# Response by Energia to the SEM Committee Draft Decision SEM-14-045 and Initial Impact Assessment SEM-14-046

*Integrated Single Electricity Market (I-SEM)*

*High Level Design for Ireland and Northern Ireland from 2016*

25 July 2014

# 1 Executive Summary

In this response we provide our considered views, with evidential support, on the high level design (HLD) draft decision for trading energy and remunerating capacity under I-SEM, as presented in draft decision paper SEM-14-045 and supported by the initial impact assessment SEM-14-046. The final HLD decision will have long lived consequences for the consumer well into the next decade and any inefficiency, unwarranted increase in commercial risk or poor specification inherent in the market design will raise costs and prices of electricity and leave consumers exposed to the risk of under-investment in capacity. Given these long term implications, Energia recommends that the SEM Committee should not move forward with a final HLD decision that is not supported by robust evidence or without having considered all its implications for I-SEM consumers relative to viable alternatives.

**Shift in Regulatory Approach to Market Power and the Small Market Problem**

The proposed I-SEM design (in terms of its energy trading arrangements and capacity remuneration mechanism) represents a regulatory U-turn in relation to fundamental consumer concerns pertaining to the All-Island market – e.g. promotion of competition and market power mitigation. Energia note, however, that the underlying market conditions have not materially changed since 2007. The I-SEM will remain a small market characterised by the dominance of ESB (state owned company) in generation and supply. This cannot be dismissed with vague references to enhanced interconnection and market integration, as validated by CEPA as recently as 2010[1] and accepted by the SEM Committee in 2012 in their decision on ESB horizontal reintegration[2], and which is further explained and reinforced by NERA in their report submitted with this response.

It is clearly evident, from review of the draft decision and initial impact assessment, that misguided assumptions regarding compliance with European energy policy and a desire for so called 'market based' solutions are key drivers of this shift in regulatory approach. It should be noted, however, that market based solutions only work in competitive markets (which I-SEM clearly is not) and that a fully competitive market – i.e. a market that needs no regulatory intervention - is an idealised concept rather than a reality. This is borne out in the NERA report.

At the 17 June 2014 I-SEM workshop in Dundalk the regulatory authorities (RAs) introduced Dr Pablo Rodilla as an expert speaker to present his academic research on international experience with capacity mechanisms. He states in his research that "[t]he main aim of our work has been to highlight the fact that the final problem is not the market approach itself, but the lack of adequate regulatory mechanisms to deal with the complications that real life markets may present"[3]. This is good advice but

[1] CEPA (2010), 'Market Power and Liquidity in SEM: a report for the CER and the Utility Regulator', Cambridge Economic Policy Associates, 15 December 2010.
[2] SEM Committee (2012a), 'SEM Market Power & Liquidity, A SEM Committee Decision Paper, SEM-12-002, 1 February 2012.
[3] Batlle, C., Rodilla, P. (2010), "A critical assessment of the different approaches aimed to secure electricity generation supply", IIT Working Paper IIT-10-017A, July 2010 (version subsequently published in Energy Policy, vol. 38, iss. 11, pp. 7169-7179, November 2010).

that has been ignored in the I-SEM decision. Rather the proposed decision signals a desire on the part of the RAs to step away from the market and to rely on 'presumed' competition and liquidity for delivery of efficient outcomes. NERA has described this approach as "a subjective leap of faith".[4] To the extent that the resulting market design favours ESB (a dominant state owned company) and provides a dividend to the Irish government, this offers no recompense to the NI consumer.

**Target Model Compliance**

Scheduling the I-SEM exclusively through EUPHEMIA, as proposed in the draft decision, is not a requirement of the EU Target Model, nor does it guarantee an efficient day-ahead market outcome or efficient market coupling as noted by both NERA and Baringa. It therefore seems imprudent for the SEM Committee to adopt such an unnecessary and extreme position in relation to the implementation of the EU Target Model without first conducting rigorous testing to ensure the proposed design (which would be unique within Europe) is in the long-term interests of I-SEM consumers.

