(SEM-14-008)
INTEGRATED SINGLE ELECTRICITY MARKET (I-SEM)

SSE RESPONSE TO CONSULTATION PAPER ON HIGH LEVEL DESIGN FOR IRELAND AND NORTHERN IRELAND

APRIL 2014

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INTRODUCTION AND SUMMARY

About SSE

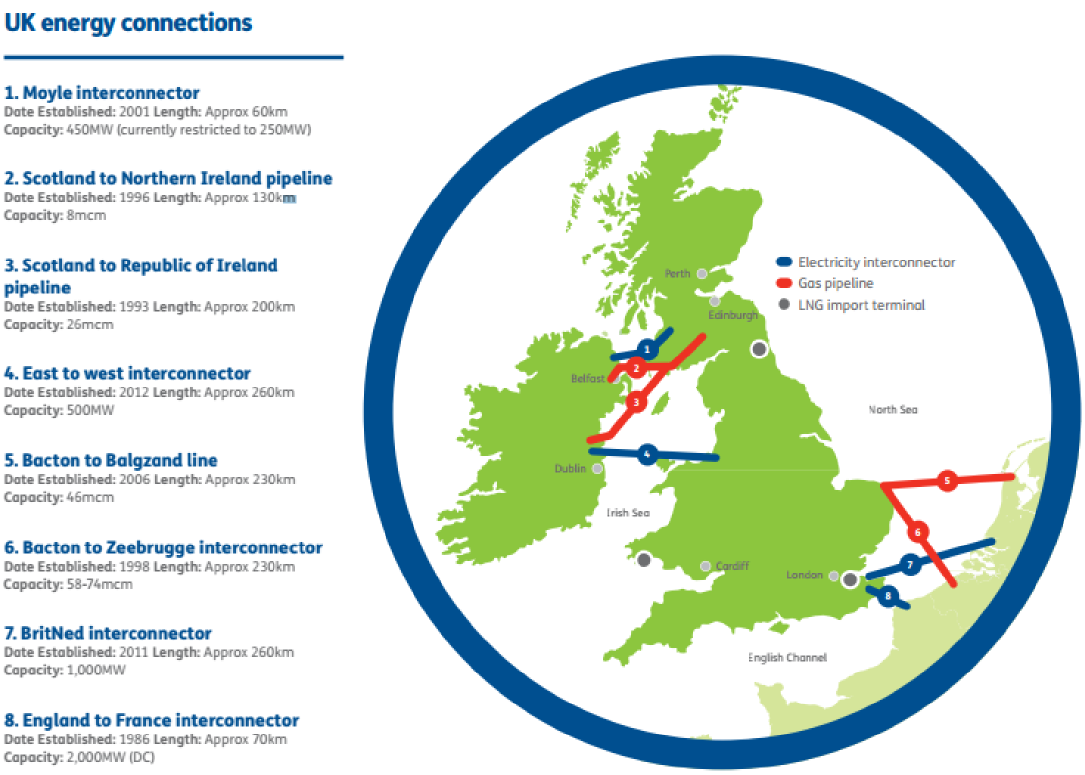
Thank you for giving SSE the opportunity to comment on the SEM Committee's consultation paper on Integrated Single Electricity Market Arrangements for 2016. This consultation paper represents an important step in the design of enduring trading arrangements.

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

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

Pan-European Context

Compared to the SEM, the GB electricity market is much closer to full compliance with the European Target Model, because its initial structure more closely reflects a typical European electricity market. The physical energy infrastructure linking the two markets, GB and Ireland is shown below.



At points, we have referenced the impact of Target Model implementation on price formation and interconnector flows in GB. Because pan-European DA auctions only commenced in early February 2014, there has been no impact on the physical characteristics or market structure of the GB system.

Even in Nord Pool, where market coupling has been in place for many years, the impact of more efficient interconnector flows has not had a significant impact on physical system characteristics or market structure. A market designed with the exclusive goal of efficient interconnector flows will not deliver the best short or long run outcome for customers on the island of Ireland.

Our key concerns

When do design decisions need to be taken?

We hope that comments made by industry participants are fully considered, particularly on the fundamental High Level Design aspects that haven't been fully described in the High Level Design paper. **There are certain design decisions that will need to be made by the publication of the final design in August, and certain design decisions that can be properly considered and finalised during implementation.** Taking decisions on aspects of design that haven't been adequately described in the decision paper will lead to issues and delays during implementation.

Can an energy only market deliver for Ireland?

Energy-only markets across Europe have not performed well against changes in the underlying physical generation mix and regulatory/political intervention over the last decade. These changes have led to:

- **Short run distortion –** ranging from loop flows to sustained periods of imbalance and negative pricing.
- **Long run distortion –** ranging from the undesirable stranding of modern, efficient assets to substantial capacity shortfalls at a member state level.

There has been a flight away from energy-only markets, with Eurelectric acknowledging that:

"[I]n view of growing generation adequacy concerns due to increasing RES penetration and, in some cases, peak demand, a review of the current market design is becoming increasingly needed in some regions across Europe. [.....]CRM should be considered as an element of a new market design."

SSE believes that a split of capacity and energy is desirable in any new HLD, even if there is no explicit enforcement of the separation between the two through a BCoP.

However, given that the explicit energy and capacity split under the existing SEM is familiar and proven, we believe that this design under Option 4 should be considered the benchmark against which other designs can be compared. This explicit split has resolved indivisibility, price indifference and market power issues.

Does European liquidity resolve market power?

Moving from the Single Priced SEM arrangements necessarily fragments participation across a number of different timeframes. The options taken forward may each have distinct forward, day-ahead, intraday, balancing and imbalance periods and prices. There is a risk that fragmentation will lead to 'thinly' traded markets[1].

This is a negligible risk in synchronous continental European 'Target Model' markets, but a very real risk in Ireland. Ireland is a small synchronous system with high variable uncertainty, market dominance issues and limited DC interconnection to other bidding zones. Thinly traded markets will expose consumers and participants to the exercise of market power.

There are solutions:

- **Explicit energy/capacity split** - preserving the current SEM market design through the SRMC ex-post pool and LRMC capacity arrangements under Option 4.

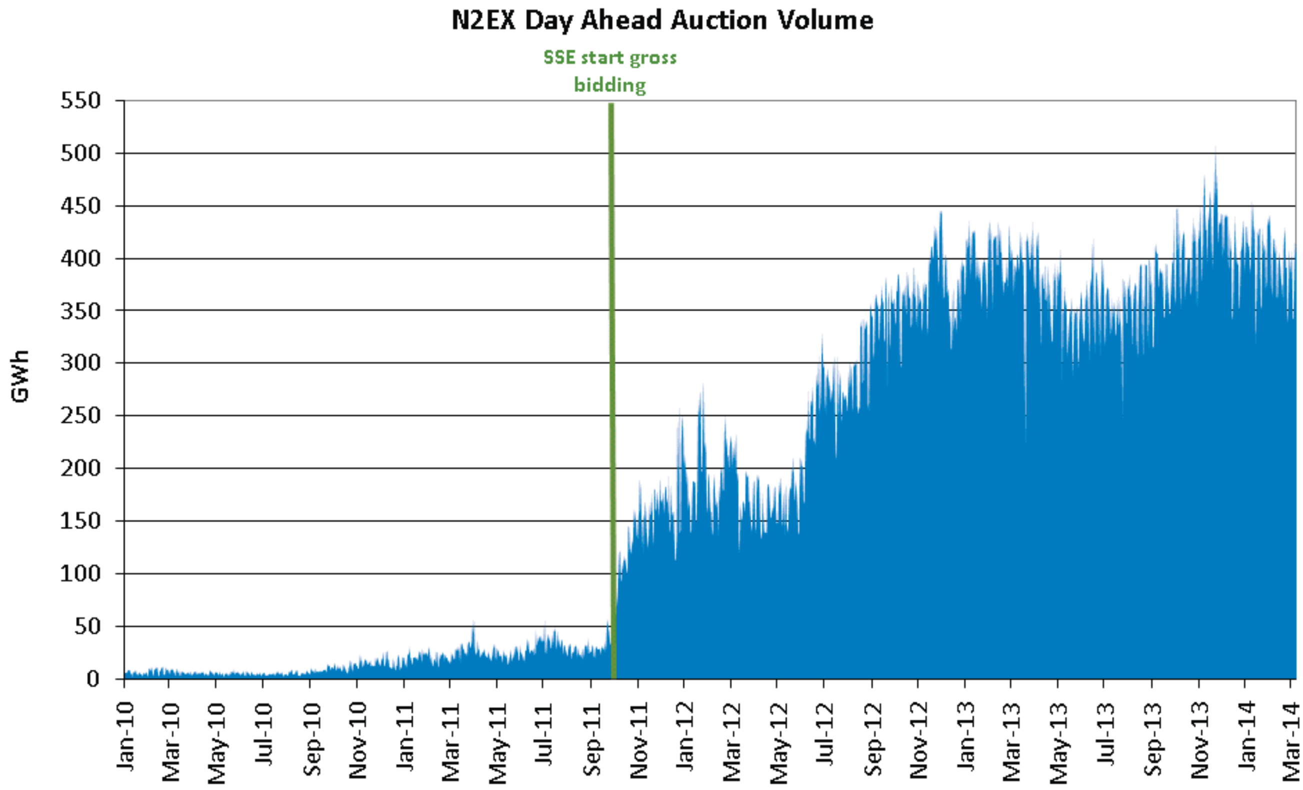
- **Freeing up capacity –** removing the opportunity for market participants to strike firm physical bilateral contracts in the Forward period.

- **Exclusive marketplaces –** applying the concept of 'exclusivity' to the DA and ID markets. Participants cannot adjust their positions outside of registered market places.

- **Mandating Participation –** a step beyond exclusivity would be mandating participation in the DA timeframe. SSE believes that mandatory participation may deliver benefits on Ireland's system.

SSE voluntarily introduced a similar approach to GB trading in October 2011. We began to phase in the auctioning of all of our supply and demand through the N2EX day-ahead platform. Mandation is possible. We now regularly commit 100% of our volumes at the day-ahead stage – the effect on volumes in the market can be seen in the next figure:

[1] This is a particular risk in the 'Irish' parts of any market – Forwards and Balancing.



SSE's response

Considering the level of detail provided on the 'Ireland-specific' features of market design within the consultation paper, we have not been able to recommend an 'off-the-shelf' **Option** in our response. We have instead looked at design features that would suit the physical and market structure characteristics of Ireland.

Our response looks at the assessment criteria as defined by the SEM Committee, and then outlines the preferred design features of a capacity and energy solution. The questions within the consultation paper are answered implicitly by the main paper and explicitly in **Annex I**.

If further information or clarification is required on any aspect of this response, SSE will be delighted to provide the RAs with the required information.

THE RAS' ASSESSMENT CRITERIA

Criteria vs design features

The "Next Steps Decision Paper[2]" sets out criteria for assessing each of the energy trading arrangements. It also includes some decisions on design features, most notably:

> *"[T]hat the SEM high level design [....] 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."*

The SEM Committee has moved from this position, but the reasons for that change should be made clear. It is unclear from the consultation paper how this assessment will take account of any CRM. We have provided comments on each of these

Internal Energy Market (IEM)

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

The existing SEM cannot effectively deliver **Day Ahead Market Coupling** and **Intraday Continuous Trading**, although it could provide for **Cross Border Forward Hedging and Harmonisation of Capacity Allocation Rules, Capacity Calculation and Zones Delimitation** and **Cross Border Balancing.**

Implementation of the IEM centres on compliance with these five pillars of the EU Target Model. Assuming that specific details under each option are better defined, SSE is confident that each of the Options could be considered compliant.

Moving the SEM from a position of cross border arbitrage to genuine market coupling is a separate question. Whether each option would ensure efficient cross border trade is less clear. This is explored in more detail in the **efficiency** section

Competition

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

Looking at a simple view of installed capacity or market volume in the SEM does not give an accurate picture of market structure. It also ignores market structure on the demand side. We do not think that the Eurostat data showing market share of the largest generator in Figure 5[3] is particularly useful. If you used similar data to assess competition in the UK wholesale market, you would miss many of the issues that have led to the introduction by Ofgem of a ***'Secure and Promote'*** licence condition.

