compromise the revenue certainty that is seen as so important for a long-term price based scheme and may in fact increase the risk of a boom and bust cycle compared to a quantity-based mechanism.

For example, it is the specific design of the current capacity mechanism which provides short term stability to plants already in the market. The flattening power factor and the ex-ante nature of 70% of the payments make the revenue streams quite certain within this timeframe. A higher ex-post weighting or an increased flattening power factor could make the profile of payments much different, and significantly change the revenue obtained under the scheme by different plants.

Concerns have been expressed over exit signals in the current SEM capacity mechanism. For example, in 2010 a group of potential generation investors in SEM stated the following with

regards to exit signals (see SEM-11-088a, where CPM refers to the existing capacity mechanism).

Regarding efficient market exit signals for old, inefficient and unreliable plant it is not clear that these signals exist under the current CPM rules; we suggest that under current CPM rules where a capacity surplus exists, there is no incentive for old, inefficient, under-performing plant to exit the market. The continued presence of these plants dilutes the economic signal to the type and quality of new plant required for security of supply in the future.

It is not the intention to implement a CRM which encourages a boom and bust cycle. In this context, respondents made observations on the New England scheme. The capacity pricing in New England would appear to have varied in the past. However, the New England ISO is currently introducing a sloping demand curve into their forward capacity market. The GB capacity auctions will also employ a sloping demand curve. As mentioned above, international experience will be reviewed when developing the CRM in I-SEM and consideration of a sloping demand curve will likely form part of that consideration.

Legitimate expectations

In its response to the Draft Decision on the I-SEM HLD, IWEA stated the following in relation to their contentions around legitimate expectations.

“IWEA contends that should the Proposed CRM were to be adopted, there is a potential for it be challenged on grounds that participants in the wind sector have a legitimate expectation of receiving remuneration payments under the Current CRM.

The argument being such that, when deciding to invest in Ireland, affected participants relied to a significant degree on the regulatory arrangements in place at the time, including the Current CRM as set out in the Code, and on the understanding that these regulations would continue into the future.

The SEM Committee carries out its respective functions in the manner which it considers is best calculated to further the principal objective to protect the interests of consumers by promoting effective competition in the SEM, having regard to the need to ensure, inter alia, security of supply, and licensee’s ability to finance its activities. While the SEM Committee is mindful of the duty to perform its respective functions proportionately, consistently and in a manner which adheres to due process, the SEM Committee considers that the proposal to replace the current capacity mechanism with the new CRM is in line with the foregoing.

In the SEM Committee’s view, a legitimate expectation cannot be said to arise to the effect that the current capacity mechanism would not be significantly altered or, if necessary, replaced at some stage in the evolution of the electricity trading arrangements on the island.

While recognising that it is the Courts that would ultimately decide on this matter, the SEM Committee is satisfied that the proposals to move away from the current capacity mechanism are not inconsistent with any legitimate expectations of licensees and is in line with the SEM Committee's statutory functions and duties.

4.2 CHOICE OF RELIABILITY OPTIONS FOR THE CRM

4.2.1 DRAFT DECISION

The form of CRM will be Reliability Options issued by a central party.

4.2.2 SUMMARY OF RESPONSES

General

A majority of respondents were not in favour of the decision that the form of the CRM will be Reliability Options issued by a central party. Based on the Draft Decision Paper respondents had a range of issues including perceived discrimination against certain technologies, the need for physical back-up and general lack of detail surrounding the decision. Respondents also wanted to ensure that lessons are learnt from the ISO New England Reliability Options scheme, and the decision to implement a quantity-based CRM in GB.

A number of respondents stated that it was unclear whether the benefit from Reliability Options would be worth the additional complexity. The view expressed was that this complexity will have the potential to de-stabilise the market, particularly for renewables and demand side participants. Complexity may also lead to additional regulatory risk and amplified exposure to scheduling risk. Another respondent cautioned that a move to multiple strike prices would reduce transparency, liquidity and increase complexity further.

Some respondents broadly supported the decision on Reliability Options. These respondents stated that the proposed Reliability Options would act as a semi-fixed revenue stream for participants who can reliably assist the system in times of stress.

Discrimination

Of respondents who did not support the decision the majority stated that the current design of the Reliability Options would discriminate against wind generation and demand side participants. The view was expressed that while the proposed Reliability Options have benefits in terms of market entry and exit signals, participation would be more compatible with conventional thermal generation than renewables and demand side generation.

A number of respondents stated that Reliability Options will create implicit penalties for wind generation when market prices go high in the reference market. One respondent noted that any generator who has sold a Reliability Option would be liable to pay the

difference between the Day-Ahead Market price and the Reliability Options strike price whenever the former exceeds the latter. So if the generator actually generates in that period, it is hedged against times of very high spikes in the day-ahead price. However for variable generators, there is far greater uncertainty whether it will be able to do so. For example given the price-lowering effect of wind, such price spikes are most likely when wind is not generating. As a result wind would be penalised more than any other technology class by the Reliability Options. This would force wind generators to account for this implicit penalty into its Reliability Option offer, likely making it uncompetitive.

One respondent stated that although it is asserted that renewables would be no worse off by not participating in Reliability Options, this has since been refuted. This is because wind generators rely on capacity payments in SEM to reduce the PSO or remunerate out-of-support projects, so it will be a problem if this support is removed.

These arguments were also raised by respondents in regard to demand side participating in the current SEM. They stated that Reliability Options in principle may serve to reduce market exposure to excessive spikes in wholesale electricity prices. However, while the principle is positive, the proposed mechanism associated with achieving this is not a workable solution for demand side units that operate on the basis of avoiding energy costs rather than revenue earned from energy payments. As a result these respondents raised the need for special treatment under Reliability Options, one that excludes demand side units or the creation of a fund that would facilitate energy payments to demand side units for the provision of instructed demand reductions.

Those respondents who supported the introduction of the RO scheme stated that careful consideration is still required for variable renewables and demand side resources given their importance to broader policy objectives. As such it will be important to ensure that Reliability Options are as technology neutral as possible. The Regulatory Authorities can then use additional policy instruments to encourage or discourage certain resources accordingly, in line with their contribution to policy objectives.

Need for physical back-up

A number of respondents raised the issue of the need for physical back-up within the Reliability Options design, with only one respondent saying physical back-up would not be required.

One respondent stated that eligibility rules should require that issuers of Reliability Options have a credible presence in the I-SEM market or a future source of physical power. It would be perverse to allow purely financial players to participate in a mechanism that aims to secure adequate physical capacity

Other respondents stated that without a physical element, obligation or penalty, Reliability Options will not solve the “missing money” problem which would lead to security of supply concerns as generators are inadequately remunerated. One respondent also referred to a report by ‘The Brattle Group’ which concluded that the lack of physical back-up was a key

factor in the downfall of the Colombian Reliability Options approach.

One respondent noted that Reliability Options should be structured as pure financial instruments with no non-linear penalty mechanism. As a financial instrument all parties will seek to ultimately asset back their financial liabilities thus ensuring sufficient physical capacity.

Another respondent stated that Reliability Options would place less emphasis on reliable flexible plant and short-term security of supply than a regulated physical penalty under a volume-based capacity mechanism could be designed to do. This would place greater emphasis on DS3 Revenues to promote investment in flexibility. Other respondents stated that adequacy and flexibility are clearly separate and should not be confused, and that DS3 should be used to deal with flexibility and the CRM for adequacy.

Interaction with the forward market

Another concern raised by respondents was the interaction between the forwards market and the Reliability Options and the impact this will have on forward liquidity. There was confusion amongst some respondents as to whether Reliability Options are a financial derivative, and the implications for compliance with derivative trading regulations, consequential costs of participation and impact on the forward trading of energy.

Another respondent highlighted that one of the largest deficiencies of the current SEM market is the futures/CfD market. An efficient futures market, more than any other section of the market, would foster greater supply side competition and ultimately better value for the final consumer. Given the uncertainty surrounding the details of the Reliability Options there is a potential for the Reliability Options to negatively impact on the working of the CfD/futures market in the new I-SEM.

Market Power Mitigation

A final concern raised by the respondents was the potential for market power under the proposed quantity based Reliability Options. Respondents raised the potential of a dominant player being able to manipulate Reliability Option Auctions, and that these issues had been down played in the Draft Decision Document. As a result of the potential for the exercise of market power many respondents stated that the CRM is likely to require regulatory intervention to 'bound' price responsiveness. This could take the form of a price collar/floor or a price stability mechanism. Respondents highlighted that measures such as these (e.g. floor prices and rules on minimum competition levels) have been used by the New England ISO to regulate offers within its Reliability Option CRM.

There was some confusion between the Draft Decision Paper which stated that Reliability Options are market-based, whereas the Initial Impact Assessment stated that regulatory intervention is needed to restrain market power. This was given as an example of a lack of consistency as to what is meant by market-based.

One respondent also had a concern that market power may be compounded by the use of the Day-Ahead Price as the reference price. Using the DAM reference price would not fully reflect the true need for flexible plant and short term Security of Supply, as a result of the 'non-mandatory' nature of the market and because of a EUPHEMIA price cap:

In regard to the 'non mandatory' issue it was stated that this may lead to an import bias on the interconnectors at the Day-Ahead stage. This would create a risk that congestion on the Interconnectors might prevent Great Britain based holders of Reliability Options from participating in the market schedule whenever the day-ahead reference price goes above the strike price (which may be in breach of European state -aid guidelines).