**Independent Third Party Assessment**

Viridian commissioned NERA to provide an independent third party evaluation by industry experts of the soundness of the HLD draft decision and the quality of the impact assessment which informed it. NERA have concluded as follows:

***"We found many problems in the quality of the appraisal used to justify the SEM Committee's choice of option 3 and Reliability Options. In particular, we found areas where the appraisal is subjective, selective and biased, with the effect that the discussions are prejudicial and do not provide a proper basis for selecting an electricity market design, putting the Decision at risk of legal challenge. We conclude that the SEM Committee's decision is unsound and that market participants cannot be confident that the SEM Committee has reached the right decision on a high level design for the I-SEM"*** (Executive Summary, page iii)

In light of this conclusion, which is evidentially substantiated by their report, NERA have stated that the current propose "… Decision [is] at risk of legal challenge."[5] To mitigate this risk they stipulate the requirements that need to be met to allow the SEM Committee to reach a robust final HLD decision. Energia would stress that NERA are willing to discuss their report with the SEM Committee or government departments. Energia would be willing to be excluded from these discussions.

Given the conclusions of the NERA report Energia request a third party review of the recommendations provided to the SEM Committee (and the supporting impact assessment that will inform the final HLD decision) and recommend that a 'Quality Assurance' role for an independent third party is included in the I-SEM project going forward.

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[4] "I-SEM Draft Decision SEM-14-045: A Review", para 221, p.50.

[5] "I-SEM Draft Decision SEM-14-045: A Review" in Conclusions section of the Executive Summary on p.iii

### I-SEM Project Timetable and Revised Project Plan

It is in the interests of consumers, participants, regulators and governments to get the market design and testing right. Given the long term implications for the consumer, this objective must override objectives to meet short term deadlines and project milestones. If the previous project plan published in February 2013 was realistic, the new plan must change the implementation date by 5 months to reflect the delays experienced to date and the importance and magnitude of the work that remains to be done. Energia would also stress that the industry urgently needs a revised project plan to be published as soon as possible.

### Scheduling Risk under the Proposed Design

Our response is also supported by a Baringa report which was commissioned on a multi-client basis by Viridian, Tynagh, AES and Bord Gais Energy. Its focus is on scheduling risk under the proposed energy trading arrangements and it concludes that the proposed design:

- Does not provide generators with the ability to fully mitigate their commercial and technical risk;
- Is likely to increase generators exposure to scheduling risk (further amplified by the proposed implementation of a form of reliability options as the I-SEM CRM);
- Is likely to result in inefficient price volatility and scheduling in the DAM;
- Will increase costs to I-SEM consumers through:
    - Increased premiums on forward contracts
    - Reduced liquidity in forward markets (undermining retail competition)
    - The inefficiency of DAM outcomes;
- Favours large, diverse generation portfolios – e.g. ESB;
- Makes effective market power mitigation difficult.

### Importance of Robust EUPHEMIA Testing

We acknowledge the work carried out by the regulatory authorities on EUPHEMIA order formats (but we are disappointed that this critical work was conducted ‘behind closed doors’ without industry involvement) and strongly support the decision communicated at the industry workshop on 17 June 2014 to test the outputs of the EUPHEMIA algorithm for the I-SEM DAM.

Given the importance of the efficiency of the DAM to the integrity of the proposed HLD, it is essential that rigorous, inclusive and transparent testing is completed prior to the final decision on the HLD and that there is full disclosure of test data. This will provide market participants with confidence in the energy trading arrangements and thereby promote forward market liquidity prior to market go live (a stated aim of the SEM Committee in the proposed HLD decision paper).[6]

As evidenced by the Baringa and NERA reports, to adequately test the efficiency of the DAM under the proposed design testing must include the dynamic modelling of

[6] Cross reference paragraph 6.4.6 on P.39 of the Draft Decision Paper.

generator bidding strategies in relation to changing I-SEM dynamics, including the bidding strategies of other generating companies. Testing needs to be completed using Euphemia (and Euphemia order formats) to ensure that the hypothesis that "generators will 'learn' how to bid to achieve a consistently efficient outcome"[7] in the context of the I-SEM is verified evidentially rather than assumed and then asserted as fact in the HLD draft decision paper.

**Forward Market Liquidity**

Energia welcome the recognition by the SEM Committee of the issue of forward market liquidity in the I-SEM. However the proposed decision for trading energy represents a missed opportunity to improve competitive dynamics in the forward market and a greater reliance on regulatory measures to promote forward market liquidity. Forward contracting will commence up to 24 months in advance of the start of the I-SEM, with some retail customers wishing to contract 3 years ahead. It is therefore important that forward market liquidity is prioritised in the detailed design phase of I-SEM to avoid any potential negative effects on the already low levels of liquidity in the forward market leading up to the start of the new market. Such a scenario would be to the detriment of I-SEM consumers. Rigorous testing of Euphemia will aid this process.