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[2] SEM-13-009 Next Steps Decision Paper (2013), SEM Committee
[3] Page 17, SEM-14-008 Integrated Single Electricity Market (I-SEM) High Level Design for Ireland and Northern Ireland from 2016 (2014), SEM Committee

In SEM, some of those issues were explored through the SEM Market Power and Liquidity project in 2012. The final decision paper came to a number of conclusions:

Spot Market Power

> *"In view of the effectiveness of the BCoP, MMU and DCs to date in the SEM, and given current and predicted SEM spot market power levels, the SEM Committee will maintain a robust market power mitigation strategy through these instruments for the foreseeable future."*

Given that the BCoP and MMU would become irrelevant under some of these energy market designs, compensatory measures would need to be outlined. Increased integration with Europe is compensation, although it is dependent on the size, performance and availability of interconnection capacity[4].

ESB Vertical Integration

> *"[T]he SEM Committee continues to be of the view that vertical integration of ESB would be damaging to the market and will not allow it at this time. The SEM Committee will not give a timescale for the removal of ring-fencing because it would depend on the circumstances, which would need to be considered at the time."*

SSE has looked at the extent to which integration would erode ESB's market share in SEM under the energy trading options outlined. Even if all physical volumes exclusively flow through European markets (DA and ID), consumers and market participants will be exposed to the exercise of market power in the Forward and Balancing Periods particularly in situations where vertical integration was approved.

Contract Liquidity

> *"The RAs continue to believe that contract liquidity should develop organically for now and welcomes the new Tullet Prebon "Over the Counter (OTC)" facility in this regard. As part of this organic development, the RAs would be keen to see this develop further, with industry participation among both sellers and buyers."*

The Tullet Prebon OTC facility has been in operation for a number of years now, and substantial liquidity has not developed organically. While a liquid DA market should develop if physical forward trading is prohibited, suppliers in particular are dependent on liquidity along the curve for risk management.

Forward hedging will continue to be a major concern for suppliers (particularly smaller suppliers) under any of the energy market designs. Given that the current market structure[5], **SSE believes that the competition criteria should be assessed against whether a design delivers effective market power mitigation.**

[4] The reliability of HVDC Moyle over the last number of years illustrates the vulnerability of a market power mitigation approach based on available interconnection.
[5] More information on **Market Structure and Market Power** is available in **Annex I**

Security of Supply

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

There are two aspects to wholesale market design that will whether or not the system can be operated within relevant security standards:

I. Does the TSO have sufficient information on, and control over plant on the system?

II. Will the TSO have sufficient plant on the system to meet expected demand?

So, does the TSO have sufficient information on, and control over plant on the system under each of the options?

The energy options outlined give sufficient detail on the first. The TSO will know the point at which they will (or won't) receive unit nominations from participants, the period during which they may receive renominations and the array of potential energy and non energy balancing actions available to them throughout the trading day.

Will the TSO have sufficient plant on the system to meet expected demand?

Currently, the SEM's design means that the TSO will have plant available. Moving to each of these new structures as defined, the TSO cannot accurately assess whether they will have sufficient plant on the system to meet expected demand under each option[6]. The answer to this question is provided by the market – the aggregate of market participant decisions on investment and closure combined with physical constraints on operation and transmission.

Can this criterion be assessed without a defined CRM?

Revenue adequacy for plant or investment projects in the existing SEM is relatively easy to model. The Bidding Code of Practice (BCoP) defines cost items that can be included in a generator's Commercial Offer Data. Income from the Capacity Mechanism to cover fixed costs is relatively stable, assuming that a generator has high availability.

In an energy-only market, or an energy market with an undefined capacity mechanism the process is more iterative, with chains of decisions precipitating further chains of decisions. SSE has detailed GB's experience with known generation closures due to hard constraints (Large Combustion Plant Directive (LCPD), IED etc) and capacity closures due to market conditions (deteriorating spark spreads and political/regulatory uncertainty) in **Annex III.**

SSE believes that this criterion cannot be accurately assessed by the TSO alone, and cannot be assessed without a defined CRM. **An energy-only market cannot deliver security of supply as the 'missing money' effect means the market cannot deliver the appropriate level of investment.**

[6] More information on **TSO Forecasts and Revenue Adequacy** is available in **Annex II**

Efficiency

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

Economic dispatch or technical dispatch under the Bidding Code of Practice

Under the existing SEM, an ex-post unconstrained schedule is produced for the entirety of the market (subject to de-minimis limits). The TSO then schedules and dispatches the system to minimise the overall cost of production based on bids into the pool. Those bids follow the structure within the Trading and Settlement Code (TSC) and BCoP.

The BCoP is rigid, particularly on the point of valuing relevant cost-items:

> *"(i) [W]here there exists a recognised and generally accessible trading market in the relevant cost-item, the Opportunity Cost of that item should reflect the prevailing price of the cost-item, which may be for immediate or future delivery or use as appropriate to the circumstances of the relevant generator, having regard to:*
>
> *(a) [C]osts the relevant generator would incur in offering that cost-item for sale, or acquiring that cost-item,* ***on a recognised and generally accessible trading market;***
>
> *(b) [R]easonable provision for the variability of the prevailing price of a cost-item on a* ***recognised and generally accessible trading market;****"*

This effectively separates commercial purchasing from contractual purchasing. Where a recognised and generally accessible trading market exists, a generator must use that price. The incentive shifts from attempting to beat competitors, to attempting to beat the reference price (although this is irrelevant to efficiency).

The resulting dispatch is the most efficient technical dispatch at the point at which bids are submitted. However, without a BCoP in place, generators would change their behaviour. The resulting dispatch may be a more (or less) efficient economic dispatch, but it is unlikely to be a more efficient technical dispatch for the island of Ireland.

However, interconnector flows are fundamentally economic, rather than technical. Deciding on efficiency becomes a choice between the extent to which efficient interconnector flows can be assumed under any option and the impact of those interconnector flows on technical dispatch.

Importance of starts and part-loading in the SEM

The consultation paper notes that:

> *"The small market size and the relatively large within-day swing in demand in the SEM combined with increased levels of intermittent wind on the system*

increase the relative importance in the SEM of the start-up, shut-down and part-loading of generation plants."

SSE would agree with that statement. However, optimising the start-up and part-loading of plant is dependent on the balancing mechanism and imbalance arrangements. Because the consultation does not provide any detail on imbalance calculation, it is difficult to assess how market participants and the TSO might behave during the day[7].

The paper outlines an area that should be central to the assessment of the efficiency criteria, without defining the design aspects that are most likely to influence efficiency of dispatch under each of the Options.

In the qualitative assessment of each of the options, each receives a neutral score in relation to the efficiency criteria, despite the fact that there are very clear differences between an integrated scheduling process and a balancing market. Efficiency through balancing and imbalance price calculation is briefly explored in our section on energy market design.

Equity

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

The equity criterion is not clearly defined – the initial qualitative assessment under each of the options focuses on two aspects of design that appear to have a natural tension.

- **Equality of access to different markets:** If a market is structurally attractive[8] then trading should take place there, guaranteeing some level of liquidity. The only barriers to access will depend on external decisions around areas like collateral requirements, volatility, complexity, connection policy etc.

- **Cost reflective prices:** Ensuring that prices are cost reflective i.e. that they properly reveal the actual value of 'flexibility' or energy on the system in real-time will necessarily increase volatility, complexity and ultimately risk to participants. This will make participation in markets more difficult for smaller generators and suppliers.

If assessment is limited to these two characteristics, ensuring the equity criterion is met primarily appears to be about making the registered market places **exclusive** rather than **non-exclusive**. If the RAs ensure that physical capacity cannot be

[7] For example, under certain designs, participants may prefer to have their own part-loaded plant on the system as a cushion against a thinly traded balancing mechanism with volatile imbalance prices

[8] For example, the Day-Ahead market is **structurally attractive** as a result of its timing and uniform auction characteristics, which provide a robust reference price for the settlement of any financial contracts. The risk of those financial contracts will be managed by trading in the Day Ahead market. **If physical capacity cannot be withheld from registered market places, that market should be liquid.**

withheld from registered market places through Irish bilateral physical forward trades the DA market should be liquid and accessible.

However, ensuring that prices are fully cost-reflective (i.e. volatile and complex) across all pricing periods (particularly those in which participants are exposed to local market power – balancing and imbalance) will impact on the extent to which smaller participants are comfortable to participate in the market, or whether they feel more comfortable having that risk managed by a larger company.

Exclusivity provides most of the solution in ensuring equality of access for participants. If exclusive, the DA market will be structurally attractive, liquid and deep.

Cost-reflectivity (because of dependence on the effectiveness of local arrangements and the extent to which they are protected from the exercise of market power) must be balanced against impacts on participation and the **competition, security of supply, efficiency, practicality** and **environmental** assessment criteria.

Stability

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

We believe that assessing this criterion is effectively asking whether participants would expect a requirement for regulatory interventions under each of the different options. However, the paper also notes that:

> *"The assessment of this HLD criterion focuses the extent to which a final HLD will be in line with historical expectations, and how robust (as much as possible) it may be to any future changes (.e. g. in national or European policy, or in the physical or structural aspects of the market)."*

We would suggest that both 'historical expectations' are only relevant to the extent that the design characteristics of the existing SEM could be maintained under each of the options. This could cover what happens to:

1 Market Power Mitigation
2 Gross Participation
3 Central Commitment
4 Complex Bidding
5 Single Pricing
6 Firm and Non-Firm Physical Transmission Access[9]
7 Explicit CRM

Some can potentially be preserved, whereas others may require substantial change. As long as these changes are properly justified – i.e. a clear justification is given for movement away from design features that have been acknowledged as providing benefit by the RAs and market participants then *historical expectation* becomes a less important consideration.

[9] We expect that this will require substantial change under all of the Options, except for Option 4.

With regard to a market's resilience to *'future changes'*, SSE would suggest that this is better covered by the **Adaptive** criterion.

Returning to the first question, *"Do participants expect regulatory interventions under each of the options provided"* we find that this is relatively straightforward to answer for the energy arrangements, but more difficult to answer for the capacity arrangements from the information provided in the paper.

Capacity Arrangements

Without any detail on whether a CRM would exist, or how a CRM option could work, SSE cannot comment on our expectations of regulatory intervention. However, we can say that any CRM should include:

- A **clear and transparent rule set or methodology** that market participants and 'rational investors' can understand.

- A **central, clearly defined set of objectives** against which any changes to that methodology or rule set can be assessed.

Those should help to secure stability and protect the out-turn results of the methodology from repeated intervention. **Stability is particularly important with regard to capacity arrangements, as it takes a number of years to build credibility and familiarity with investors and just a single opportunistic intervention to reset that process.**

Energy Arrangements

Stability under energy arrangements is easier to assess from the detail provided in the consultation paper. **If an option provides opportunities for participants to withhold capacity from registered marketplaces, then regulatory intervention is more likely to be required in order to ensure liquidity and transparency.**

Similarly, if an option is primarily dependent on shared order book functions for the settlement of physical energy trades, it is less likely that changes could be made that would affect the majority of cleared volumes. **However, dependence on either the DA or ID shared order book functions will vary with regulatory intervention.** Incentives or penalties on certain types of behaviour will inevitably change a market participants' exposure to European or local arrangements.

Adaptive

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

The paper notes that:

> *"The governance arrangements for any set of trading arrangements tend to be determined at the implementation stage, i.e. a level of detail below the*

HLD. Therefore, adaptability is typically not a major distinguishing feature of different energy trading arrangements."