In terms of the EUPHEMIA price cap, a respondent stated that this issue may impact on the ability of the quantity based Reliability Option being able to solve the missing money issue. As a result at least one respondent requested testing is carried out prior to a final decision being made.

4.2.3 SEM COMMITTEE RESPONSE

General

The SEM Committee welcomes the engagement of market participants on the form of the CRM including the further research carried out in the preparation of consultation responses. The final Decision Paper, Impact Assessment and this document are intended to provide sufficient details on the proposed CRM for the HLD phase of the Market Integration Project. Additional detail on specific aspects of the proposed CRM will be further explored in the detailed design phase.

International Experience

A number of responses highlighted relevant international experience from existing Reliability Option schemes in New England and Colombia. Some respondents also noted that GB had decided to introduce capacity auctions rather than Reliability Options for the quantity-based CRM.

In its May 2013 Impact Assessment on the choice of a CRM, DECC set out that its reasons for choosing a Capacity Auctions approach (the Administrative Capacity Market) were that it would be more cost-effective, with less change to existing arrangements and lower risks for generators. It would be more likely to ensure security of supply in the absence of cash out reform, which would sharpen short-term price signals. DECC was also concerned that the necessary liquid reference price would not be in place, pending action by Ofgem to improve market liquidity.

In that May 2013 Impact Assessment, DECC noted that with adequate reforms to the cash-out regime, a Reliability Market could prove to be more cost-effective. Demand would be protected from price spikes and generators would not need to factor in scarcity rents when considering investments, meaning lower risks. This would potentially result in a reduction in

costs faced by consumers. Indeed, paragraph 8.3 of the May 2013 Impact Assessment noted that if cash-out was fully reformed, DECC would consider transitioning to Reliability Options. In addition, the liquidity in the GB DAM has improved substantially since the decision was taken on the form of the CRM.

The SEM Committee is keen to ensure that lessons from international experience are applied to the design of Reliability Options in the I-SEM. It is also important though to recognise the specific context of the application of the scheme and how this differs between jurisdictions.

In particular, in the I-SEM, the energy trading arrangements are intended to provide a highly liquid DAM (unlike the DAM in BETTA when DECC adopted the Capacity Market design in 2012) with Reliability Options being introduced as part of a package with an imbalance pricing regime. Furthermore, the absence of legacy forward physical contracts in the SEM (i.e. contracts that would allow self-scheduling) mean that there would not be the same transition costs for a CRM based on reliability options as were identified for BETTA, where there would need to be extensive rewriting of these contracts.

Furthermore, the CRM is only part of a package of measures to support the delivery of adequate capacity and flexibility in the future in the All-Island Market. Other important parts of the package include the revised energy trading arrangements and the DS3 programme.

Physical Back-Up and Additional Penalties

A the number of respondents are in favour of a physical back-up to the Reliability Option and having considered the issue further, the SEM Committee agrees that a requirement for physical capacity underlying the option is essential to ensure system adequacy as well as solving the 'missing money' problem. In both the current reliability option designs in New England and Colombia, the financial option is similarly backed by physical capacity.

Without such a requirement, the market value of reliability options would simply reflect the expected value of Reliability Option payments (i.e. if energy prices are above the contract strike price), and any missing money in the energy market would be mirrored in the capacity market. With a requirement for physical capability, the pricing of the options will reflect scarcity in capacity, plus any expected payments under the Reliability Option.

A further aspect of the design of Reliability Options is whether a physical penalty for non-delivery will be introduced in addition to the call option. At this stage no view has been taken on whether an additional physical penalty will be required. This will be considered at the detailed design phase and will be influenced by a number of factors including interactions between the DAM, IDM and BAM and experience from other markets.

However, the case for penalties must be considered in the context of their implementation. New England, for example, has had particular reliability problems as a result of gas-fired generators not being able to obtain firm access to the gas transportation system and

therefore they were not able to deliver gas during stress events. Introducing a penalty scheme, on top of peak energy rents, was perceived to be the way to address the problem.

The New England ISO is implementing a physical penalty for non-delivery as part of the next round of its capacity market. NE ISO will ultimately move to a maximum penalty of \$5,000/MWh during stress periods. There is a glidepath that will see the penalty set at \$2,000/MWh in the next commitment period. This penalty will be accompanied with changes to the scheme which will allow participants to pay back more in penalties than they have received in option fees.

The detailed definition of the requirement for physical back-up in the I-SEM reliability option (including timing, the qualification criteria and any consequences of failing to meet or over-delivering on the requirements) are important design features and will be addressed in the detailed design stage of the project.

Perceived Discrimination against Renewable Generation and Demand-Side Units

All quantity based schemes include consequences in case of non-delivery of service, which may be defined in terms of availability of (peak) energy delivery. The philosophy behind a quantity based CRM is that the provider receives an upfront payment, whilst undertaking a firm obligation to deliver (or be available to deliver) energy when needed. This means that sellers of reliability options will need to balance their revenue from capacity payments against the potential liabilities.

In principle, a capacity mechanism is aimed at delivering a certain security standard. Different providers, whether generation or demand-side units, have different availability profiles. Therefore, the overall remuneration arrangements should reward those units which can make a consistent contribution to system reliability by delivering firm energy over critical periods.

Many studies have confirmed that wind has a positive capacity credit and contributes to system reliability. Indeed, this topic is covered in some detail in the Generation Capacity Studies published by EirGrid/SONI including consideration of alternative means of calculating the capacity credit for wind. However, this capacity credit diminishes as the relative wind installed capacity on the system increases and is materially less than conventional technologies. This is no more than a reflection that system stress events tend to occur when wind output is at low levels.

Participants with variable generation will be in a position to participate in the capacity auctions and be remunerated for their contribution in line with all other generators. This means that wind will be able to participate in the reliability options scheme to the extent it contributes reliably to the security of the system.

Under reliability options, a wind generator that is not available faces the same financial consequences as thermal generators that fail to produce. Both technologies are subject to the same financial penalty in the case that the reference price is above the strike price.

Therefore, we do not consider that reliability options unfairly or unfairly discriminate against one set of market participants or technologies in favour of another. This point is considered in a recent World Bank Study on Wind Power in Colombia which discussed the participation of wind in the Colombian reliability market:

‘Importantly for wind power, the call option portion of the firm energy product is the same as the call option for thermal resources. During scarcity periods in which the spot price exceeds the scarcity price the wind resource has an obligation to generate energy over the day consistent with the resource’s firm energy rating....as a variable resource the energy output of the unit will surely differ from the obligation on any particular day but over the course of many days the unit should produce an amount roughly equal to its firm energy rating...and if it does so then its net payment for deviations would be approximately zero’⁹

There are three potential streams of revenue for wind generation associated with the delivery in periods of system stress. The detailed design must consider these issues in the round. The first is the potential sale of Reliability Options, which must be balanced against the expected costs of the Reliability Option repayments and any penalties for unavailability, if they exist and are applicable to variable generation. The second is the capture of peak energy prices for volumes uncontracted by the Reliability Option, or for energy prices below the Reliability Option strike price. The third is potentially the payment for over-delivery at critical periods against the contracted volumes – which will depend on the detailed arrangements. A wind (or other variable) generator, like any other market participant will have to decide which revenue stream is most advantageous to them, and participate accordingly in each market.

Secondary trading of obligations can also help long term commitments to be passed on to participants which are less able to give certainty in advance. This may include demand side as well as interconnection, covering plants with unexpected availability. For example, the New England Reliability Option scheme has monthly reconfiguration auctions that facilitate secondary trading closer to delivery time. Any secondary trading arrangements must be transparent, cost-effective and provide adequate mitigation against the exercise of market power.

Demand-side units are important in delivering flexibility to the system and can be a cost-effective solution in ensuring security of supply. Appropriate mechanisms will be in place for facilitating the participation of demand-side units in both the energy markets and Reliability Option scheme. These issues will be addressed in the detailed design phase. As one example, in the New England Reliability Option scheme, demand-side units (successfully) participate in the Reliability Options scheme. In that particular case, demand-side units who deliver capacity in line with their obligations are exempt from paying back the peak energy rent.

⁹ Vergara, W., Alejandro Deeb, Natsuko Toba, Peter Cramton and Irene Leino Wind Energy in Colombia: A Framework for Market Entry (World Bank, July 2010).

In summary, there are a number of ways of ensuring equitable treatment of different capacity resources in terms of access to the CRM scheme for the capacity that they can provide to the system. The SEM Committee has a statutory duty not to unfairly discriminate between licence holders, inherent in which is the recognition that under certain circumstances it is necessary to apply different rules to different groups depending on their technical characteristics (such as apply a capacity credit to variable generation in assessing its contribution to system reliability). The SEM Committee looks forward to working with market participants to deliver the best set of arrangements for this in the I-SEM, drawing on international experience but also reflecting the particular circumstances of the all-island market, including the issues that Reliability Options are intended to solve.