**Scheduling Risk**

Scheduling risk under the proposed market design is an indicator of the efficiency of the DAM. As discussed in section 5.1 and confirmed by Baringa, scheduling risk is likely to increase under the HLD. As evidenced by Baringa and NERA, increased scheduling risk for generators will lead to higher costs for consumers through inefficient DAM schedules and prices. It will also undermine liquidity in the forward market, negatively effecting retail competition, and increasing risk premiums on forward contracts.

**Non-Mandatory DAM Participation**

Non-mandatory participation in the DAM will increase scheduling risk and split liquidity in the DAM. This could have a significant negative impact on forward market liquidity in the absence of physical forward trading and self-scheduling, undermining retail competition. Therefore Energia would stress that any move towards a non-mandatory DAM under the proposed HLD necessitates the introduction of a physical contract market and self-scheduling to mitigate against this risk.

**Market Power in the I-SEM Energy Market**

Energia is concerned that the information asymmetry due to the dominant position of ESB will result in inequitable access to market in the HLD. In particular, the requirement for generators to internalise their start up and no load costs and risks of scheduling and commitment mean that portfolio players will have an inherent advantage given the increased market information they hold when formulating bidding strategies, particularly in the DAM. This will have detrimental effects on the conditions for effective competition in the generation sector resulting in long-term

[7] Cross reference paragraph 6.4.32 on P.45 of the Draft Decision Paper.

negative effects for consumers. ESB will also accrue significant portfolio benefits in terms of minimising downside scheduling risk and influencing DAM outcomes as described in the Baringa report.

In the interests of competition therefore we reiterate our view that forward physical contracting and self-scheduling (which could be incorporated as a variation of Option 3) would provide effective market led mitigation against the exertion of market power in forward and DAM timeframes and strongly suggest that this is reconsidered as an adaptation to the proposed HLD.

In the absence of physical forward contracting and self-scheduling it would seem prudent to either re-introduce ring fencing across ESB's generation assets or significantly increase the level of directed forward contracts (or similar regulated forward contracts). The SEM Committee should note that ring fencing was removed because of the protection offered to the consumer through the BCoP.

Given the weakening of the BCoP and the potential reinforcing of ESB dominance within the HLD (ESB will own and operate the only extensive generation portfolio in the I-SEM and therefore will disproportionally accrue the significant portfolio benefits identified in this report), as noted by CEPA in their 2010 report the reintroducing effective ring fencing would improve the structural basis for competition in forward and spot timeframes. In the absence of the reintroduction of ring fencing a significant increase in directed contract volumes (or similar regulated forward contracts) is required to mitigate the incentives to exert market power in both forward and DAM timeframes. We also strongly recommend the implementation of the market power mitigation measures suggested for Option 3 in section 4.2.3.6 of our response to the SEM-14-008.

**Aggregator of Last Resort**

We would stress the need for market participants to be able to compete economically against Eirgrid to deliver an aggregation service for renewable generators. Given the potential for Eirgrid to monopolise the delivery of this service careful consideration needs to be given to the set-up of the aggregator of last resort in the I-SEM to ensure there is sufficient scope for effective competition to emerge for the delivery of this service, reducing costs and maximise benefits for renewable generation.

**Credit and Working Capital Requirements**

Energia would strongly emphasise that increases in credit or working capital requirements are a significant burden on market participants and act as a barrier to new entry, discourage effective competition (both in terms of new entry and discouraging existing supply companies from growing their market share) and therefore increase costs for I-SEM consumers. It is therefore essential that the I-SEM market design focuses on minimising these costs for both the capacity and energy markets (across all timeframes).

Energia would also emphasise that imposing onerous credit requirements for forward contracting could be used by a dominant entity to choke off retail competition in the I-

SEM and recommend that the SEM Committee ensure that the credit requirements imposed by ESB on counterparties when contracting in the I-SEM regulated and unregulated forward markets are evidenced to be proportionate to the commercial risks.