We would agree with that observation, although we would add that the existing SEM's Governance arrangements have contributed to the markets success. The Trading and Settlement Code (TSC) and the Modifications Committee have provided a level of transparency, process and rigour to market development. **These characteristics should be retained under the detailed governance arrangements in any new market design.**

Practicality

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

Participant costs

The cost of participant systems to participate in the European DAM and IDM should be low. Operationally, the requirement for continuous intraday trading under the Capacity Allocation and Congestion Management Code (CACM) will require 24 hour trading functionality, delivered by a participant or intermediary, which will increase the cost of 'full' participation.

Under the local arrangements, the cost of systems and participation will depend on whether a balancing or pool mechanism is chosen. The paper describes the two different sets of commercial information that participants will have to provide:

> *"Complex bids for use in an Integrated Scheduling Process designed to produce unit commitment."*

Complex bids are inherently simple to produce, submit and update, assuming that there are rules around submission and update of bids, and a defined point at which the optimisation problem is resolved[10]. The cost of participation should be low.

> *"Simple incremental and decremental bids (INCs and DECs) for use in a separate Balancing Mechanism that produces an economic merit order."*

The submission of simple incremental and decremental bids into a balancing market will require more investment in terms of participant systems to interface with the central system. Operationally, the 'iterative' nature of balancing bids and offers will mean that full participation would require 24 hour trading functionality, increasing operational costs.

[10] In the two options **(Option 2 and Option 4)** in which an Integrated Scheduling Process is required, we assume that optimisation is carried out at defined point, with an economic dispatch tool used for actions closer to real time based on the complex commercial and technical data previously submitted.

Central costs

As with our comments on participant systems, the cost of central systems to interface with the European DAM and IDM should be relatively low, because we would expect that there will be a variety of standardised solutions available by the implementation stage.

Under the local arrangements, the cost of the central systems required will depend on whether a balancing or pool mechanism is chosen:

> *"Integrated Scheduling Process means a continual process that uses at least Integrated Scheduling Process bids which contain commercial data, technical data of each Power Generating Facilities or Demand Facilities required for this process, the latest Responsibility Area Adequacy analysis, and the Operational Security Limits as an input to the process; which then simultaneously optimises reserve procurement, congestion management and Balancing Energy procurement over a set time horizon in order to produce an indicative Active Power output schedule for the dispatchable resources in order to ensure Operational Security.."*[11]

Solving this optimisation problem will require the TSO and MO to procure an expensive, bespoke tool, except for under **Option 4**, which should be able to use the existing SEM optimisation engine with some minor variations. The alternative is a separate Balancing Market:

> *"Balancing Market means the entirety of institutional, commercial and operational arrangements that establish market-based management of the function of Balancing within the framework of the European Network Codes."*

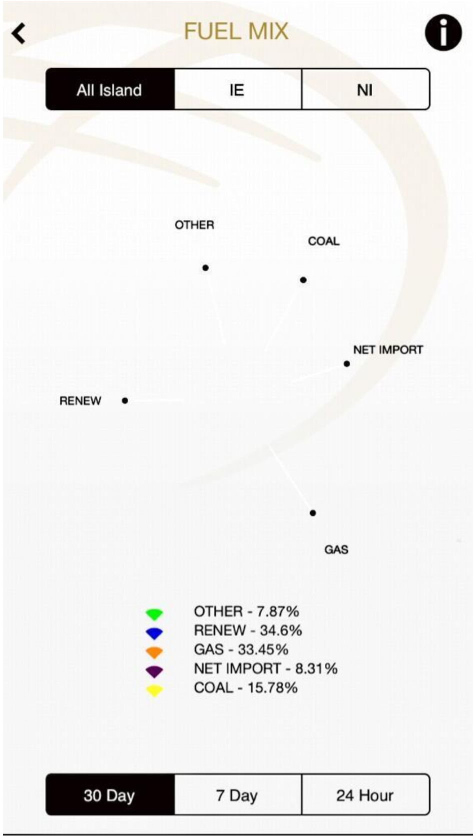
Developing a Balancing Market will not be a simple task. SSE would note that the out-turn cost for the implementation of two additional gate closures to facilitate intraday trading was approximately €17 million. The Imbalance Pricing guide[12] that explains cash out arrangements in Great Britain runs to 52 pages. The Balancing and Settlement Code itself is many times longer. **We would suggest that the costs of implementing a *'simple balancing mechanism'* relative to a pool based optimisation tool are not to be underestimated.**

Environmental

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

The contribution of variable generation to Ireland's overall generation mix is far more pronounced than in any other European synchronous energy system. The figure below shows All-Island Fuel Mix over a 30 day period in winter – renewables (predominantly onshore wind) are making up 34.5% of production over a period of peak demand.

[11] ENTSO-E Network Code on Electricity Balancing (2013), ENTSO-E
[12] Imbalance Pricing Guidance, a guide to electricity imbalance pricing in Great Britain (2013), Elexon



While the SEM Committee is correct in noting that a market cannot be designed specifically around renewable generation, certain design features could make trading, scheduling and risk management particularly difficult for renewable generators.

In a traditional power system, there are three main sources of uncertainty:

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

Of these, **variable uncertainty** will be the largest source of forecasting error at the DA market stage in Ireland. Forecasting will improve the closer to real-time trading can take place, but this is manageable. **SSE currently sells 100% of its supply and demand portfolio[13] at the DA stage in GB with no issues.**

If managing variable uncertainty is a major concern, a solution is to concentrate physical trading within an ex-post pool as with the current SEM arrangements and as under **Option 4**. This effectively spreads the risk of variable uncertainty across the entire market and socialises energy balancing costs across all market participants. Incentives to increase predictability closer to real-time will still exist, as without

[13] Our GB supply portfolio includes a substantial proportion of variable generation, including both wind and run of river hydro.

participation in ex-ante within-day trading there will be an increased risk of curtailment, hence financial trades will be made to shift interconnector flows.

CAPACITY

What are the characteristics of Ireland's Power System?

The consultation paper includes a description of the all island market:

> *"The all island market is a small synchronous system, with no AC interconnection to any other market. This has historically meant that there has been particular concern about the sensitivity of the capacity margin to plant entry and exit, which has supported the use of an explicit CRM in the design of the SEM."*

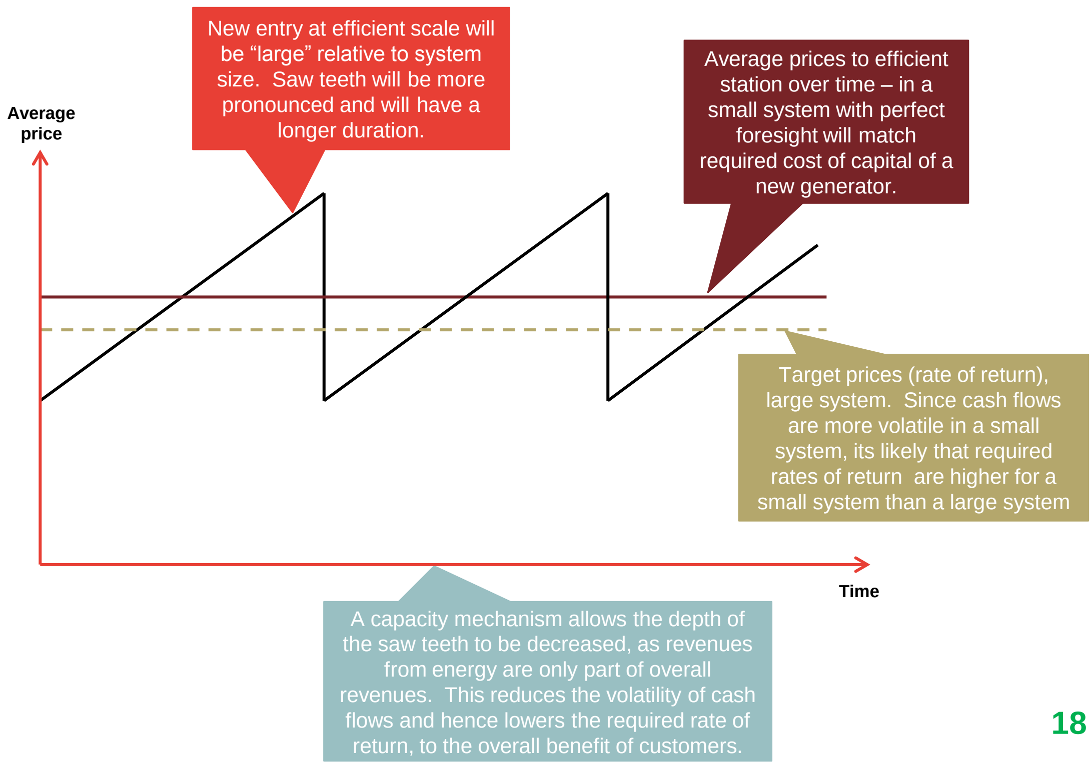
It also notes that one of the fundamental changes since the creation of the SEM has been:

> *"A changing generation mix, with much greater penetration of wind today, and targets for renewable electricity penetration of around 40% by 2020."*

These characteristics underpin the all island market's continuing need for an explicit CRM. Maintaining secure supplies means overcoming:

I. **Indivisibility** – the size of a generating unit relative to the size of the all island system will always represent a design challenge. Scarcity rents are not maintained through normal market entry as the overall system moves into a position of structural surplus. Investment risk is substantially increased for new and existing market participants because the scale of that structural surplus is proportionately larger in a small system.

   Without an explicit CRM, indivisibility ultimately translates into unnecessarily high investment costs **and** a tendency to maintain an inadequate de-rated capacity margin. This is noted in Frontier Economics report for the Electricity Association of Ireland (EAI):



The risk reward profile for investments in an energy only market does not provide a signal to build an adequate or economically efficient level of generation. Risks on smaller, weakly connected systems are such that generators are likely to build less capacity than customers would ultimately need. The social nature of electricity reliability[14] will inevitably translate into missing money.

II. **Price Indifference** – the island system has a disproportionately large installed capacity of variable, price indifferent generation (primarily wind generation).. This generation is effectively price indifferent for two reasons:

- **Negligible or zero marginal costs of production** – depending on the design of any accompanying support mechanism, there is no additional cost of providing an additional unit of output. Currently, these units tend to participate in the market as 'Variable Price Taker' units, with their behaviour fixed by the Trading and Settlement Code[15]. While this behaviour may partially change under different energy trading arrangements, generation units with zero marginal cost of production will participate in an energy market in a way that maximises their volume, as long as the price remains above zero.

- **Out of market supports** – there are a number of out of market support schemes available for renewable generation units in Ireland, primarily, the Renewable Energy Feed In Tariff (REFIT) and Renewable Obligation (RO). Remuneration under both of these is based on metered output, which dictates market behaviour. Under the RO scheme, participants may in fact decide to bid negative energy prices up to the value of certificates to avoid losing volume.

If we assume that the structure of these support mechanisms will not change, it is impossible to see how an 'impure' energy price could provide an accurate signal for long run investment for generation in Ireland. A level of revenue adequate back-up capacity will be required to ensure security of supply. If we assume that the structure of renewable support mechanisms will change, a substantial proportion of Ireland's total capacity will still have been built without reference (or with dampened reference) to the prices achievable in the wholesale energy market.

The first characteristic has been acknowledged in the design of the existing SEM which employs an 'integral' CRM in its market design. The second characteristic is

[14] Customers cannot contract for a differentiated level of reliability and would be unwilling to enter into long term contracts, despite the fact that some customers place a different value on security of supply.
[15] The Trading and Settlement Code states that for a Variable Price Taker Generator Unit: *"The Commercial Offer Data shall include only a Nomination Profile (as set out in paragraphs 5.12 to 5.14) and a Decremental Price for each Trading Period. The values of Decremental Price (DECPuh), for each Variable Price Taker Generator Unit u in each Trading Period h, submitted by the Participant shall be equal to zero."*

becoming increasingly important, but is partially compensated for by the design of the energy arrangements in the current SEM.