Interaction with the forward market

As described in Section 2.1.3, a well-functioning forward market is an important element of a well-functioning set of energy trading arrangements. Concerns have been expressed by some respondents that introduction of reliability options will undermine financial forward trading by making it more complex.

The issue identified is that under a conventional CFD contract, the seller is obliged to pay (or receive) the difference between the CFD reference price and the CFD strike price. If the seller holds a Reliability Option obligation, then they are obliged to pay any (positive) difference between the Reliability Option reference price and the RO strike price. If they have sold both contracts (assuming that the RO strike price is higher than the CfD and the same reference market is chosen) then if the market reference price exceeds the Reliability Option strike price then they are obliged to make repayments twice.

The SEM Committee recognises the issue identified by respondents, as well as the importance of ensuring that market participants have confidence in the forward trading arrangements. However, it would appear that this is an issue that can be addressed within the energy or capacity contract.

The instances where this could pose significant problems are where long term contracts are in place, which do not easily lend themselves to changes. This was also one issue highlighted by DECC in their impact assessment of Reliability Options for GB. The main form of long term contracts currently in the SEM are PSO underwritten ones such as renewables support in both jurisdictions. It is not clear that there is an adverse interaction between these but any issues will be capable of being addressed. Any new directed or non-directed contracts will need to take into account the features of the Reliability Options to prevent any double payments.

This issue will be further considered as part of the detailed design phase.

Market power mitigation

The Draft Decision Paper acknowledges the importance of market power mitigation

measures in the CRM. The details of the strategy for dealing with market power will be worked out in the detailed design phase.

The potential for market power exertion has been put forward by many respondents including those for and against Reliability Options. The SEM Committee cannot at this stage state what the detailed market power mitigation measures in the I-SEM CRM will be but is now confirming its commitment to ensuring that the mechanism implemented will be robust to market power exertion concerns.

The SEM Committee is cognisant of the fact that the I-SEM capacity market is not the only market where market power is a concern. Therefore, it is illustrative to look at other quantity based CRMs and to examine how market power is dealt with in these mechanisms. As part of this process the RAs have been in contact with DECC, the designers of the GB CRM and the New England ISO, the developers and operators of the New England Forward Capacity Market to identify how they approached the issue of market power, and what lessons can be learned for the I-SEM.

There are a number of choices available for mitigating market power in quantity based CRMs. For example, DECC will employ the following measures;

- Market Abuse Obligations
- Use of a sloping demand curve
- High Level Participation Requirements
- Restrictions on Offerings
- Identification of pivotal supplier(s) and bid mitigation measures

Annex 4 Contains a detailed description of the market power mitigation measures incorporated in the GB Capacity mechanism.

The New England Scheme also has a number of measures inherent in its implementation that act to address market power concerns. A key plank of these measures is the analysis of the De-List bids submitted by auction participants. De-list Bids set the threshold at which plants can withdraw their capacity in the NE scheme. These bids, above a certain threshold, are examined by the ISO as part of auction qualification.

In summary, evidence suggests that while market power is a concern with quantity based schemes in other market besides Ireland and Northern Ireland it is a concern that can be adequately addressed through mitigation measures and there is significant evidence from other markets that market power mitigation measures have been effective in volume based capacity markets. Indeed, market power concerns are not just confined to quantity based schemes. The current capacity mechanism in the SEM has design features which are designed to mitigate market power. These include the inclusion of a flattening power factor which smooth payments and also the payment of a large amount of the capacity pot ex-ante. These features reduce the incentives to withdraw capacity to increase capacity prices in particular periods.

5 DECISION-MAKING PROCESS

This section provides a summary of the responses received in regard to the decision-making process so far. It is structured as follows:

- Lessons from the SEM
- Overall Initial Impact Assessment;
- Initial Impact Assessment of the ETA;
- Initial Impact Assessment of the CRM;

5.1 LESSONS LEARNT FROM THE SEM

5.1.1 SUMMARY OF RESPONSES

A number of responses addressed lessons learnt from the SEM and areas of the current market design that they stated should continue. Most of these points have been discussed in the earlier sections and so the responses highlighted in this section are more generic and relate to preferences for the Detailed Design Phase. Those who did respond in this regard were generally positive in terms of the performance of the SEM.

One respondent stated that the SEM has seen significant improvements in security of supply as evidenced in the large margin of spare supply, whilst acknowledging that some of the improvement is due to reduced demand. In addition, environmental sustainability performance has improved with the rollout of significant renewable electricity generation capacity.

A second respondent highlighted that compared to international peer markets the SEM has a number of positives. However it has a number of administrative weaknesses that will need to be addressed in the detail design of the I-SEM. The issues highlighted by the respondent are:

- Settlement times - 2-5 weeks in SEM versus next business day in other markets
- Speed and format of data publication
- Accuracy and timeliness of volume and price publication
- Inefficient bilateral contracting and clearing process in the CfD markets
- Needlessly high collateralization in PSO and other CfD markets.

5.1.2 SEM COMMITTEE RESPONSE

The SEM Committee welcomes the acknowledgement from market participants of the success of the SEM and is determined to build on these successes in the design and implementation of the I-SEM.

At the same time, the I-SEM design and implementation will take account of the lessons learnt from the SEM as set out in the Draft Decision Paper for the I-SEM HLD. This will include dealing with the opportunities posed by greater market integration as well as delivering a secure system with high levels of variable renewable generation.

As part of the detailed design and implementation phase, this will include ensuring that administrative processes are in line with best practice, whilst delivering value for money in a small market like the SEM.

5.2 OVERALL INITIAL IMPACT ASSESSMENT

5.2.1 SUMMARY OF RESPONSES

Only a limited number of responses were received from respondents in relation to the specific details of the Initial Impact Assessment.

A number of respondents stated that the SEM Committee should carry out a more robust overall Cost Benefit Analysis (CBA) to ensure that the ultimate decisions are in the best interests of the consumer and market participants and deliver against their stated objectives. Another respondent stated that an individual CBA should be completed for each element of the Detail Design that differs from the current SEM.

One respondent provided an alternative set of assessment criteria that it stated should have been used in the qualitative assessment.

Another respondent stated that a transparent and robust methodology is essential to ensure that the impact assessment can be communicated to stakeholders affected by the decision. This respondent noted that the assessment time frame can have a significant impact on the overall outcome of a quantitative analysis and the rationale for the choice of 14 years for the I-SEM Impact assessment is not obvious from the information currently available.

This same respondent noted that the scenarios presented include levels of variable non-synchronous generation that will pose significant operational challenges. Unless there is a commensurate investment in necessary performance capability, similar to that presented throughout the DS3 System Services review, these scenarios may not be feasible. A scenario considering an average contribution from renewable generation of 40%, and a DS3 System Services decision similar to EirGrid's recommendation, may improve the robustness of the impact assessment.

This respondent also noted that it was important that the CBA only considered the benefits created by the market design, particularly where the costs of other related measures have not been considered – examples were given in relation to network investments, renewable support mechanisms, and delivery of system services.

Another respondent stated that no account had been taken of the impact on absolute priority dispatch. In addition, there was no examination of the impact on different classes of participants, such as Variable Price Taker plant and of key associated rules, of intermediaries and of tie-breaks.

Another respondent argued that sensitivities should have been tested around the direction

of interconnector flow. The respondent stated that due to the uncertainty in the UK energy market arrangements it would have been sensible to include some economic assessment of alternative scenarios in which exports from I-SEM to GB turned out to be much more substantial.

A respondent also stated that in relation to the SEM Interconnectors, it is uncertain if all the benefits of coupling will be realised due to the relative size of I-SEM relative to BETTA which results in physical ramp rate limitations. This may result in physical flows being in the opposite direction to market flows. The effect would be increased redispatch volumes and costs to consumers in I-SEM. This respondent noted that across Europe it is normal for ramp rate limitations to be set on interconnectors.

5.2.2 SEM COMMITTEE RESPONSE

The SEM Committee set out its decision on the criteria that would be used to assess the I-SEM HLD in the February 2013 'Next Steps' Decision Paper. These criteria had been consulted upon and the results of that consultation were taken into account in the SEM Committee decision. The decisions and recommendations set out in the Next Steps Decision paper were subsequently endorsed by DCENR and DETI.

The assessment criteria used in the Impact Assessment (IA) has therefore been established through a robust process and reflects the whole range of SEM Committee objectives. Therefore, to revise the assessment criteria as suggested by one respondent would not be appropriate.

In the 'Next Steps' Decision Paper, the SEM Committee expressed its commitment to the retention of the principle of absolute priority dispatch and this has therefore been treated as an absolute requirement for any compliant design. Although the details of how this will be implemented will be covered in the detailed design phase, the SEM Committee is content that the HLD for the I-SEM is consistent with the principle of absolute priority dispatch. Similarly, the tie-break provisions will be implemented in the I-SEM as part of the detailed design phase. The Final Decision Paper sets out the SEM Committee decision that intermediaries will be accommodated in the I-SEM.

The focus of the CBA has been on the overall welfare benefits of the I-SEM Design choices. In the Final Impact Assessment (IA) the SEM Committee has presented further distributional analysis on the relative impacts on consumers and producers.