**Market Power in the I-SEM Capacity Market**

Energia welcomes the recognition by the SEM Committee of the issue of market power in the capacity market and we would emphasise that it is important to acknowledge the potential for predatory pricing and non-commercial objectives given the dominant position of ESB. Energia therefore strongly advises against the implementation of a quantity based mechanism as the level of competition in the I-SEM capacity market is not be sufficient to support an efficient market based valuation of capacity without extensive regulatory intervention. Furthermore, we recommend that careful consideration is given to the market power mitigation measures required under a quantity based mechanism and request that the SEM Committee rigorously assess the feasibility of implementing these effectively.

**Need for a Long-Term Price Based Mechanism**

A long-term price based mechanism (with a sloping demand curve similar to the current SEM mechanism) remains the most appropriate form of capacity mechanism for the I-SEM. Compared to a quantity based scheme, within the context of I-SEM, a long-term price based CRM will:

1. Reduce the risk of predatory or non-commercial pricing in the I-SEM capacity market;
2. Reduce volatility in the I-SEM capacity price;
3. Reduce regulatory risk;
4. Avoid inappropriate plant exit and entry cycles; and
5. Deliver cheaper security of supply for I-SEM consumers over the long-term.

As NERA note that the SEM Committee decision to implement a quantity based mechanism has been biased by a mischaracterisation of the typical attributes of price based mechanisms (such as an assumption that they cannot provide appropriate exit signals) and an incorrect understanding of the risk of double payments (the Double Payment Fallacy). This has resulted in not enough attention being paid to fundamental aspects of the I-SEM market (such as its small size and the dominance of ESB) and the concerns these create regarding the potential abuse of market power, capacity price volatility and the establishment of an inappropriate cycle of entry and exit; all of which are to the detriment of security of supply and the I-SEM consumer. We also note the increased regulatory risk introduced by the long lead times of a quantity based mechanism. If a quantity based mechanism had been in place in the current SEM generators could not have anticipated arbitrary regulatory decision such as those taken on gas capacity bidding or the carbon levy.

**Fundamental Issues with Reliability Options in I-SEM**

Contrary to the claims made in the DDP and IIA, reliability options do not represent best international practice. The experience to date of Reliability Options in markets such as Columbia and New England demonstrate this. Furthermore, Energia would strongly emphasise that reliability options are not an appropriate CRM for the I-SEM for the following reasons:

1. They introduce further significant needless complexity into the HLD (including into the energy forward market);
2. They impose significant and unnecessary risk (including increased regulatory risk and amplified exposure to scheduling risk) onto generators that will translate into higher costs for consumers;
3. They unnecessarily conflate and exacerbate market power concerns in both the capacity market and energy market (as the RO penalty regime is linked to the energy market price);
4. They raise significant issues for the efficient functioning of the I-SEM regardless of the reference price that is chosen (discussed in detail in section 6.3.2 of this report);
5. They effectively exclude any payment of “missing money” to renewable generation due to their penalty regime being linked to payments in the energy market; and
6. They require a link to physical capacity to solve the “missing money” problem thereby making them subject to many of the issues identified with other forms of CRM (discussed in detail in section 6.3.1 of this report).

Therefore implementing reliability options will have negative impacts on investment and security of supply and will result, over the long term (the appropriate time horizon to consider a capacity mechanism) in additional costs to I-SEM consumers.

Therefore, if the SEM Committee (despite the strong arguments set out in section 6.2 and 6.3 of this report) proceeds with implementing a quantity based CRM, Energia strongly recommend that they implement a mechanism that is closely aligned to the GB capacity mechanism. This will:

1. Reduce superfluous complexity;
2. Minimise unnecessary risks of CRM participation for generators, decreasing costs for consumers;
3. More easily facilitate participation by small generators, DSUs and AGUs improving competition and promoting demand side participation in the I-SEM; and
4. More easily facilitate participation of wind, assisting delivery of renewable targets.