Without a CRM of any kind, it is certain that conventional plant required for the stable operation of the system will be mothballed up until the point at which remaining generation units can extract sufficient scarcity rent. This will be at the point at which:

- Plant closures or mothballing have led to the withdrawal of substantial volumes of dispatchable capacity creating;
- An inadequate de-rated capacity margin on the all-island system;
- Which in turn allows a dominant generator to set an adequate price for generation (this will be a moving target as the de-rated capacity margin needs to adjust to the continued deployment of price indifferent generation)

The examples below show the likely costs, running and revenues for two generic CCGT units in 2013/14. In an Irish system that has met its 2020 RES-E targets, zero marginal cost plant would have substantially reduced load factors.

- Generic CCGT with 54% efficiency would see a spark of €8.60/MWh in 2013/14. A unit bidding in at this level of efficiency would have an MSQ load factor of 5%, so **450 MW * 5% * 8760 hours * €8.6MWh = €1.695M spark profit**

- Generic CCGT with 56-57% has a spark of €11.50/MWh in 2013/14. A unit bidding in at this level of efficiency would have an MSQ load factor of 23%, so **450 MW * 23 % * 8760hrs* €11.5/MWh = €10.425M spark profit**

Excluding fixed investment costs (which would make up a large proportion of total costs) a generic CCGT would have per annum fixed costs of approx **€15-20m.** Even under current Irish system characteristics with an energy only market all CCGTs with moderate running would be in danger of going off line.

This level of unnecessary economic destruction – technically undesirable plant closure, stranding of assets (and associated impact on company skill sets and balance sheets), rekindling of market power issues etc – does not seem like a desirable outcome of the new market design.

An explicit CRM is needed to rebalance the risk/reward relationship for generation.

Solving the problem with the same solution?

The existing SEM is a capacity and energy market, with generators receiving revenue for making capacity available to the market, and generators receiving revenue for generating electricity. This has effectively solved both **indivisibility** and **price indifference** issues.

It has also been designed to resolve underlying market structure issue by applying an explicit separation between short run energy and long run capacity through the Bidding Code of Practice (BCOP). As acknowledged in the CEPA report on Market

Power and Liquidity[16] the structure has also been successful in separating Short Run and Long Run costs:

> *"Overall, we believe that the BCoP, together with the monitoring by the MMU, has been effective in ensuring that most bids are made at or very close to their SRMC. This means that prices within the SEM are relatively predictable if prevailing levels of fuel costs and demand outturn are understood because the merit order for plants is relatively predictable."*

This has been clear in out-turn SEM wholesale market prices, where SMP tends to track underlying fuel prices (particularly DA NBP gas). The paper also notes that the BCoP is a very effective market power mitigation measure:

> *"[W]ithout any other provisions the BCoP heavily constrains the ability of any market participant to exploit any market power they may have, even if the market power is only transitory. [....] The apparent success of the BCoP and MMU suggests that these provisions are effective and will and should remain in place for the foreseeable future to mitigate the risk of any market power being exploited, with an enhanced MMU."*

Under Option 4 the BCoP and the existing CRM can be preserved in full. Given its success in separating out short and long run costs and in mitigating market power, SSE believes that this unchanged structure should be considered the benchmark against which other options are compared.

However, if structural changes to the energy trading arrangements are considered necessary or desirable (i.e. if any option other than option 4 is considered, a redesign of the capacity arrangements will be required)

How else could the arrangements reward capacity?

Moving away from the integrated scheduling process described under Option 4 means moving to a market in which the settlement of physical volumes will be fragmented across various different timeframes. The BCoP would not be enforceable (or desirable) under these energy trading arrangements, and therefore the structure of a CRM would have to change entirely.

What should a new capacity mechanism be designed to do?

There are two parts to any capacity mechanism:

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

So, any design should achieve a minimum desired supply security level by encouraging new capacity to be built and existing capacity to remain on the system[17].

[16] Market Power and Liquidity in SEM, A report for the CER and the Utility Regulator (2010), Cambridge Economic Policy Associates Ltd

[17] Getting the balance right between new and existing capacity should generally be resolved by the energy arrangements, rather than the capacity arrangements.

It should provide that capacity signals to be available at times when it is required (i.e. when the system margin is low)

Market-wide or targeted?

A targeted capacity approach (i.e. Strategic Reserve (SR)) is effectively an ancillary service. It would not reduce any of the risks that a generator would face in the energy-only market, and would not mitigate the two underlying issues – **indivisibility** and **price indifference.** A targeted mechanism simply provides a route for existing capacity to exit the market, therefore increasing risks for the remaining participants in the market.

A strategic reserve on a small island system may in fact act as an additional barrier to efficient investment:

- If the despatch price of a SR is set at a level close to a theoretical Value Of Lost Load (VOLL) e.g. €10,000/MWh then this would have a limited impact on existing plant on the system. However, investors would expect that the TSO would dispatch the subsidised SR plant into the market before prices reach VOLL.

- Investors would therefore discount the capacity income expected through system scarcity. The SR actually ends up adding to political and market risk, by providing a route for existing generators to move out of an unattractive energy market to a stable SR.

- A strategic reserve is also very difficult for Demand Side Response (DSR), storage or interconnected generation to participate in. A storage or interconnection unit will not choose to limit the use of their asset to one hour per year, as this would negatively impact on their ability to receive revenue from other ancillary services.

We believe that targeted mechanisms are likely to increase risk within the residual energy market, and provide an attractive alternative (for conventional participants) to that energy market. Both of these are undesirable outcomes.

Market wide mechanisms provide generators and investors with a greater degree of transparency and certainty about the value of capacity at a given point in time, while reducing risk within the energy market.

Volume or Price?

As mentioned previously, if structural changes to the energy trading arrangements are considered necessary or desirable then a CRM will need to interact with those arrangements. It is difficult to design a functioning price based mechanism that would provide adequate forward visibility to generators and investors. The consultation paper notes that:

> *"If the ex-ante capacity price is added to bids into the DAM, then this will effectively allow capacity in other countries to access the scheme through the*

> *market coupling process (subject to there being sufficient available cross-zonal capacity). Exports will also pay the same capacity price as domestic demand through its inclusion in the market coupling process."*
>
> *"These total resulting payments to all available capacity in any month may not equal the initial monthly pot as there will be a deviation between forecasted available and resulting available capacity as well as forecasted demand and actual demand. Therefore, a mechanism will need to be put in place to deal with under/over recovery – this cannot be done by having an ex-post element in the price, as this would distort cross-border flows."*

We cannot see a clear mechanism for dealing with under/over recovery that would work with market coupling. Therefore, if the RAs decide to move away from the Integrated Scheduling Approach described under **Option 4**, with the clearly defined BCoP and CRM methodology, then a short-term price-based CRM appears to be favoured in the consultation paper.

This would not provide any real forward visibility to generators or investors, and could be vulnerable to gaming in a market with dominance issues. By ruling out price based mechanisms under **Options 1 to 3**, you are left with various versions of a volume based mechanism.

So, what should the volume based mechanism deliver?

SSE believes that the key deliverables of a capacity mechanism should be defined as the following:

- Create a sustainable, consistent and predictable market for capacity to provide a long-term investment signal for generators.
- Increase the stability of the income stream required to cover investment in existing and new generation. The capacity market should not be expected to de-risk other aspects of investment, such as price competition, technological obsolescence.
- Maintain market signals to govern plant operation, investment, entry and exit, and avoid undue centralised control.
- Offer equal incentive to provide capacity, regardless of plant age or form of generation. All forms of plant, new and existing, should participate in the market based on their ability to provide capacity.
- Maintain a narrow focus on providing resource adequacy, leaving other policies or mechanisms to influence fuel mix, system stability, and plant closures.

We have included a high level volume based mechanism in **Annex IV.**

ENERGY

The consultation paper acknowledges that the SEM has performed well to date against its statutory objectives. It also notes changes to the physical and commercial characteristics of the market since the creation of the SEM, with particular reference to:

- Increased DC interconnection capacity
- A changing generation mix[18]
- The development of the EU Target Model
- Greater demand side involvement

The SEM has proved far more resilient to radical changes in generation mix and increases in interconnection capacity than standard continental European markets over the last decade.

What are the characteristics of Ireland's Power System?

SSE would highlight a couple of additional physical and commercial characteristics.

Variable Penetration

Ireland has a large proportion of wind generation on its system, and limited variation in weather patterns across its various regions (and the market that it is connected to).

Compared to continental European systems, variability will be a bigger challenge in terms of short run optimisation and long run system adequacy.

Over the course of a typical week, there will be substantial variations in wind output. Over the course of a number of years, there can be relatively substantial variations in the load factor the wind generation fleet will provide.

Conventional new entry

In terms of conventional baseload generation, Ireland faces different constraints in terms of its generation mix. Whereas the GB market has a large proportion of coal plant retiring under the Large Combustion Plant Directive (LCPD), both Kilroot and Moneypoint have met their obligations under the LCPD. **However, due to the size of these conventional steam units relative to the island system, additional coal or nuclear[19] baseload capacity isn't really possible to build.** This effectively limits the addition of generic baseload capacity beyond Kilroot and Moneypoint to one technology type – combined cycle gas turbines.

Transmission constraints

The paper also points out that:

> *"[T]here are locational issues resulting from constraints on the transmission system that restrict the ability to transfer electricity from generation to*

[18] There has been a continuing rapid addition of renewable generation, particularly the penetration of variable wind, with 300MW being added in 2013 alone.
[19] Nuclear is also difficult to add to the all island system for non-economic reasons.

demand. In particular, there is currently a transmission constraint on the North-South corridor with expected reinforcement after 2017."

Making sure the TSO can obtain sufficient locational, physical and commercial information on units early in the scheduling process is going to be more important on the all-island system.

Effective portfolios?

Many of SSE's points on market power have been made in the section on the **Competition** criterion. There is one additional point to note on market structure.

Without structural changes, one generation company will continue to own a portfolio of around 4.5GW of installed capacity. Concentration in generation will not decline without structural intervention. **This means that there is a limitation on other producers building an effective generation portfolio.** The paper states that:

> *"AES now owns more than 1.5GW of oil-, coal- and gas-fired installed capacity[20]. Since acquiring the former Endesa assets, SSE currently owns more than 1GW of oil-fired generation alongside more than 500MW of wind installed capacity. Other generators operating in the all-island market include Bord Gáis, Viridian and Tynagh."*

Most utilities will effectively own a conventional power plant, renewable capacity and interconnection capacity. **This does not constitute an effective portfolio**. By this, we mean that most utilities will effectively be participating in the market with a single power plant, non-dispatchable generation and relying on interconnection capacity (if available) or a concentrated generation market to cover gaps through planned or forced outages at that plant.

Given these characteristics, what should the Irish Trading Arrangements look like?

Looking at the assessment criteria earlier and the physical and commercial characteristics of the all-island market, what would the energy trading arrangements look like?

Preserving the SEM through Option 4

Energy-only markets across Europe have not performed well against changes in the underlying physical generation mix and regulatory/political intervention over the last decade. These changes have led to:

- **Short run distortion –** ranging from loop flows to sustained periods of imbalance and negative pricing.
- **Long run distortion –** ranging from the undesirable stranding of modern, efficient assets to substantial capacity shortfalls at a member state level.

[20] Although this will be reduced by the closure of units at Ballylumford

There has been a flight away from energy-only markets, with Eurelectric acknowledging that:

"[I]n view of growing generation adequacy concerns due to increasing RES penetration and, in some cases, peak demand, a review of the current market design is becoming increasingly needed in some regions across Europe. [.....]CRM should be considered as an element of a new market design."

SSE believes that a split of capacity and energy is desirable in any new HLD, even if there is no explicit enforcement of the separation between the two through a BCoP.

Given that the explicit energy and capacity split under the existing SEM is familiar and proven, we believe that the existing design of the energy arrangements applied to the ex-post pool in Option 4 should be considered the benchmark against which other designs are compared. The successful, existing design is characterised by the BCoP and the long term price-based CRM arrangements.

This explicit split has resolved the indivisibility, price indifference and market power issues which characterise the Irish market.

Moving away from SEM to Option ?