With respect to further distributional analysis, such as the impact on Variable Price Takers, it should be noted that one of the primary qualitative assessment criteria is 'environmental'. This focuses on identifying the impacts of the revised market arrangements on the facilitation of renewable generation. In addition, the Impact Assessment reports curtailment levels under the different sensitivities for interconnector flows. From a monetary perspective the impact on Variable Price Takers will differ considerably by size, type of support scheme, trading patterns, as well as a number of detailed market design features to be defined in the detailed design phase. Assumptions in these areas would

significantly affect the comparison of the impact of different options on variable price takers. Therefore, it was not practical to carry out such a detailed quantitative distributional analysis of this subset of market participants at this stage.

Given the nature of the change involved in developing a revised HLD, the SEM Committee does not consider it appropriate to carry out a CBA of each individual change. The HLD of the I-SEM should be considered as an overall and coherent set of arrangements rather than a set of piecemeal changes. The assessment of any one feature is necessarily affected by the choices made elsewhere in the design.

In addition, particularly in the Impact Assessment, the difficulty of objectively modeling different sets of energy trading arrangements should be noted. This becomes even more difficult when considering just one individual element of the arrangements as assumptions would need to be made about other aspects of the market arrangements that could skew the analysis. This can lead to a focus on quantifying costs of implementation and not quantifying possible benefits which could be several orders of magnitude larger.

The Final IA has separately quantified the benefits of the energy trading arrangements and CRM, as their effects are largely separable from a modeling perspective. The qualitative assessment, in particular for the form of the explicit CRM, does consider the interactions between the proposed energy trading arrangements and the proposed CRM – e.g. in terms of high day-ahead liquidity.

A transparent and robust methodology is important in communicating the impact assessment to stakeholders. This is particularly challenging in this instance given the complexity and scope of the market design changes under consideration. The Impact Assessment describes the overall approach in terms of the balance between qualitative assessment, quantitative assessment and CBA. It then provides more details on the approach to the CBA, both in terms of the estimation of differences in implementation and operating costs, and in the wholesale market modeling.

The definition of the time horizon for a CBA is also a challenging question, particularly when there are upfront investment costs – e.g. in systems. For the CBA presented in the Impact Assessment, costs and benefits were quantified out to 2030. The endpoint of 2030 was used as this represents a key milestone date in European energy policy, and projecting scenarios beyond that date become increasingly uncertain. International experience suggests that a 14 year assessment period seems reasonable for a new set of market arrangements and its associated systems.

The wholesale market modeling has been carried out using Pöyry's wholesale electricity market model. It should be noted that this is a model extensively used for market analysis in Ireland, GB and in Europe more widely. .

The SEM Committee recognises the desire for additional scenarios that inevitably accompanies any quantitative analysis. However this must be balanced against the practical constraints on such analysis, including effectively communicating the results to

stakeholders. This is particularly the case where significant weighting is placed on the qualitative assessment. In particular, the respondent asked the question about the impact of modeling efficient flows with an assumption of greater exports from GB to the I-SEM.

The interconnector flow sensitivities tested in the modelling identify that there is significant overall welfare loss for the all-island market from the reduction in the efficiency of scheduled interconnector flows. In addition, there is a significant increase in curtailment. The SEM Committee is confident that this pattern of results would be repeated in scenarios where there were more flows from the all-island market to the GB market. While the SEM Committee is fully aware of its primary objective to protect the interests of consumers this does not mean a reduction of prices should be achieved at the expense of all other objectives that might impact on consumers in the longer term. Inefficient interconnector flows can be seen as the result of a distortion to trade. In the case where the all-island market is a net exporter, a distortion to trade that reduces the level of net exports could reduce wholesale prices. However, it represents a barrier to competition, distorting the merit order against generation in the all-island market and would run contrary to the SEM Committee primary objective of promoting competition and the thrust of the EU policy to create a single, competitive pan-European energy market.

In both base cases used for the modelling, 40% average generation from renewables has been assumed for 2020. This is in line with stated policy objectives in Ireland and Northern Ireland. For the purposes of this Impact Assessment, it is reasonable to assume that policies and tools will be in place to support continued growth in renewables beyond 2020.

It is important that the Impact Assessment only reflects the direct costs and benefits associated with the options under consideration. In this regard, it is important to note that the CBA was carried out on an unconstrained basis, with no differentiation between the different options in terms of network investments and the delivery of system services. In this regard, the interconnector modeling was not constrained by ramp rates as these would need to be agreed as part of the implementation phase. Interconnector ramp rate restrictions often relate to the constraints on the wider system rather than the physical capability of the interconnection, particularly for EWIC. The loss factors on the interconnectors were however included in the modelling as this affects the economic arbitrage between the SEM and GB markets.

The renewable build is assumed to be the same for each scenario so that the direct costs of renewable build are the same in all scenarios – except in the one sensitivity which tests the impact of a higher cost of capital for variable renewable generation. Finally, where new interconnection is built under a particular scenario, the costs of building and operating this interconnector have been included in the comparative analysis of costs and benefits, which is the appropriate treatment.

5.3 INITIAL IMPACT ASSESSMENT OF ENERGY TRADING ARRANGEMENTS

5.3.1 SUMMARY OF RESPONSES

In regard to the quantitative assessment one respondent stated that the non market costs of the energy trading arrangements were high. Their view was that minimally-compliant market arrangements could be put in place for substantially less than the level presented in the Initial Impact Assessment. As a result additional systems costs should be properly quantified in the full impact analysis, alongside the expected efficiency benefits.

In contrast, another respondent stated that the estimated costs for market participants were too low.

Another respondent noted that a centrally developed solution for the non-market costs would be most efficient given the anticipated costs involved.

One respondent stated that the qualitative appraisal did not provide an objective or balanced support for the Draft Decision and that the gaps in the design of the chosen energy trading arrangements could significantly alter the appraisal presented in the Initial Impact Assessment. This respondent also criticised the reliance on EUPHEMIA, given the uncertainty surrounding how this will work in the I-SEM, and highlighted a lack of qualitative assessment of the possible increase in scheduling risk as a result of the new arrangements and use of EUPHEMIA.

Some detailed comments from this respondent are included below:

- The assessment was presented as if Option 3 had already been selected rather than being used to select Option3.
- The assessment assumes EUPHEMIA will deliver efficient Day-Ahead Market schedules but doesn't give other options the benefit of doubt.
- The Assessment is overly focused on the Day Ahead Market.
- Failure to keep Bidding Code of Practice in Options 1 and 3 should count in favour of Options 2 and 4 because no detail is provided on how market power mitigation concerns will be solved in Option 3.
- There is contradiction in the arguments. In one section Option 3 is praised as being a good reference price for forward trading but elsewhere in the draft decision its says that Option 3 would need incentives for DAM participation.
- The competition assessment is not based on an understanding of competition policy which is intended to ensure institutions support producer competition that benefits consumers. Instead appraisal is based on routes to market and liquidity.

5.3.2 SEM COMMITTEE RESPONSE

The SEM Committee is mindful of the need to ensure the cost-effective implementation of the I-SEM HLD. In this regard, it notes that the focus of the CBA is on differences in costs and benefits between the different options and this focus has been sharpened in the Final IA.

The Initial IA highlighted the importance of common implementation and operating costs across the different options for energy trading. For example, around half of the cost relates to ongoing staff costs for market participants to participate in intraday energy trading. Given that continuous intraday trading is at the heart of the Target Model this would appear to be a cost related to compliance which is an absolute requirement across all considered options rather than particular market design. The Decision on the HLD has recognised the importance of aggregators and intermediaries in helping to manage these costs particularly for smaller players.

Respondents who provided comments on the estimated implementation and operating costs did not provide any details of alternative estimates. In addition, the respondent who commented that market participation costs were too low did not state whether that was for a particular option, which is of particular relevance for the CBA, or for the common costs, which would be of particular interest for the detailed design and implementation stage. Hence, we were unable to update this component of the assessment.

The SEM Committee notes that any qualitative assessment may be charged with being subjective. However the qualitative assessment criteria have been equally applied and have been subject to extensive consultation. It is therefore not unexpected that the Impact Assessment is seen as providing a favourable assessment of the chosen option given that the objective was to choose something that best met our criteria.

Selection of Energy Trading Option

As noted above, one respondent suggested that Option 3 was selected prior to the assessment process. The same respondent also suggested that there was insufficient detail in the Consultation Paper to make a decision.

The process being engaged in is the same approach that has been applied in the past when the current SEM was designed. In light of this there will invariably be aspects of the market workings that will be decided in the detailed design phase. Indeed, some respondents have commented that certain decisions should be left to the detailed design phase.

The consultancy report that accompanied one respondent's submission stated that the final decision should include;

Detailed descriptions of each market design which clearly identify (1) all the features that determine real world outcomes, and (2) all the features that distinguish one design from another

This is done insofar as it is possible at the High Level Design stage in that there is a description of the four options in the consultation paper and a description of the chosen option in the Draft Decision Paper. Market participants in general appear to have understood the four options overall although there have been detailed questions that would need to be worked out at the detailed design phase

The qualitative assessment summarised the reasons why Option 3 was chosen. Amongst other things, there was a concern that cross border trading would be less efficient in Options 2 and Options 4 which relied on pool based balancing arrangements and hence led to more power being traded in real time without allowing for the ability of market participants to respond to changes in prices in other bidding zones.