**Transitional Arrangements for Capacity Remuneration**

Energia would emphasise the need for transitionary arrangements in the I-SEM if the SEM Committee proceeds with a quantity based mechanism. Proceeding with a quantity based mechanism without allowing generators to acquire sufficient operational experience of new market arrangements is likely to result in inefficient capacity pricing and therefore additional costs for consumers. Energia therefore strongly advises the SEM Committee to maintain the current SEM capacity mechanism for an appropriate transitional period taking into account the auction lead time and a 'bedding in' period for the I-SEM energy trading arrangements and the new DS3 system services regime. Compressing the timescale between the auction and the start of initial I-SEM capacity products under a quantity based mechanism would result in the inefficient valuation of capacity; exclude new entrants from participating; and require a full set of auction rules and market power mitigation measures to be in place by the end of 2015 which is completely unrealistic.

**Unnecessary Complexity and Risks in the Choice of HLD**

Energia would stress the unnecessary complexity of the HLD and the barriers this will place upon new entry and external investment; particularly in a small market such as the I-SEM. The SEM Committee should also note that any additional risks they place on generators will manifest themselves as additional costs to I-SEM consumers in the long term either through reduced efficiency of the All-Island market or inappropriate generator exit.

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# Contents

# 2 Introduction

Energia welcomes the opportunity to respond, with evidence, to the SEM Committee's draft decision and initial impact assessment on the I-SEM High Level Design (SEM-14-045 and SEM-14-046 respectively). The structure of our response is as follows.

Section 3 summarises key findings from the NERA report commissioned by Viridian to look at the soundness of the draft HLD decision and the robustness of the Initial Impact Assessment supporting it. The NERA report identifies "many problems in the quality of the appraisal used to justify the SEM Committee choice of Option 3 and Reliability Options and concludes that the SEM Committee's decision is unsound and that market participants cannot have confidence that the SEM Committee has reached the right decision on high level design for the I-SEM". Based on these findings we call for a critical review of the final impact assessment and associated recommendations to the SEM Committee by a third party to inform the HLD decision and emphasise the need for a third party 'quality assurance' role in the I-SEM project going forward. In this section we also highlight the main findings of a multi-client Baringa report on the potential for increased scheduling risk under the proposed energy trading arrangements and its potential implications for I-SEM. We also comment in this section on the need for clear and achievable project timelines, recognising the importance and magnitude of the work that remains to be done, and the significant delays to the original timetable already experienced.

In section 4 we comment on the change of direction in regulatory approach from current market arrangements which is apparent in the draft decision. Having made this observation we stress the importance of appropriate clearly spelt out regulatory mechanisms to deal with the complications and distortions that the all-island market presents. This market (both in respect of energy trading and capacity remuneration) cannot be relied upon to work efficiently and competitively in the absence of clearly specified regulatory management, irrespective of developments at a European level in terms of financial regulations and market integration.

Section 5 discusses the proposed energy trading arrangements across all timeframes and highlights concerns regarding scheduling risk, forward market liquidity, market power and competition in the I-SEM energy market. Given the potential for increased scheduling risk under the proposed energy trading arrangements and the benefits (as well opportunities to exert market power) this provides the only large portfolio player, we strongly recommend, in the interests of long-term competition in the I-SEM, that further consideration be given to our proposal for a centrally traded self-scheduled market as set out in section 4.2.4 of our response to the HLD consultation SEM-14-008. In the absence of physical forward contracting and self-scheduling, combined with the weakening of BCoP, it would be necessary to either re-introduce ring fencing across ESB's generation assets or significantly increase the level of directed forward contracts (or the equivalent). In addition, we strongly recommend that further consideration be given to the market power mitigation measures we suggested for Option 3 in section 4.2.3.6 of our response to the SEM-14-008.

Section 6 concentrates on the proposed capacity remuneration mechanism (reliability options) and stresses the concerns we have in relation to this in the context of state-owned dominance, the small size of the all-island market and significant adverse impacts on liquidity. Given the serious and complex issues that will have to be resolved for any form of quantity based mechanism to work in the all-island context we strongly maintain that serious consideration be given to retaining the current CPM with minimal changes required. We emphasise the need for transitional capacity arrangements in the I-SEM if the SEM Committee proceeds with a quantity based mechanism and any so-called quantity based mechanism must be carefully tailored to suit all-island market conditions.

Section 7 concludes with our key messages and Annex 1 lists the independent expert reports from NERA and Baringa that support this response.

# 3 Expert Third Party Assessment

Viridian commissioned NERA to carry out an evaluation of the HLD Draft Decision and Initial Impact Assessment. ***Viridian would strongly emphasise that the findings of the report are independent and represent the considered views of experts in the field of electricity market design.*** NERA would be willing to discuss their report with the RAs or government departments if that would be helpful, and we would be willing to exclude ourselves from such discussions.