Moving from the Single Priced SEM arrangements necessarily fragments participation across a number of different timeframes. The options taken forward may each have distinct forward, day-ahead, intraday, balancing and imbalance periods and prices. There is a risk that fragmentation will lead to 'thinly' traded markets[21].

This is a negligible risk in synchronous continental European 'Target Model' markets, but a very real risk in Ireland. Ireland is a small synchronous system with high variable uncertainty, market dominance issues and limited DC interconnection to other bidding zones. Thinly traded markets will expose consumers and participants to the exercise of market power.

There are solutions:

- **Explicit energy/capacity split** - preserving the current SEM market design through the SRMC ex-post pool and LRMC capacity arrangements under Option 4.

If it is decided that Option 4 cannot be delivered, or cannot be delivered with the existing structure – the BCoP and CRM have to change – then the market structure will have to look more like Option 1, 2 or 3.

Forward Period

The paper splits the forward period into **Internal** and **Cross-Border** trading. SSE would note that the **internal** section is primarily defined by arrangements at the DA and ID stage i.e. if DA participation is mandated, there can be no physical forward trading.

[21] This is a particular risk in the 'Irish' parts of any market – Forwards and Balancing.

Internal

As the competition section notes, one of the concerns with the current SEM is a lack of forward contract liquidity. This is particularly important for suppliers, who are effectively entering into fixed forward contracts with end customers for the supply of energy. **Financial forward contract liquidity will need to improve under any market design.**

The UK regulator, Ofgem, recently introduced **'Secure and Promote'** licence conditions focusing on three liquidity objectives:

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

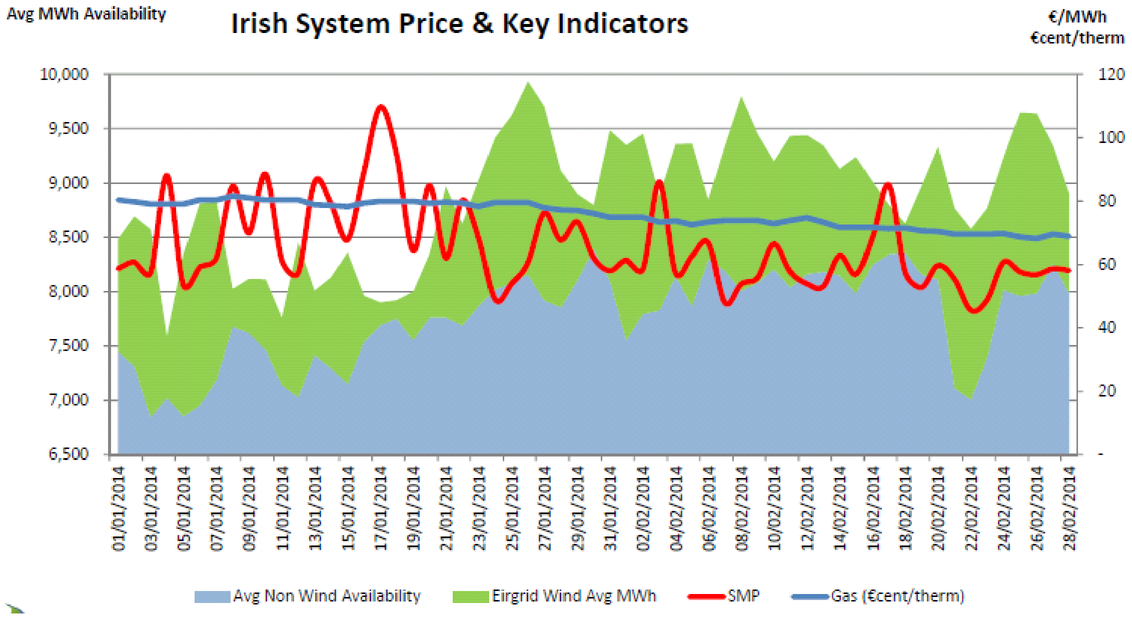
The effective near-term market relates more to the DA and ID periods, but the first two objectives (and solutions) could be applicable to Ireland. Currently, there are a couple of products that support supplier hedging:

- **Directed Contracts**, which are CfD contracts imposed by the RAs on generators with market power. These are offered in limited volumes on a rolling basis up to 5 quarters ahead. SSE Airtricity would be able to hedge a negligible percentage of its demand through DCs.

- **PSO-related CfDs**, we understand that the contracts that underpin these will expire in 2016/17. These provide approximately 0.82 TWh per quarter but will not be available in the new market.

- **Tullett Prebon OTC for Non Directed Contracts,** the OTC facility has been in operation for a number of years now and liquidity has not developed organically, as show in figures on volumes traded by participants.

The DCs and NDCs do not provide sufficient volume for supplier hedging under the existing SEM. Currently, suppliers can use a 'dirty hedge' i.e. one based around the purchase of NBP gas, which is a band-aid rather than a real solution. A HLD under Options 1 to 3 is far more likely to produce volatile out-turn prices that are less strongly correlated with a commodity index. This is shown in the figure below:



A gap develops, with smaller suppliers being unable to access forward products that provide adequate hedging opportunities. **The forward stage will require regulatory intervention to provide opportunities for smaller suppliers to compete in the market.**

In their decision on Market Power and Liquidity, the SEM Committee noted that:

> *"The SEM Committee considers liquidity developments best developed 'organically" through industry/market initiatives rather than being mandated by the RAs, and notes that most respondents to the draft decision agreed with this view.*
>
> *Hence the SEM Committee doesn't consider it appropriate at this time to establish a market maker facility in which a market participant (say ESB) would be required to continuously have a buy/sell facility for contracts at all times (e.g. via an exchange)"*

Forward liquidity has not developed organically, and considering that most of these energy market options will have a higher level of price volatility, there is a need for the SEM Committee to revisit this conclusion.

A regulatory intervention could impose a condition on participants with market power in supply and demand to act as a market maker, providing a minimum level of liquidity on an OTC platform with a narrowly limited bid offer spread. If a market maker posts an unreasonable bid or offer, they would be required to buy or sell at the opposite price. **SSE believes that this should translate into a sensible volume and price being offered for a reasonable volume of financial hedging products.** Once a market has sufficient liquidity, other participants would be happy to participate.

Cross-Border

Cross-border participation is more straight-forward – there is a choice of Physical Transmission Rights (PTRs) or Financial Transmission Rights (FTRs). As the paper notes:

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

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

SSE believes that the choice of whether to offer PTRs or FTRs in the forward stage should be left to the Interconnector Owner. PTRs are consistent with what is offered in other FUI interconnectors, and market design should look to ensure commonality.

Day-ahead

As previously noted, SSE believes that the DA market will be **structurally attractive** as a result of its timing and uniform auction characteristics, which provide a reasonable notice period for conventional generators and a robust reference price for the settlement of any financial contracts.

However, forward physical contracts settled by generators and suppliers within Ireland are inherently bilateral. SSE would see a risk that allowing them could mean generators with market power could withhold physical capacity from registered market places.

Mandating participation at the DA stage is manageable and at the very least the RAs must apply the concept of **exclusivity** to the DA and ID markets. By making the two registered market places the only points at which market participants can strike firm physical contracts, you can ensure that those markets are sufficiently liquid.

Unit or Portfolio?

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

There are two reasons that it is difficult and unattractive to separate out the physical and technical characteristics of electricity generated by conventional stations from the commercial characteristics:

- As the consultation paper notes, there are a number of non-energy related issues that are important in the management of a small synchronous island system with high variable renewable penetration. **Physical and locational characteristics must be provided to the TSO from any market with some element of self scheduling.**

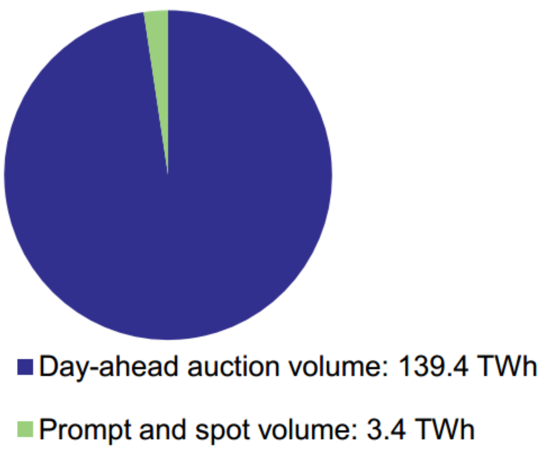
- Most utilities will be participating in the market with a single power plant, non-dispatchable generation and interconnection capacity (if available) or a concentrated generation market to cover gaps through planned or forced outages at that plant. This does not constitute an effective portfolio. **All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

The retention of unit bidding for conventional units would provide value to the TSOs, most participants and the RAs. **Allowing wind generation to participate on a portfolio basis would minimise complexity for market participants, TSOs and RAs and lower transaction costs and entry barriers for small wind participation.** Wind portfolio participation also preserves the current aggregation arrangements which have facilitated wind entry.

Intraday Period

The concept of exclusivity should also apply to the ID market. This will ensure some level of liquidity. SSE does not believe that there is any benefit to the TSO or market participants in allowing intraday adjustments within portfolios. How liquid the ID market will be is unclear due to delays in the delivery of the European Intraday Platform[22].

A comparison could be drawn between Elbas in the Nordic region and the N2EX platform in the UK[23]. The UK has low volumes flowing through the continuous markets, whereas Elbas has seen a very slight increase over time. It is difficult to assess whether this is a result of market structure, behaviour or design. GB volumes for 2013 are shown below:



[22] We understand that power exchanges have selected an IT provider and are aiming for a go-live by the end of 2014, but there have been no clear deadlines available yet.
[23] Both platforms are now run by Nord Pool Spot.

Balancing and imbalances

The design of the Balancing Market and imbalance will influence participant behaviour in the time periods beforehand. As stated previously, we believe that the design of these has not been particularly well signalled in the consultation paper. Under Options 1 and 3, the paper simply states:

> *"This imbalance price is set at the price of the marginal energy balancing action activated by the TSO in each period. Either a single price or a dual price imbalance settlement can be accommodated."*

There are a couple of different characteristics that will influence behaviour:

I. **Liquidity – the variety of incremental and decremental offers available to the TSO**

II. **Methodology – the methodology for the calculation of the imbalance price**

These are briefly explored under each of the different options.

Liquidity

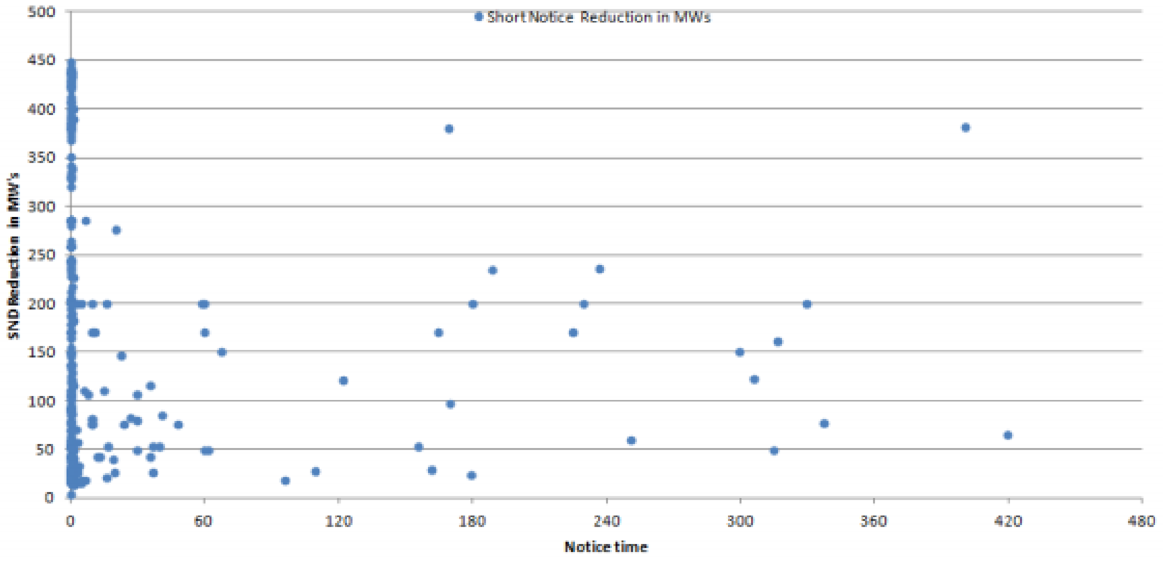
Under Option 1, the paper states that

> *"Participation in this balancing mechanism is voluntary up to the gate closure of the ID market but mandatory after the ID GC. Mandatory in this timeframe means that all market participants with technical capabilities to regulate either upwards or downwards within the time between ID GC and real-time must participate."*

This is in contrast to Option 3, which would mandate participation in the balancing mechanism from the DA stage onwards. The TSO's paper[24] on dispatch notes that there will be a large number of short notice changes in availability declarations over the course of a year, as shown in the next figure:

[24] Dispatch Model for the All Island Market/Transmission System (2012), Eirgrid/SONI

Chart 2 2011 All island Short Notice (< 8Hours) Changes in Availability Declarations (522 occurances)



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

SSE would also request clarity in the Proposed Decision Paper on whether the TSO would be able to use the continuous ID platform for energy balancing actions.