The key difference between Option 1 and Option 3 relates to the decisions on self-versus central scheduling and whether forwards contracts are physical or financial in nature. Outside of this distinction, much of the difference between the two options was not of the same order of magnitude as the dispatch model choice and related to things such as unit versus portfolio bidding. In general, the design of the DAM, IDM and BAM under Option 1 and Option 3 are similar with key differences being whether they are voluntary or not.

The SEM Committee considered the central versus decentralised arrangements issue as part of this consultation process and ultimately decided, with the support of the vast majority of participants, that a centralised philosophy is most appropriate for I-SEM. This has been discussed further in earlier sections. It is worth adding that the balancing market under Options 1 and 3 would have been very similar, with the primary difference coming from the outcome of the DAM and the starting point of dispatch.

The SEM Committee is committed to the delivery of a highly liquid DA market as part of the implementation of the I-SEM. At the same time, a robust day-ahead market alone is not sufficient to deliver an efficient implementation of the new HLD. This point is discussed further in Section 2.2.3. This document addresses the question of scheduling risk in Section 2.1.3 and use of EUPHEMIA to deliver an efficient day-ahead schedule in Section 2.2.3.

Effective market power mitigation measures will be a key part of the I-SEM Detailed Design. In addition, it is important that in the HLD, institutions, or perhaps more widely arrangements, are in place to support effective competition. The respondent is not specific about which institutions they see as particularly important in facilitating effective competition. The ability to mitigate and promote competition was one of the reasons for choosing option 3 over option 1, where market power mitigation would have been more problematic.

Arrangements facilitating competition include support for liquid markets with a variety of access for market participants. With this in mind, a number of features of the HLD have been selected for the purpose of building in measures that would naturally help to support competition and mitigate market power. This includes transparent unit-based trading in centralised exclusive market places to ensure that all volumes have to be brought to market. In addition, there is support for forward market liquidity, a requirement for mandatory participation in the Balancing Mechanism, and mechanisms to ensure that producers of all technologies and sizes can access the market.

Whichever HLD is used for the energy trading arrangements for the I-SEM, the implementation of the Target Model raises challenges for the simple retention of the Bidding Code of Practice in its present form, particularly in relation to its application in

trading over a number of different timeframes. Therefore, the SEM Committee regards it as simplistic simply to assume that the use of the BCoP in a pool in one timeframe is sufficient market mitigation overall.

Further in this regard, the SEM Committee notes the concern of respondents that the BCoP has not been effective in mitigating market power in the forward timeframe. Further, the respondent who stated that the retention of the BCOP should be favourable for the assessment of Option 2 did not provide any indication of how it thought that the BCOP would operate in the context of a net pool.

5.4 INITIAL IMPACT ASSESSMENT OF CRM

5.4.1 SUMMARY OF RESPONSES

Very few respondents provided comments on the details of the Initial Impact Assessment. One respondent stated that the appraisal assigned to each CRM according to whether it is price based or quantity based was spurious. They also noted that the Initial Impact Assessment repeatedly describes Reliability Options as “market based”, and marks down other schemes for requiring regulatory interventions. The respondent stated that this is incorrect and overlooks practical examples and academic literature on the design of Reliability Options.

Some detailed comments from this respondent are included below:

- Market power mitigation is more necessary in the chosen CRM because value of capacity is more concentrated in peak periods
- Market power cannot affect level of payments under the current capacity payments scheme, but this is not recognised as such in the overall scoring, particularly given market power mitigation rules needed for a quantity based CRM
- The need for market power mitigation as a result of Reliability Options is discussed in the Initial Impact Assessment but is not reflected in the Draft Decision Paper.
- Interconnectors may not be able to help in stress periods as a result of the penalties in the GB market
- ISO-New England requires rules on minimum offer price, the need for new competition, and resource specific price caps and this would need to be considered for the I-SEM market.

A number of respondents stated that the Draft Decision Paper and Initial Impact Assessment did not provide enough information for participants to comment on the possible design of the CRM. A couple of responses highlighted that more robust justification for the particular choice of CRM in the Final Impact Analysis would be needed. Especially as the Initial Impact assessment seemed to indicate that other options for the CRM appeared to offer substantially greater potential for end-user cost savings.

5.4.2 SEM COMMITTEE RESPONSE

Elsewhere in this document and in the Impact Assessment, the SEM Committee has set out its view on the relative merits of price-based and quantity-based CRMs.

The key difference between the two approaches is the scope for competition to affect the level of payments by consumers. Regulatory intervention on its own does not mean that a scheme can no longer be described as market-based and it was never the intention of the SEM Committee to imply that Regulatory intervention would not take place if necessary to mitigate market power. Most, if not all, electricity markets across the world have forms of regulatory intervention, particularly in relation to market power mitigation. For example, in the SEM today, there are restrictions on bidding into a mandatory spot market and requirements to offer forward contracts but the SEM would still be described as being a market-based approach.

The flip-side of ensuring that consumers can benefit from competitive pressures is the need to ensure that there is an effective framework for competition, including specific market power mitigation measures where necessary. There are examples of these to be derived from international experience in a range of quantity-based CRMs.

The point made regarding the incentives that may be in place under the GB CRM to deliver electricity to GB and not to neighbouring markets in stress periods in GB has been noted. However, these incentives reflect the design of the GB CRM rather the design of the CRM design in the I-SEM. This increases the importance of effective cross-border participation in the CRM, backed by a commitment to deliver when required by circumstances in the All-Island Market.

The CRM approaches have been presented in sufficient detail for the HLD phase of the Market Integration Project, with some clear distinctions behind the approaches. There is significant further work to be done in the detailed design phase but that is to be expected as part of the design and implementation of a major market reform.

The Initial Impact Assessment noted the strong performance of the short-term price-based CRM in the modeling results. That document also explained the context for the interpretation of those results and the importance of balancing the quantitative results against the qualitative assessment.

6 DELIVERY PLAN

This section provides a summary of the issues relating to the detailed design phase, lessons learnt from the current SEM market and views on the process going forward to implement the Detailed Design. Specifically:

- Overall process going forward;
- Detailed Design Phase – Energy Trading Arrangements; and
- Detailed Design Phase – Capacity Remuneration Mechanism.

6.1 OVERALL PROCESS GOING FORWARD

6.1.1 SUMMARY OF RESPONSES

A number of responses were received regarding the process going forward from the HLD phase to the Detailed Design phase and through to implementation. The majority of responses covering this topic wanted additional detail on the project plan and a programme timeline be published by the SEM Committee immediately.

One respondent stated concern that given the current implementation timings, the Regulatory Authorities will be forced to compress the most important design phase of the project into a timeframe that is shorter than is required. Substantive decisions in areas such as liquidity, market power mitigation, testing of EUPHEMIA and access to real time demand data for energy trading are still required.

Another respondent urged the SEM Committee to carefully review the original timetable for the ISEM project as published in February 2013 and consider the continued feasibility of this given the magnitude and nature of the work that remains to be completed. The respondent stated that it is essential that an updated project plan is published without delay allocating sufficient time for robust and inclusive EUPHEMIA testing, genuine industry consultation in detailed design and participant IT procurement and readiness. This respondent stated that due to the delays in delivering the Intraday market across Europe the SEM Committee could consider a more measured approach in terms of overall project delivery timeframe and one in which all issues can be discussed.

Another respondent stated that it is crucially important to have a clearly defined transition date (e.g. 1st January 2017) to allow for planning and an orderly transition to the new market design. Market participants are now looking to trade on a forward basis out to end of 2016, and there is a pressing need for certainty around market regime in 2016 in particular.

Another respondent noted that a phased transition should be considered with the introduction of energy market measures first and the revised Capacity Remuneration Mechanism introduced later within a 2 - 3 year period.

6.1.2 SEM COMMITTEE RESPONSE

The SEM Committee acknowledges the importance of a clear forward-looking work programme for the successful implementation of the new I-SEM arrangements. Good communication with stakeholders on progress against a realistic and transparent plan of work will help to ensure confidence in the arrangements and also facilitate stakeholder engagement. Both of these will be vital to the successful delivery of the I-SEM arrangements.

Alongside the final decision on the HLD, the SEM Committee has published more information on the updated programme for delivery of the I-SEM. This will allow sufficient time for discussion with industry on the substantive issues to be addressed in the detailed design phase as well as system procurement, testing and readiness – for central systems and for market participants.

The SEM Committee recognises the importance of a clearly defined implementation date, which will be signaled as part of the forward-looking work programme.

The SEM Committee views the HLD for the ETA and the CRM as an enduring overall package. As part of the detailed design phase, the need for any transitional arrangements, and any contingency arrangements will be reviewed.