Viridian also participated in a multi-client report written by Baringa looking at the potential impact of increased scheduling risk for the I-SEM under the proposed electricity trading arrangements. The other companies that participated in the report were Tynagh Energy Limited, AES and Bord Gais Energy.

## 3.1 *NERA Evaluation of HLD Draft Decision and Initial Impact Assessment*

The main findings of the NERA report are summarised below.

### 3.1.1 Inadequately Defined and Subjectively Applied Assessment Criteria

"… [T]he appraisal criteria used in the IIA and reflected in the DDP are defined in terms that can only be evaluated subjectively. The IIA then applies them selectively, or in conjunctions with further unstated criteria, so that the market designs are not appraised on a level playing field. The result is that the SEM Committee's appraisal method gives every appearance of being biased in favour of a prior decision to select Option 3 and Reliability Options."[8]

To the extent that the assessment criteria used by the SEM Committee are ambiguously defined and applied inconsistently in the formal appraisal of energy trading and CRM options, the HLD decision is not evidentially based. This is because the HLD options are not assessed against a consistent set of criteria that are rigorously defined and applied. Therefore the evaluation cannot be considered as objectively grounded.

### 3.1.2 Vague Descriptions of HLD Options

With regards to the description of the energy trading options and CRM designs NERA comment as follows:

"… [T]he various possible designs for energy trading arrangements ("Options") and CRMs are not completely specified, or else different designs are specified in terms that overlap and prevent proper comparisons…"[9]

"These incomplete or variable definitions of different designs make it difficult to distinguish between the merits of different schemes. They also allow those carrying out the appraisal to pick and choose what (positive and/or negative) characteristics to

[8] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 10 on p.3
[9] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 8 on p.2

assign to each market design. The result is a highly subjective and prejudicial review of each of the designs, which appears to be aimed at justifying the selection of Option 3 and Reliability Options, instead of at identifying the market design best suited to the I-SEM."[10]

To the extent that the energy trading options and CRM options are inadequately described it prevents a proper, objective evaluation of them and the supporting evidence. This further undermines the robustness of the HLD consultation process and therefore the SEM Committee decision. We note that many of the questions Energia submitted to the RAs in January 2014 remain unanswered despite being fundamental to an understanding of the intent of the HLD energy trading options and the proposed means for the market design to deliver upon that intent.

### 3.1.3 Lack of Robust Argumentation

With regards to the quality of argumentation in the DDP and IIA NERA comment as follows:

"The arguments set out in the IIA are of very poor quality and do not support the decision process set out in the DDP. The descriptions of market designs are incomplete and not completely fixed or distinct, the appraisal is highly selective and subjective, and incorrect arguments are asserted without the support of observation or analysis."[11]

Due to the lack of robust argumentation ("some of the arguments in the IIA and DDP are …"[12] described by NERA as "… demonstrably incorrect or non-sequiturs"[13]) NERA conclude that

"… [N]o-one can have any confidence that the SEM Committee has reached the right decision on [the] high level design for the I-SEM."[14]

### 3.1.4 Inadequate consideration of the effect on competition of the HLD

In light of the known structural issues relating to ESB dominance in the generation sector of I-SEM, NERA strongly criticise the lack of detailed consideration by the SEM Committee of how market power will be managed under the proposed energy trading arrangements and CRM design, and state the requirement for robust market power mitigation measures (such as increased directed contract volumes if the current SEM BCoP is abandoned (or diluted) under the proposed HLD). As they observe:

"Nothing suggests that market power problems have been eliminated since 2007, or will be eliminated in the near future. However, according to the RAs, it will be safe to

[10] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 9 on p.2
[11] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 16 on p.4
[12] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 11 on p.3
[13] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 11 on p.3
[14] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 17 on p.4

abandon the current BCOP, despite not knowing what will replace it under Option 3. We conclude that the SEM Committee's willingness to abandon the BCOP represents a subjective leap of faith, or a prejudicial bias in favour of Option 3, rather than a conclusion based on evidence, and that the SEM Committee should consider what alternative measures or expanded measures (such as a greater volume of directed contracts) would be made necessary by the adoption of Option 3.