Methodology

The methodology for tagging non-energy actions and calculating imbalance prices will be (necessarily) complex, and this response doesn't seek to go into great detail. However, SSE would stress that an imbalance price set at the marginal 1MWh (as in GB) might create some issues in the Irish market. The TSOs paper states that:

> *"The number of individual generators i.e. the number of parties self dispatching will make the larger system less prone to individual party balancing errors. The overall error produced by a large number of independent elements will be relatively smaller than from a smaller number when considered collectively."*

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

Even in the existing SEM which 'dampens' price volatility, there can be substantial differences between ex-ante and ex-post SMP as a result of balancing energy actions[25]:

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

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

Given market power concerns and the likely quantum of overall system balancing error, SSE would recommend a single pricing methodology, calculated over a Price Average Reference (PAR) higher than 1MWh i.e. an average of 100MWh of actions.

Balancing and wind generation

Assuming that conventional units would be bidding on a unit basis, and wind units would be participating on a portfolio basis, imbalances for wind should also be settled on a portfolio basis. To settle wind imbalance on an individual unit basis would unnecessarily penalise smaller wind generators: they would receive much higher balancing discounts on Power Purchase Agreements (PPAs) to account for the larger forecast error at a unit level.

We assume that wind has a firm physical position, it will not be considered a 'price taker' in the balancing arrangements, and will be able to bid in incremental or decremental bids that reflect the value of changes to that physical position.

[25] Among other factors

CONCLUDING REMARKS

SSE believes that two different types of design could meet the RAs assessment criteria. An explicit CRM would be required under both.

We assume that **Option 4** retains the structure of the current energy and capacity arrangements in the ex-post pool including the CRM design, Bidding Code of Practice and uplift arrangements. This design has performed far better than continental European markets in withstanding radical physical change and political and regulatory intervention, and we favour its retention. **At the very least, it should be the benchmark against which other options are measured.**

If the CRM design and BCOP cannot be preserved in **Option 4's** ex-post pool, then arrangements that resemble **Option 3** (with some variations and clarifications in the Forward, Day-Ahead and Balancing time periods) would suit the Irish market far better than either **Option 1** or **Option 2** as defined in the consultation paper. Given that bidding controls could not be designed or enforced under these trading arrangements, the explicit CRM that would accompany a variation of **Option 3** should be a volume based central auction.

ANNEX I: RESPONSES TO CONSULTATION QUESTIONS

PURPOSE OF THIS DOCUMENT

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

If **Option 4** retains the structure of the current energy and capacity arrangements in the ex-post pool including the CRM design, Bidding Code of Practice and uplift arrangements, it would be SSE's preferred option.

If the CRM design and BCOP cannot be preserved in **Option 4's** ex-post pool, then arrangements that resemble **Option 3** (with some variations and clarifications in the Forward, Day-Ahead and Balancing time periods) would suit the Irish market far better than either **Option 1** or **Option 2** as defined in the consultation paper.

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

An explicit CRM is needed in the HLD. Ireland faces **indivisibility, price indifference** and **market power** issues. These cannot be effectively (or attractively) mitigated in an energy only market. This is covered in the **capacity** section of the paper.

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

Under **Option 4,** the existing price based CRM with BCOP would be our preferred choice – it is proven, clearly defined and familiar to investors.

A volume based central auction would better fit any other set of energy trading arrangements.

TOPICS FOR THE HIGH LEVEL DESIGN OF ENERGY TRADING ARRANGEMENTS

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

This section captures design characteristics under each of the trading time periods. SSE would request that further detail is provided and consultation carried out on balancing and imbalance pricing arrangements.

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

While the Network Code on Electricity Balancing is not yet finalised, we would expect more detail on compliance with its provisions in the proposed and final decision papers.

SUMMARY OF THE OPTIONS FOR ENERGY TRADING ARRANGEMENTS

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

Security of supply: SSE believes that this criterion cannot be accurately assessed by the TSO alone, and cannot be assessed without a defined CRM. The decision chains that lead to changes in the level of capacity on a system are iterative in nature, and can only be assessed when the final structure of the CRM and trading arrangements are made clear. However, we have provided evidence on security of supply in the GB market and some modelling on the Irish market.

Efficiency: Interconnector flows are fundamentally economic, rather than technical. Assessing efficiency becomes a choice between the extent to which efficient interconnector flows can be assumed under any option and the impact of those interconnector flows on technical dispatch. SSE believes that an HLD design with a integrated scheduling process or self commitment can deliver efficient dispatch.

Adaptability: The processes for governance and market development have not been defined (and should not be defined) under any of the HLD options. We would agree that *"adaptability is typically not a major distinguishing feature of different energy trading arrangements."*

ADAPTED DECENTRALISED MARKET

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

The Adapted Decentralised Market design would need to be modified to provide for:

- An exclusive intraday market
- No internal physical forwards
- Mandatory BM participation

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

We do not favour the Adapted Decentralised Market as defined in the consultation paper. Our preferred options are covered in the **energy** section of our response.

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

We do not believe the Adapted Decentralised Market as defined in the consultation paper would serve the long and short term interests of consumers. Our preferred options are covered in the **energy** section of our response.

MANDATORY EX-POST POOL FOR NET VOLUMES

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

The Mandatory Ex-post Pool for Net Volumes design would need to be modified to provide for a balancing market rather than mandatory ex-post pool. This would fundamentally change the design to resemble Option 1 or 3.

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

We do not favour the Mandatory Ex-post Pool for Net Volumes as defined in the consultation paper. Our preferred options are covered in the **energy** section of our response.

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

We do not believe the Mandatory Ex-post Pool for Net Volumes as defined in the consultation paper would serve the long and short term interests of consumers. Our preferred options are covered in the **energy** section of our response.

MANDATORY CENTRALISED MARKET

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

The Mandatory Centralised Market design could retain PTRs without any impact on effectiveness. Assuming that no internal physical forward trading is available and both DA and ID markets are exclusive, the mandation requirement at DA stage could be potentially be relaxed over time.

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

The Mandatory Centralised Market could perform against the RAs Assessment Criteria. This is covered in the **energy** section of our response.

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

The Mandatory Centralised Market could serve the long and short term interests of consumers. This is covered in the **energy** section of our response.

GROSS POOL – NET SETTLEMENT MARKET

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

The paper states that:

> *"A full ex-post unconstrained pool (as per current arrangements) produces a single ex-post price. As this is a net settlement process, this price is applied to all volumes scheduled in the ex-post pool that have not been matched in the ex-ante markets."*

As we understand it, this means that the ex-post unconstrained pool will produce a single ex-post price using the same inputs as the current SEM design i.e. the complex unit based bids will be subject to BCOP bidding restrictions and there will be a distinct split between energy and capacity. This is critical to the design of the Gross Pool – Net Settlement Market.

If the unconstrained pool did not apply an explicit separation between energy and capacity elements as in the current SEM, we would see no value in its retention. It would be vulnerable to the exercise of market power, and a restrictive mandatory supplement to the financial ex-ante markets.

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

The Gross Pool – Net Settlement Market is difficult to qualitatively assess without a commitment to preserve both the energy and capacity arrangements. We have assumed that both 'integral' elements are in place.

If that is assumed, we would add that both the Security of Supply and Competition criteria are proven as a possible strength under this option.

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

Assuming a market with a explicit energy and capacity elements, the Gross Pool – Net Settlement Market could serve the long and short term interests of consumers. This is covered in the **energy** section of our response.

CAPACITY REMUNERATION MECHANISMS

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

An explicit CRM is needed in the HLD. Ireland faces **indivisibility, price indifference** and **market power** issues. These cannot be effectively (or attractively) mitigated in an energy only market.

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

Yes, these effectively capture the primary design differences between any CRMs. However, we would note that a Strategic Reserve effectively works as an ancillary service rather than a CRM.

STRATEGIC RESERVE

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

A Strategic Reserve mechanism would not resolve any of the issues an explicit CRM should. This is covered in the **Capacity** section of our response.

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

In addition to the points made in the response, SSE would add that a Strategic Reserve mechanism would be extremely difficult for storage, DSR or interconnection to participate in. It would also distort price signals within the residual energy market that non Strategic Reserve contracted plant would need to participate in.

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

A Strategic Reserve Mechanism is effectively an ancillary service. It could fit with any energy trading arrangements, but its introduction would undermine market functioning.

LONG-TERM PRICE-BASED CRM

24. Are there any changes you would suggest to make the design of a long-term price-based CRM mechanism more effective for the iSEM (for instance a different choice for one or more of the topics?)

The paper states that:

"This total resulting payments to all available capacity in any month may not equal the initial monthly pot as there will be a deviation between forecasting available and resulting available capacity as well as forecasted demand and actual demand. Therefore a mechanism will need to be put in place to deal with under/over recovery – this cannot be done by having an ex-post element in the price as this would distort cross-border flows.

The 30% ex-post element could be changed to a 30% ex-ante day-ahead element which would minimise forecast deviations. It should be relatively simple to deal with the under/over recovery on an annual basis through a k factor.

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

The existing price based CRM is proven, clearly defined and familiar to investors. It also has the benefit of providing the RAs with some certainty as to how much ensuring adequate capacity would cost the consumer.

The paper states that:

"The relative certainty of the annual pot comes however at the expense of shorter term price signals [....]. Consequently, the scheme may provide relatively greater benefits to more 'inflexible' and baseload plant than flexible resources (e.g. generation, storage, demand side or interconnection)."

We would challenge this assertion. The existing CRM has brought forward more flexible resource than markets with 'stronger' short term price signals. In particular, it has rewarded and incentivised DSUs and interconnection better than markets which theoretically should have stronger short-term price signals.

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

The long-term price based CRM as currently defined fits with the Gross Pool – Net Settlement Market, assuming a commitment to preserve both the SRMC energy and LRMC capacity arrangements. It may not fit with any of the other energy options.

SHORT-TERM PRICE-BASED CRM

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

The description in the consultation paper accurately describes the differences between long and short-term price-based CRMs. A short-term price-based CRM mechanism could exacerbate physical and market structure issues in the SEM. This is covered in the **Capacity** section of our response.

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

Efficient short-term price signals would not necessarily be more favourable for flexible resources. This assumes that investors in new flexible resource would be better than baseload providers in managing the cash flow volatility implicit in a short-term CRM. This might be true for an existing (committed) OCGT, but will not be true for a new flexible unit seeking to displace inflexible resource.

The paper states that:

"Also, the high responsiveness of the capacity price to the capacity margin does also leave room for potential gaming because market participants are in a position to withhold capacity so that capacity prices rise."

Considering the level of interconnection and generation concentration within Ireland, this would be an even greater design concern than under the old England & Wales pool which employed a similar mechanism.

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

A short-term price-based CRM could fit with any energy trading arrangement, but it would be unattractive for a number of reasons outlined in the **capacity** section.