6.2 DETAILED DESIGN PHASE – ENERGY TRADING ARRANGEMENT

6.2.1 SUMMARY OF RESPONSES

A number of respondents raised queries and clarification regarding the Detailed Design phase of the energy trading arrangements for the I-SEM. The majority of these points have been highlighted in the previous chapters in relation to the HLD. However a number of respondents raised issues in relation to the Detailed Design that have not yet been specifically addressed in this document. These issues include:

- Interaction with REFIT
- Treatment of de-minimis, intermediaries etc.
- Treatment of Curtailment
- Priority Dispatch

Interaction with REFIT

The Draft Decision paper stated that the Day Ahead Market price could be used as a reference price for the REFIT support scheme. However many respondents noted that by proposing the DAM price as a reference for the support schemes the SEM Committee is entering into a policy area it is neither responsible for nor competent in. Many of these respondents set out that the simple replacement of the SEM price with the day-ahead price may leave a hole in the funding under the REFIT scheme, creating a new 'missing money' problem.

However a small number of respondents stated that setting the reference price of REFIT to the DAM price would encourage more participation in the Day Ahead Market by renewable generators.

Treatment of de-minimis, intermediaries etc.

The respondents who discussed these issues stated that features of the SEM such as intermediaries, de minimis, negative demand, treatment of 'Trading Sites' and 'supplier lite' need to continue without interruption into the I-SEM in such a way that existing projects and support schemes are unaffected.

Treatment of Curtailment

Respondents asserted that the SEM Committee's proposed removal of compensation for curtailment is discriminatory, contrary to the EU Target Model, and causes a perverse incentive to curtail virtually free energy. As a result this proposal should be reconsidered during the detailed design phase.

Priority Dispatch

A number of respondents stated that there is a continued need for the SEM Committee to acknowledge its support for the retention of absolute Priority Dispatch. In the HLD Draft Decision, Priority Dispatch is listed along with treatment of losses and firm access as an example of existing SEM Committee policy. However a number of respondents wanted to highlight that priority dispatch, along with the other obligations listed in the RES Directive, is a legal requirement and this should be clearly stated in the decision.

Another respondent stated that the Proposed Draft Decision does not eliminate the need for countertrading for Priority Dispatch generation. While the design provides solutions for managing forecast errors in the Intraday market, it does not provide a solution for situations where the volume of wind cannot be accommodated due to system non-synchronous penetration, or similar, limitations.

6.2.2 SEM COMMITTEE RESPONSE

Interaction with REFIT

The SEM Committee agrees that the design of the renewable support schemes is outside its remit and does not form part of the Market Integration Project. The decisions on the design and operation of any renewable support schemes remain the responsibility of the relevant Government Departments.

The SEM Committee is ready to assist the Departments, where requested, with any review of how the renewable support schemes could operate under I-SEM. In this regard, the point made in the Draft Decision paper was that the design of the renewable support schemes could affect the incentives for market participants to trade in different timeframes.

Treatment of de-minimis, intermediaries etc.

In the Decision Paper the SEM Committee has stated that aggregation and intermediary arrangements will be possible under the I-SEM arrangements.

Both are different types of solutions for outsourcing of an individual unit's participation in the markets. The main difference is that an aggregator is allowed to net all the units within the aggregator and bid this into the market as one unit (the example in today's SEM is the Demand Side Unit – DSU). An intermediary will have to bid in the unit(s) that is controlled according to the normal rules for the relevant type of unit(s).

It could be possible to have a combination; i.e. that an intermediary also is allowed to aggregate all or some of its units. An aggregator of last resort would be one example of this.

The SEM Committee is confident that concepts such as de minimis, trading sites, negative demand and 'supplier lite' can continue within the I-SEM arrangements, and will be addressed during the detailed design phase.

Treatment of Curtailment

The SEM Committee notes the responses in relation to its previous and separate decision on compensation for curtailment. That decision was subject to extensive consultation at the time and is not being reviewed as part of the work on the design and implementation of the I-SEM.

Priority Dispatch

In the Decision Paper the SEM Committee has restated its position that there are a number of existing features of the market that it does not currently plan to revisit as part of the design and implementation of I-SEM. The SEM Committee acknowledges some of these features, such as the requirement for absolute priority dispatch, are required to comply with European legislation. At this stage the SEM Committee does not believe it is necessary to separately set out the same policy position on issues depending purely on their statutory basis.

In the 'Next Steps' Decision Paper, the SEM Committee stated that absolute Priority Dispatch will remain in place in the new market arrangements.

Even though Absolute Priority Dispatch means that any unit with this feature will be allowed to run, subject to system security measures by the TSO, it will still be treated as a Balance Responsible Unit. This means that if it has not traded itself into balance in the ex-ante markets, this unit will face the imbalance price for any deviation from its nominated schedule at the IDM Gate Closure (as any other unit in the market). Absolute Priority Dispatch does not have an effect on the imbalance settlement for these units or act as a relaxation of the requirement for Balance Responsibility.

Countertrading for Priority Dispatch generation will remain an important tool for the TSO in the I-SEM. The HLD should provide market signals and mechanisms to help accommodate high levels of wind generation, e.g. through changing interconnector flows in the IDM. This should help to reduce the level of countertrading needed. The TSO will still need to intervene in situations where the volume of wind cannot be accommodated for system limitations that cannot be recognised in market schedules.

6.3 DETAILED DESIGN PHASE – CAPACITY REMUNERATION MECHANISM

6.3.1 SUMMARY OF RESPONSES

A number of respondents raised queries and clarification regarding the Detailed Design phase of the Capacity Remuneration Mechanism for the I-SEM. The majority of these points have been highlighted in the previous sections but a number of respondents raised issues in relation to the Detailed Design that have not been specifically addressed earlier in this document. These issues included:

- Calculating the Strike Price
- Calculating the Reference Price
- Penalty Arrangements
- Eligibility
- Auction Rules
- Delivery time and contract length
- Secondary Trading
- Credit Cover and Collateral

Calculating the Strike Price

Respondents were unclear as to how the Strike Price would be calculated. One respondent stated that the mechanism for setting it has not been defined but is likely to be set by the Regulatory Authorities. More detail will be necessary in the Detailed Design Phase.

Another respondent noted that the strike price should be based on the bid price of all generators, including those generators who do not have Reliability Options. This will prevent the possibility of generators who do not receive a capacity payment pushing the reference price above the strike price.

Another respondent was concerned that multiple strike prices may lead to an overly complex set of arrangements.

Calculating the Reference Price

A number of respondents asked for clarification on how the reference price will be calculated. Respondents wanted measures to be put in place to ensure the reference price is appropriate, robust and liquid. Another respondent stated that consideration should be given to using the Day-Ahead Market price as the reference price for contracts in the CRM and REFIT to encourage liquidity in the DAM.

Penalty Arrangements

One respondent noted that an additional penalty for non-delivery, over and above the payment made when the reference price exceeds the spot price, would be too penal a regime and create another barrier to cross border participation.

Eligibility

One respondent stated that the eligibility rules should require that issuers of Reliability Options have a credible presence in the I-SEM or future source of physical power. It would be perverse to allow purely financial players to participate in a mechanism that aims to secure adequate physical capacity. Another respondent stated that plant older than 30 years should not be eligible to participate in the auctions, or should be severely de-rated. Auction eligibility should be related to the planned contractual capacity to ensure competitive tension and value for electricity customers.

Auction Rules

A number of respondents stated that there is not enough detail on how the auction is to be run or how such an auction will bring the optimum mix of capacity to the market. One respondent stated that if the auctions for Reliability Options occur with a 4-year lead-time consideration must be given to interim arrangements for capacity payments during this period.

One other respondent expressed concerns about the interaction between the Reliability Options and DS3. The respondent noted that new entrants bidding for Reliability Options will have to make assumptions/estimates of DS3 and energy payments in their bid prices. Different technologies will attract different amounts of revenue from DS3 due to their different levels of flexibility. Therefore consideration should be given to a joint DS3/RO auction for new entrants in order to discover the most cost-effective solution for different technologies.

Another respondent stated that there should be two auctions in Republic of Ireland; one for existing/enhanced plant and one for new entrants, and the same arrangements in Northern Ireland. Under this approach new entrant generators will be immune to the price depressing impacts of the existing incumbent generation fleet.

Delivery time and contract length

One respondent noted that the paper recognises that there will need to be a time lag of several years to allow new plant to be placed on the same footing as existing plant. However this time lag has implications for the setting of the strike price and the need for some form of linkage with the market price. The paper also recognises that new and existing plant may have different contract lengths for Reliability Options. For conventional generation units this is normal and acceptable, however for AGUs and DSUs the position is quite different.

Secondary Trading

One respondent stated that given the time lag of several years between the auction and the contract start date it is essential that a secondary market is developed for the trading of Reliability Options.

Credit cover and collateral

A number of respondents emphasised that increases in credit or working capital requirements are a significant burden on market participants and act as a barrier to new entry, discourage effective competition and therefore increase costs for I-SEM consumers.

Transitional arrangements

Respondents stated concerns with the transition from the current price based CRM to a quantity based CRM. One respondent noted that the nature of the change is so profound that some degree of regulatory stability is necessary. As a result a sufficient (e.g. 3-4 year) lead time for capacity auctions would be required in order for market participants to formulate a bidding strategy for the auctions. A firm Trading and Settlement Code and System Services regime will need to be in place.

Some respondents stated that the uncertainty surrounding interaction with DS3 may be addressed by having a transitional period. One respondent noted that maintaining the current CRM during a period of transition would allow the energy trading arrangements to bed in without including additional confusion. Another respondent stated that new entrants bidding for Reliability Options will have to make assumptions/estimates of DS3 revenues and energy payments in their bid prices, which will add additional complications during the transition to the new arrangements.