QUANTITY-BASED CAPACITY AUCTION

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

The description captures a generic design for a quantity-based Capacity Auction CRM. SSE has included its own basic HLD in **Annex IV** of our response. One concern is that the consultation paper states:

"Capacity auctions are market-wide in principle. However, there could be specific provisions on technical characteristics (especially in terms of capability) in the type of generation and demand that can partake in the capacity auction."

Specific provisions on technical characteristics are a matter for the TSOs Grid Code, rather than being conflated with HLD market design. If you are able to provide capacity to the system, you should be able to participate in the capacity auction.

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

The paper states:

"Unlike the price-based CRM schemes, Capacity Auctions do not offer a short term capacity price signal and can actually dampen energy prices, which can lead to inefficient signals to flexible providers (such as the demand side and interconnection, who can respond to those signals)."

This simply means that flexible providers can bank on a stable long term rather than a volatile short term revenue stream. These units are more dependent on accessible scarcity value than baseload units and in reality benefit more than baseload units from bankable, predictable revenue streams to supplement volatile balancing market revenues.

This can be seen in deployment levels of DSR in SEM vs. deployment of DSR in BETTA. A balancing market will still pick and reward flexible providers of capacity if flexibility is needed.

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

A quantity-based Capacity Auction CRM would better fit with Options 1 or 3. The balancing market should provide a proper value for flexibility, offsetting any dampening of short term prices.

QUANTITY-BASED CAPACITY OBLIGATION

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

The description of the Capacity Obligation includes a suggestion that:

"In order to improve transparency, liquidity and market power mitigation measures, it may be seen as desirable to enforce that capacity certificates can be obtained through centrally organised auctions with a requirement for gross portfolio bidding (i.e. a vertically integrated company must separately bid in their requirement and their supply)."

SSE would agree with this design change, but this effectively alters the quantity-based Capacity Obligation CRM to a quantity-based Capacity Auction.

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

The concerns expressed around transparency, liquidity and market power mitigation have not been included in the initial assessment. SSE believes that a Capacity Obligation CRM would have issues with each of these.

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

SSE does not favour a quantity-based Capacity Obligation CRM. However, it would better fit with Options 1 or 3 where the balancing market would provide a proper value for flexibility, offsetting any dampening of short term prices.

CENTRALISED RELIABILITY OPTIONS

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

No, the design of the Centralised Reliability Option CRM is straight-forward.

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

The paper notes that:

"It might be that such a scheme will be more difficult to be perceived as delivering sufficient capacity as it is based around financial payments rather than physical delivery."

From an industry standpoint, both generators and suppliers (and network companies) have a reputational interest in being able to provide a secure supply of energy.

We would expect that the RAs clarify that some form of physical backing would have to be required by issuers. It is fundamental that any parties which would want to provide a reliability contract is a credible counterparty i.e. that they can afford penalty payments and/or provide the appropriate amount of capacity.

If physical backing was introduced, it is difficult to see why a quantity-based Centralised Reliability Option CRM would be more attractive than the more familiar, and similarly efficient quantity-based Capacity Auction.

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

It is unclear how Centralised Reliability Options would work across fragmented markets. Peaking generators or DSR would not typically be accessing a DA reference price. SSE does not favour this CRM option.

DECENTRALISED RELIABILITY OPTIONS

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

Without a central obligation to purchase capacity options from market participants, it is impossible to see how a market would develop organically, or how that market could deliver sufficient capacity.

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

The paper notes that:

"The mechanics are more complex when compared to the centralised variant, and in addition there is no experience in another market."

Both of these are concerns. The second statement is particularly important – this option could develop organically in energy only markets, but it has not. This is because it does not adequately resolve the missing money problem.

As with the Centralised Reliability Option CRM we would expect that the RAs require some form of physical backing from issuers. It is fundamental that any parties which would want to provide a reliability contract is a credible counterparty i.e. that they can afford penalty payments and/or provide the appropriate amount of capacity.

If physical backing was introduced, it is difficult to see why a quantity-based Decentralised Reliability Option CRM would be more attractive than the more familiar quantity-based Capacity Auction.

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

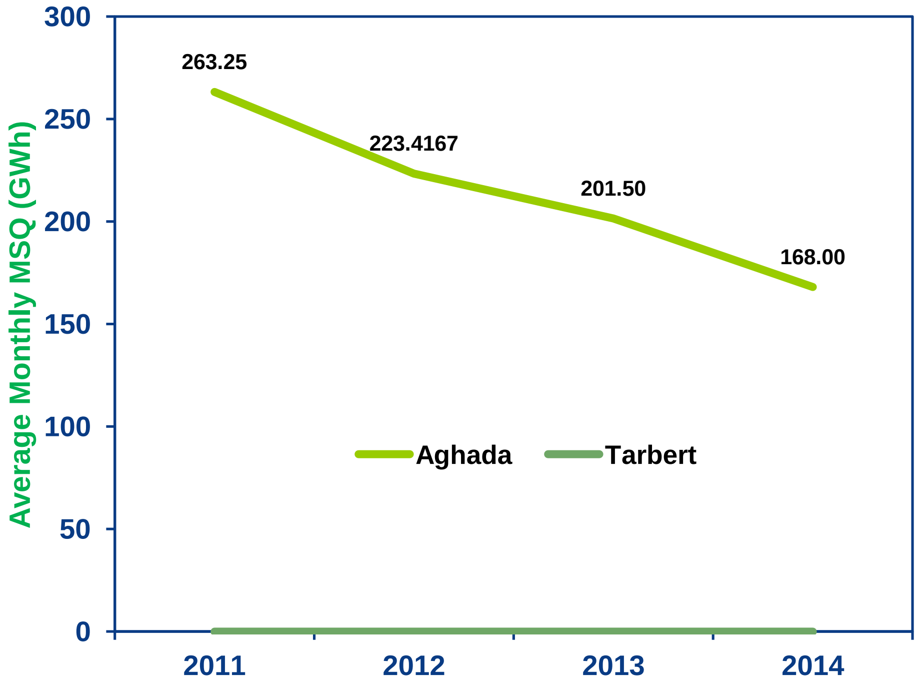
It is unclear how Decentralised Reliability Options would develop without a central requirement to purchase a volume of capacity. SSE does not favour this CRM option.

ANNEX II: MARKET STRUCTURE AND MARKET POWER

Asset Strategy and Market Structure

Despite the CER-ESB Asset Strategy[26] being agreed in November 2006, there has been no significant change in the underlying market structure in the Ireland. While the Asset Strategy provided for the sale of peaking capacity, the closure and divestment of existing power plant, it also provided for the construction of a new 435MW CCGT at Aghada. The transfer of installed capacity away from ESB has not resulted in any transfer of market volumes that would reduce wholesale concentration.

Tarbert vs Aghada MSQ



'Organic' OTC liquidity?

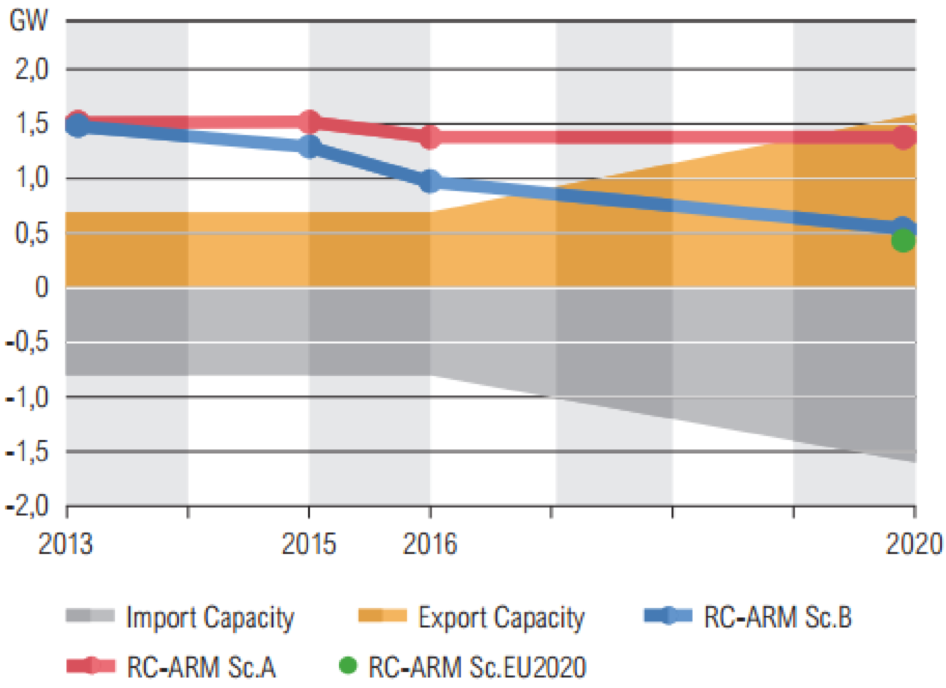
We cannot provide detailed information from the Tullett Prebon OTC auction platform due to data protection issues with counterparties. However, our own observations indicate that 50% of the total volume over the last 6 months has been provided by AES and SSE. Other volumes have been either transacted at prices significantly above expectations of market prices.

Forward hedging will continue to be a major concern for suppliers (particularly smaller suppliers) under any of the energy market designs.

[26] CER-ESB Detailed Agreement on Asset Strategy (2007), Commission for Energy Regulation

ANNEX III: TSO FORECASTS AND REVENUE ADEQUACY

The ***ENTSO-E Scenario Outlook & Adequacy Forecast 2013 – 2030*** shows that Ireland should enjoy a relatively healthy capacity margin up to 2020, but this assumes that the second North-South Interconnector is in place from 2017[27]. The only known generating unit closures are based on 'hard' constraints on continued operation i.e. closures under the Industrial Emissions Directive (IED).

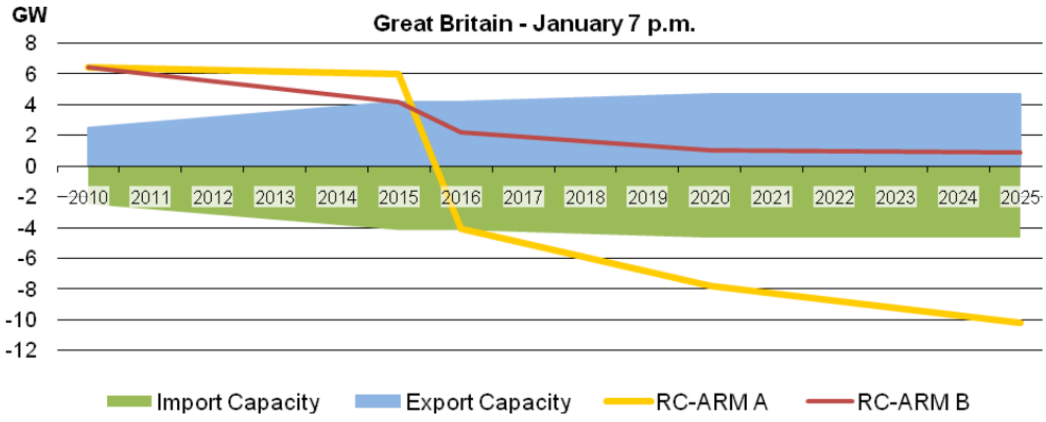


Will this TSO forecast be accurate? TSO forecasting in Great Britain provides a useful example, given that the GB system has rapidly shifted from a position of surplus margin to scarcity in just 3 years.

Under the ***ENTSO-E Scenario Outlook & Adequacy Forecast 2010 – 2025***, published just 3 years ago, the TSO expected that under a 'Business As Usual' scenario, investment in gas plant will maintain an adequate de-rated capacity margin, offsetting the significant capacity of plant closed from 31st December 2015 under the LCPD.

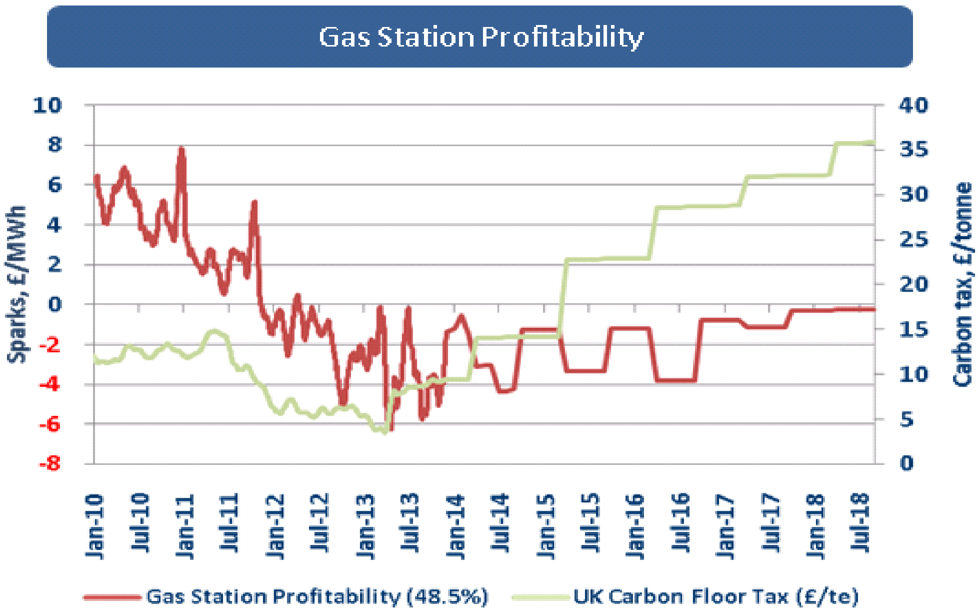
27 This expected commissioning date has been in place in the last 3 Generation Capacity Statements issued by the TSO, despite substantial further delays to the project. The 2011-2020 capacity statement noted that: *"The NSIC is expected to be completed between 2015 and 2017."*

5.14 GB – Great Britain



Only under ***RC-ARM A***, where no lifetime extensions are agreed for the nuclear fleet and the only new generation included in the adequacy assessment are projects currently reported as ***under construction*** does an issue emerge. This was considered an extremely bearish view.

In reality, ***Scenario 1 (RC-ARM A)***[28] has been much closer to the truth than ***Scenario 2 (RC-ARM B)***. Plant closures under the LCPD have happened sooner, and mothballing of unprofitable gas plant has happened far faster than the TSO predicted. The figure below shows Gas Station profitability for a CCGT, assuming that the Carbon Floor Price followed the initially published trajectory[29].



Market participants with existing gas generation units or gas investment projects have therefore primarily looked to assess:

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[28] RC-ARM A takes into account the commissioning of new power plants considered as certain and the shutdown of power plants expected during the study period, if no new investment decisions were to be taken in the future.

[29] As of the 19th March 2014, the Carbon Floor Price has been frozen in the UK Budget 2014, further impacting the commercial viability of gas stations.

- Development, implementation date and expected out-turn of the UK's Capacity Mechanism

- Coal Switching Price (CSP) Premium to National Balancing Point (NBP) gas

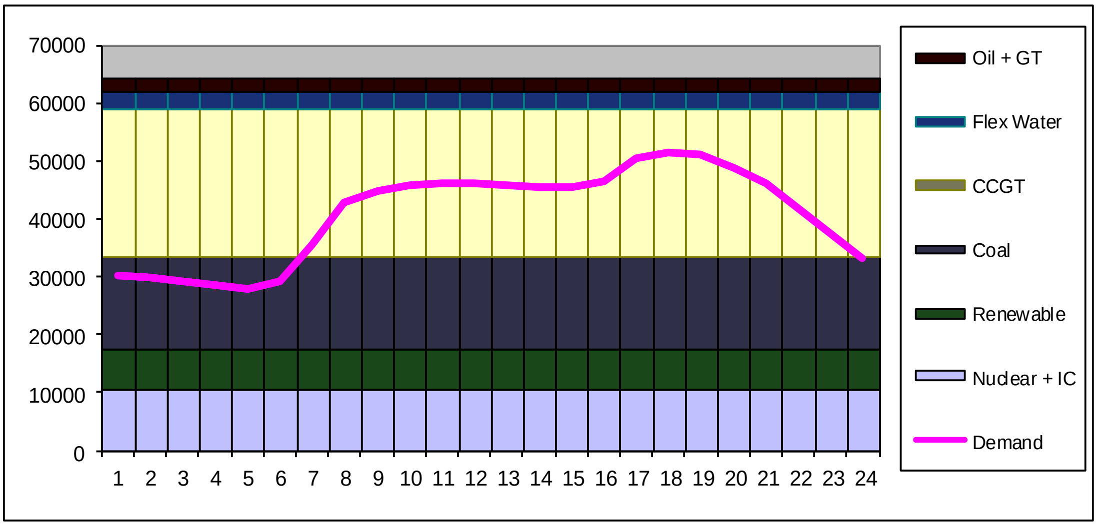
- Behaviour of market participants with existing generation plant or planned investments

- The 'firmness' of the UK Government's commitment to a Carbon Floor Price trajectory

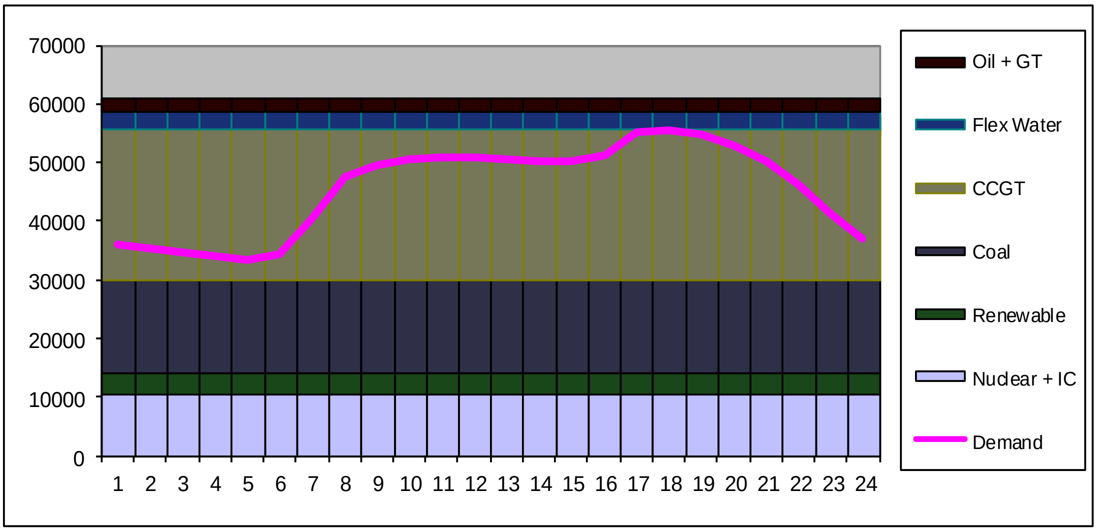
These are iterative in nature. The UK Government's commitment to a Carbon Floor Price trajectory has been influenced by retail price levels, market participants have chosen to retire or mothball capacity based on the behaviour of competitors and underlying economic fundamentals etc. **The net result of these decision chains has been that the UK was forced into a position of system scarcity far sooner than the TSO predicted.**

This was illustrated in Week 50 of 2013 last year, as shown in the figures below:

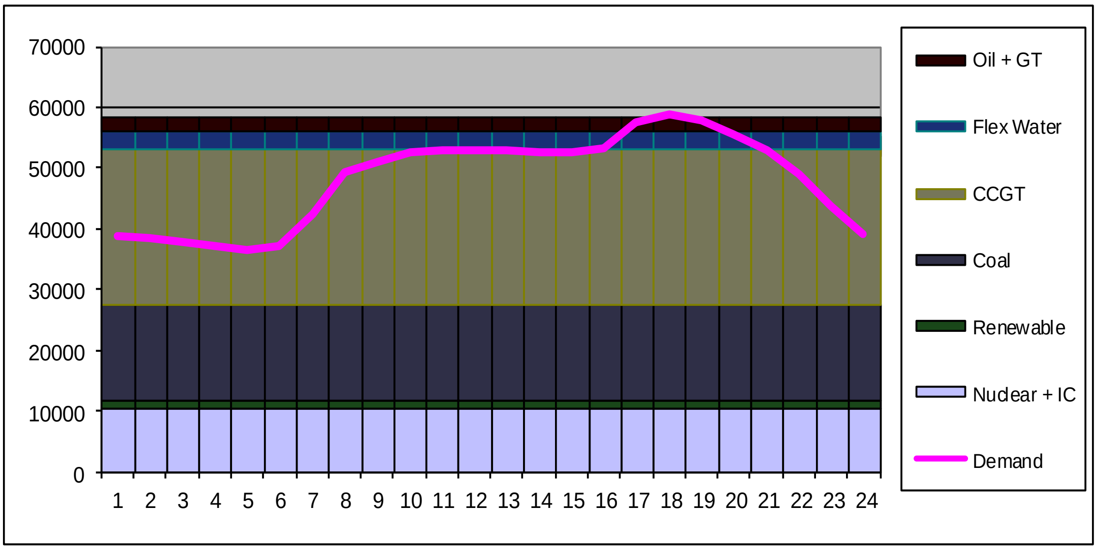
Scenario 1: Low Demand, High Wind



Scenario 2: Normal Winter Peak Demand, Average Wind



Scenario 3: Cold Weather Demand, Low Wind



Winter 2013/14 was unusually mild. Under any other scenario, the GB system would have struggled to meet demand in Week 50 2013, 2 years after the TSO had forecast a healthy capacity margin until at least 2015.

So, can a TSO provide a holistic assessment of Security of Supply in the All-Island Generation Capacity Statement (or similar)?

Given the experience in GB and other European Markets SSE would suggest that the answer is no. Market participants also struggle to provide accurate information – the iterative process that leads to closures, mothballing or investment decisions only begins at the point at which information on market design characteristics become firm. However, we have provided some high level figures to look at plant revenues and costs under current Irish system characteristics.

ANNEX IV: VOLUME BASED MECHANISM STRAW MAN

Timescale

The introduction of a volume based mechanism should coincide with the implementation of the new market. The first auction should deliver a value for capacity from 2017/18 onwards, with auctions being run as soon as practical.

Eligibility

The capacity market should be open both to new and existing capacity with all forms of capacity treated equally from an economic point of view.

Volume determination

The desired volume of capacity should be linked to a reliability standard. Any decisions to procure less volume than required must be based on an open and transparent methodology that is clearly understood by generators and investors.

Auction design

The Regulatory Authorities with assistance from the TSO would determine the volume of capacity required to meet the reliability standard ahead of delivery.

Price determination

A clearing price auction would give a better signal of the market price for capacity since a uniform price would be paid to providers of capacity.

The clearing price would be the offer price of the highest accepted offer and would be paid to all capacity resources that have bid into the auction at or below this price.

Secondary market

A secondary market should exist to allow capacity providers to trade capacity on a shorter-term basis. This would be needed to allow primary market participants some flexibility in meeting their contracted capacity level, for example in the case of plant failure or unexpected closure.

Treatment of non-generation capacity

Capacity provided by demand-side response (DSR) and storage technologies is treated no differently to other generation technologies. However, only non-generation resources that are dispatchable in real time are eligible to participate.

State Aid Guidelines

This volume-based capacity market would satisfy the criteria likely to be imposed by the European Commission for State Aid clearance[30]. Treatment of interconnected

[30] Assuming that the European Commission's binding draft State Aid Guidelines do not change substantially from their current form. This approach would also have the advantage of regional coordination, and the UK's Department of Energy and Climate Change will have done most of the groundwork in terms of State Aid clearance.

capacity would be simple in the short to medium term, as plant supported under the GB capacity mechanism would not be eligible for payments under the Irish mechanism. In the long term, the Interconnector owner (or agent) could take on the capacity obligation and facilitate the delivery of that obligation at times of system stress.