6.3.2 SEM COMMITTEE RESPONSE

The SEM Committee has carefully considered the responses received in relation to the need for physical backing of Reliability Options. In the Decision Paper the SEM Committee has set out its decision that Reliability Options should only be issued to parties with a credible current or future physical capability.

The SEM committee welcomes the engagement from respondents on the detailed design aspects of the CRM. It looks forward to working closely with the industry in the next phase of the project to address many of the issues that have been raised, such as:

- the mechanisms and inputs for calculating the strike price for an Reliability Option
- the reference price, noting the importance of a robust, appropriate and liquid market, such as the DAM in the I-SEM HLD
- the definition of physical capability, both current and future
- the definition of contract length and delivery timeframe
- the format, timing and frequency of auctions including market power mitigation

measures

- the interaction with the processes and timescales for the procurement of system services
- the application of additional penalty arrangements if any
- the requirements and processes for secondary trading.

The SEM Committee has set out its decision on the enduring HLD of the CRM. As part of the detailed design phase the SEM Committee will work with the industry to deliver any transitional or contingency arrangements where prudent to do so.

1 ANNEX: LIST OF RESPONDENTS

Responses to the consultation were received from the following stakeholders.

Respondent	Respondents endorsing IWEA
Activation Energy	Ballycurreen Windfarm
AES	Carrons Windfarm
Alan Mulcahy (Private Citizen)	EcoPower
Beam Wind Ltd	Gaelectric Developments
Bord Gais	Loughderryduff Windfarm, North West Wind Ltd
Bord na Mona	NI Renewables Industry Group
Brookfield	Nordex
Coillte	Rathnameneenagh Energy Ltd
CRES Community Renewable Energy Supply	Redwind Energy
Dalkea	Saorgus Energy
EirGrid	The Irish Infrastructure Fund
Electricity Association of Ireland	Wind Energy Direct
Electricity Exchange	Wind Prospect
ElectroRoute	Windsources Ltd
Energia	Respondents endorsing IWFA
ESB	ART Generation
ESRI	AWC Ltd
HG Capital Ltd	Ballybay Windfarm
IBEC	Ballycadden Windfarm
Indaver Ireland	Beal Na Blath Power Trading Limited
iPower	Bearna Gaoithe Teoranta
Irish Solar Energy Association	Carraigcannon Wind Farm Ltd (Enercon)
Irish Wind Farmers Association	Carrownaweelaun Energy Ltd
IWEA	Collon Wind Power
Joint Forfas, Enterprise Ireland and IDA Ireland	Corr na Gaoithe
KiWi Power	CP Energy
Major Energy Users Council	Cronalaght Windfarm
Moyle Interconnector	Cronelea Windfarm Ltd
Power NI	Cronolea Windfarm
Power NI Energy Ltd - PPB	Cwind Ltd
Powerhouse	Dunmore Wind Power Ltd
PrePay Power	Energy Care
RES UK & Ireland Limited	First Electric
Scan Energy	Foyle
Siga Hydro Ltd	Galeforce Energy Ltd
SSE	Greenoge Windfarm Limited
Tynagh Energy Ltd	IRENE Ltd
Vayu Limited	Irish Wind Farmers' Cooperative
	Kilmeedy Windfarm Ltd
	Kilrush Energy Ltd (Enercon)
	Kilvinane Windfarm Ltd
	Knocknagashel Wind Farm Ltd (Enercon)
	Lahanaght Hill Windfarm

Lisdowney Wind Farm
Meitheal na Gaoithe
Moneenatieve Windfarm
Nicandro Ltd
Rathmacan Trading
Sheeragh Wind Ltd
Skehanagh Wind Farm
Sonnagh Old Teo
Templederry WF
The Carlow Kilkenny Energy Agency
Tornado Electric

2 ANNEX: INTERNATIONAL EXPERIENCE OF AGGREGATOR OF LAST RESORT

Aggregation is defined as a specific measure for the aggregation of a set of units i.e. to allow for netting of the volumes from these units when determining imbalance exposure. Examples of this in I-SEM would be Demand and (some) wind

As a transitional measure used in some of the other relevant EU markets, the TSO has taken the role as the aggregator as a last resort solution for especially smaller RES to ease the implementation of Balance Responsibility.

2.1 DENMARK

In Denmark, there were essentially three choices in place for variable renewable generators in terms of discharging Balancing Responsibility requirements:

- Participate on market terms, i.e. be your own Balance Responsible Party (BRP);
- Participate as part of another BRP where a third party takes the role as aggregator on commercial terms;
- Participate through the TSO-organised BRP-club, where the TSO acts as the aggregator, which is no longer open for new members.

In Denmark, where portfolio bidding is generally allowed, some of the bigger market participants with renewable resources already had a big portfolio. Therefore, they started from day one to have the variable renewable resource as part of their overall portfolio.

It didn't take long time before there were service providers (aggregators) that also offered this service to smaller renewable parties on commercial terms. This is also the same experience from other comparable markets with high penetration of variable renewable generation (Germany and Spain) where a high percentage of the renewable generation is managed by service providers.

However, as it took some time to let the market for commercial aggregation to grow, the TSO in Denmark created an "aggregator of last resort" for the RES that didn't want to take the BRP-role themselves but wasn't part of a bigger portfolio and not agreed commercial terms with an existing aggregator to be their BRP. The main purpose was to assist and reduce risk for the RES participants when the RES became subject to Balance Responsibility.

This "aggregator of last resort" was set up to be a temporary measure with an incentive to move away from this.

The main function of Energinet.dk's (the Danish TSO) special "BRP-P club" was to¹⁰:

- sell the output on Nord Pool Spot (DAM, IDM) on behalf of the wind-turbine owner;

¹⁰ The detailed Danish regulation is found at <http://www.energinet.dk/EN/EI/Forskrifter/Markedsforskrifter/Sider/default.aspx>

- undertake the balancing service relating to the wind turbines in question on behalf of the wind-turbine owner;
- settle the proceeds, the feed-in tariff and the wind-turbine owner's share of the TSO's costs relating to this service with the wind-turbine owner via the grid companies (the cost allocation is defined in the regulation).

As the BRP-P club operated in a “passive” mode, an active portfolio management will in the longer term deliver better results. Therefore the variable renewables owners should implicitly be incentivised to either become a BRP themselves or become part of a bigger portfolio (through an aggregator) at a lower cost.

2.2 GREAT BRITAIN

Another solution that is currently being revised is the “Off-taker of last resort” being implemented in the BETTA market in GB. These arrangements are targeted to smaller new renewable entrants to the market to ensure a route to the market.

The Off-taker of Last Resort will provide eligible renewable electricity generators with a guaranteed ‘backstop’ route-to-market at a specified discount to the market price¹¹. This will help investors and lenders understand the ‘worst case’ price that the generator will receive for its power, giving them more certainty over the route-to-market risks and enabling generators to accept more innovative routes to market.

It is intended that this will also allow generators to compete on a level playing field, and bring more competition and innovation into the generation market generally. The Off-taker of Last Resort also aims to stimulate new supplier entry into the Power Purchase Agreement (PPA) market, as generators will not be constrained by lenders relying on large suppliers with strong credit ratings.

In the BETTA market, the Offtaker of Last Resort Discount is set relatively large - 25% so whilst it gives certainty, it will also be possible to get better prices in the market by trading in the market directly or contracting commercially with a third party.

¹¹ <https://www.gov.uk/government/consultations/implementing-the-offtaker-of-last-resort>

3 ANNEX: OPERATION OF DEMAND SIDE AND SPECIAL UNITS IN EUPHEMIA

EUPHEMIA does not contain any Order types that are specific to any technology. The Order types are general and it is up to the individual market participants to model how they will best offer their units into the DAM, and subsequently into the IDM. The SEM Committee welcomes the work done by market participants in identifying which Order types may suit different types of generation as part of their responses to the Draft Decision Paper.

Even though the I-SEM still is centrally scheduled, the nominations that form the major part of the dispatch will be based on the market participants' schedules from participating in the ex-ante markets. This means that the market participants through their bidding behaviour will need to ensure that the resulting nomination is feasible for their unit(s). This is a big change from today's SEM as the responsibility for bidding in the various markets to get a feasible result is moved to the market participants.

As part of the market participant training sessions that will follow in the implementation phase, various possible solutions for special units could be presented. As part of the planned testing of EUPHEMIA in an I-SEM context, there are defined various scenarios for testing the bidding formats as well as the outcome of using this.

In the DAM, Demand Response (DR) essentially participates and bids using the same potential Order types as any generator to represent their (potential) flexibility. There are examples of different types of DR participating in other European day-ahead markets, whether that involves stopping production or moving to alternative energy sources.

Examples of bidding formats that may be particularly relevant for DR include for instance:

- Simple single hour bids where DR can bid in their flexibility with different price steps for the flexibility at the end of their curve;
- Differentiate their bids between the inflexible and flexible portions of their demand portfolio -bidding as price taker for a portion and then offer the flexible part as a single hour bid with different price steps for the flexibility;
- Offering a potential boiler or additional internal production unit as a "flexible bid" - this is not connected to one specific hour, but let the algorithm pick the most valuable hour(s);
- Combination of linked block bids allowing for both flexibility in prices and duration;
- Combination of exclusive groups that also could allow for offering this for flexible blocks of hours; and
- Any combination of the above.

4 ANNEX: SUMMARY OF DECC'S CAPACITY MARKET POWER MITIGATION MEASURES

This Annex provides a brief summary of the market power measures employed by DECC in their newly established quantity-based Capacity Remuneration Mechanism (CRM).

General Considerations

First, DECC has instituted a general prohibition on market manipulation as part of the CRM design. DECC has reminded all participants of their requirements and obligations under REMIT and that, although they relate to energy trading, there are overlaps with the capacity market. As part of this companies must consider Chinese walls and ring-fencing as part of the prequalification process.

Second, DECC are also consulting on legislating to create new criminal sanctions around insider dealing and market manipulation in the wholesale energy markets.¹²

Third, the energy markets in Britain are subject to general competition law and the Competition and Markets Authority, as the body responsible for enforcing competition, has powers to investigate anti-competitive practices and to take appropriate action if it finds against market participants.

Fourth, unforeseen issues may arise once an auction starts and DECC has put in place checkpoints (and contingency plans) which would call for cancellation or suspension of the auction e.g. if so few bidders pre-qualify that the auction will not be competitive or if there were irregularities that compromised a fair and competitive auction.

Use of a sloping demand curve

It is commonly accepted that, even assuming a constant value of lost load (VoLL), the loss of load expectation (LOLE) increases rapidly when capacity is tight; and that in those circumstances energy prices should rise sharply to scarcity levels, reflecting the true expectation of lost load and associated costs. In other words, the demand curve for capacity is very price inelastic once the reserve margin approaches zero and is close to vertical around the target level of installed capacity.

This poses a problem in capacity auctions because the incentive to withhold capacity at that point is strong. The solution to this, not only in GB but also in the US capacity markets, has been two-fold:

1. the construction of a demand curve for inclusion in the auction;

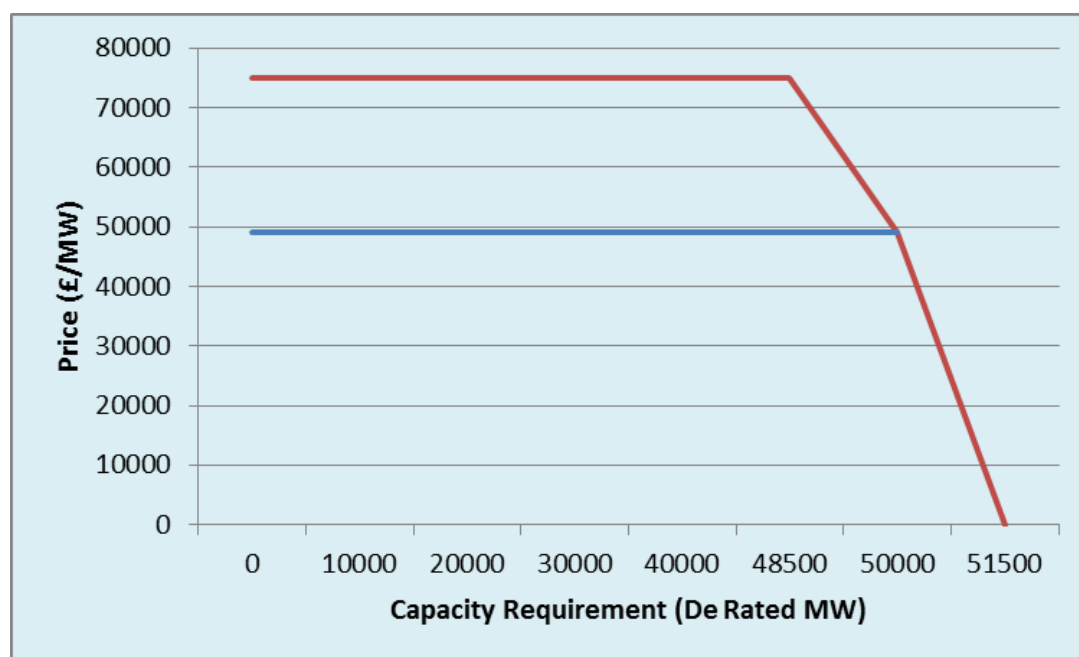
¹² See DECC: *Strengthening the regulation of wholesale energy markets through new criminal offences*. August 2014

- adopting a multi-year forward planning horizon, which creates additional elasticity in the capacity supply curve, since existing capacity is competing on an equal footing in the auction against new capacity coming on stream in four years' time.¹³

One key component of the demand curve is the Cost of New of Entry (CONE) calculation. The CONE is a very similar concept to the Best New Entrant (BNE) used in the current capacity mechanism in the current SEM. The Net CONE (i.e., net of infra-marginal rent and revenues from the sale of ancillary services) for the auction later in 2014 has been set at £49/kW/year (circa €60/kW/year) and is based on an Open Cycle Gas Turbine (OCGT). The current net BNE price in SEM is €81.6/kW/year and is also based on an OCGT fired on distillate.

DECC has instituted a price cap within the curve; this price cap has been set at £75/kW/year.

The slope of the demand curve is set based on the net CONE and a spread of 1,500MW each side of the target volume, which is an improvement on a vertical curve. This is illustrated in



High Level Participation Requirements

Although DECC has stopped short of explicitly making participation in the auctions mandatory, the suite of requirements in place makes the scheme close to mandatory.

¹³ This is because the supply of new capacity is likely to be very elastic, since most competitive new plants will be CCGTs and their supply is relatively unrestricted (by comparison with the capacity of existing plant which is effectively fixed).

Every licensee must come forward and prequalify for the scheme without exception. Participants can make a declaration of non-participation in the auction but it must relate to one of the following issues:

- They plan on closing down their plant before the commitment period
- They do not believe that the CRM would be in their interests, given what is being offered by DECC
- Their plant will be temporarily unavailable (e.g., mothballed) for a period of time which makes participation impossible

A blanket market ban can be imposed on a licensee who proposes closure, either temporary or permanent, and subsequently participates in the wholesale energy market.

Restrictions on Offerings

In addition to high level participation requirements, DECC has imposed limitations on the offerings of participants.

Volume Offerings

Firstly, DECC has placed limitations on the offerings of individual units.¹⁴ This is achieved by de-rating the capacity of each unit pursuant to a DECC/ National Grid methodology. There is a predefined set of methodologies which sets a de-rating factor for each type of plant (i.e., by technology). The use of a benchmark means that at an individual plant level the factor may not be perfect, but overall the methodologies are fit for purpose. Participants know the de-rating factors in advance of the auction and can take account of their own specific plant attributes in their offer prices.

Participants have to offer their de-rated capacity. They cannot offer less than that. This takes away the incentive on a participant to set the auction clearing price by withholding some of its de-rated capacity.

Price Offerings

In addition to capacity offerings restrictions, DECC will place restrictions on the prices bid by auction participants. As a general rule, all existing generating units will be price takers above a certain threshold, while new resources will be eligible to be price makers. In the forthcoming auction the threshold has been set at 50% of net CONE, so existing generating units are constrained to bid no more than £25/kW/year.

However, existing generators can ask to have their price-taker restriction removed by seeking declaration to be a price maker. This is achieved by the submission of a

¹⁴ Bidding will be on a Capacity Market Unit (CMU) basis, which is essentially at the generating unit level.

memorandum under seal to Ofgem (under their competition powers). The memorandum is an important document and must be delivered to Ofgem at prequalification stage. Ofgem does not open the envelope. The memorandum must make clear why they need to be released from the price taker status and at what price level they will withdraw their unit(s) from the auction because the unit needs a capacity agreement to remain operational – essentially a declaration in advance of their net going forward costs. This is to prevent existing generating units to use the latitude of their status as price makers to deviate from bidding their net-going forward costs to artificially raise prices in the auction. Ofgem may use the memorandum as part of any subsequent proceedings against a licensee where they may have gained an unfair advantage from being a price maker in the auctions.

In addition, price takers in the auction can opt out once the price in the auction descends to the price taker threshold. This effectively reduces the risk of capacity prices clearing at zero and is thought will avoid the boom and bust cycles seen in the early versions of capacity markets in the US.

Auction Details

The auction will be a descending clock design with the employment of combinatorial logic. The combinatorial logic will be used at the end of the auction to compute which combination of final round outcomes give the best result overall from a consumer surplus point of view.

- There will be a target capacity of 50,800MW
- The maximum capacity procured at the Price Cap will be 49,300MW
- The minimum capacity procured at £0/MW will be 52,300MW
- The auction will commence at the Price Cap.
- The price decrements between auction rounds will be £5,000/MW
- There will be four days of auctions, with four rounds per day. Each auction window will be 90 minutes with 30 minutes between auction rounds.
- For market power reasons there will be a withholding of information released to participants between rounds.

The detailed Auction Rules are available [here](#).

Further information on the GB Capacity Payment and in particular the auction design and market power can be found in “[Capacity Market Gaming and Consistency Assessment Final Report](#)”, a report by Charles River Associates procured by DECC.