Measures to mitigate market power are also likely to be necessary in any centralised auction of capacity market instruments in the I-SEM. The SEM Committee recognises this need in the IIA, but ignores it in the DDP, frequently describing Reliability Options as "market-based", whilst highlighting the degree of regulatory intervention in other CRMs. This selectivity in describing the impact of market power mitigation has biased the SEM Committee's evaluation of CRMs for the I-SEM. As a result, we conclude that the SEM Committee has no reliable basis for assessing CRMs, or for selecting Reliability Options, with regard to their impact on competition."[15]

### 3.1.5 Selection of Proposed Energy Trading Arrangements for I-SEM is Unsound

NERA is extremely critical of the regulatory process followed by the SEM Committee in selecting the proposed energy trading option for the I-SEM. Their conclusions on this matter are quoted in full.

"The "Qualitative Appraisal" set out in the IIA provides no objective or balanced support for the SEM Committee's draft decision.

There are gaps in the definition of the chosen Option and its potential effects that are significant enough to have affected the SEM Committee's appraisals. More analysis would be required to ensure that the chosen Option meets practical and objective criteria of efficient market design. In the meantime, the SEM Committee's appraisal is selective and prejudiced, rendering its decision unreliable.

Euphemia is not guaranteed to produce an efficient pattern of output in the day-ahead market, but the SEM Committee assumes that it will. In fact, given the lack of detail on intra-day and real-time institutions, any of the proposed high-level market designs has the potential to produce inefficient outcomes. Without a proper assessment of this potential inefficiency, the SEM Committee has no sound analytical or evidential basis for its decision.

The SEM Committee has not addressed the problem of volume/scheduling risk. A full assessment of the options would have considered this problem in detail, taking into account a detailed description of the arrangements for scheduling and despatch. The DDP and IIA are missing any description of these arrangements and fail to consider the associated risks to market participants. The appraisal of the proposed Options is therefore incomplete and necessarily subjective.

[15] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 221 and 222 on p.50

Errors in the discussion of cross-border flows, and a failure to consider fully the alternative contract forms, effectively render invalid the conclusions reached in the DDP about the use of interconnectors.

In relation to the liquidity of forward markets, the assessment fails to compare the Options on a level playing field. As a result, the conclusions reached in the DDP must be considered unsound.

We conclude:

- that the SEM Committee's description of the Options is incomplete and in some cases erroneous;
- that SEM Committee's appraisal of the Options is selective, subjective and prejudiced; and
- that the SEM Committee's draft decision is not soundly based on evidence or analysis."[16]

### 3.1.6 Selection of Proposed CRM for I-SEM is Unsound

NERA is extremely critical of the regulatory process followed by the SEM Committee in selecting the proposed CRM for the I-SEM. Their conclusions on this matter are quoted in full.

"… [T]he SEM Committee has not justified its proposed decision to select Reliability Options because:

- the SEM Committee has left out significant details from the proposed design of the RO, even though those details are crucial to achieving the RO's intended purpose, so that its evaluation of the RO is *incomplete*;
- the SEM Committee has taken a *selective* approach to describing the effects of each design, specifically by overlooking possible adverse effects of the proposed RO; and
- the SEM Committee has evaluated possible designs for a CRM against criteria that vary from case to case, in scope and in definition, introducing a *bias* into the appraisal and preventing a fair, like-for-like evaluation of the designs.

Because of these flaws in the appraisal of the various CRMs, the SEM Committee's choice is not soundly based. "[17]

### 3.1.7 Risk of legal challenge

NERA observe that the standards exhibited in the I-SEM HLD decision making process are so poor that it could expose the SEM Committee to the risk of legal challenge regarding the HLD decision in the future.

[16] "I-SEM Draft Decision SEM-14-045: A Review" paragraphs 119 to 125 on p.27
[17] "I-SEM Draft Decision SEM-14-045: A Review" paragraphs 193 and 194 on p.43

"We found areas where the appraisal is subjective, selective and biased, with the effect that the discussions are prejudicial and do not provide a proper basis for selecting an electricity market design, putting the Decision at risk of legal challenge."[18]

### 3.1.8 Need to re-evaluate the proposed I-SEM HLD decision

NERA emphasise the need to re-evaluate the HLD decision before a final decision is made. They set out the minimum criteria required for this assessment in paragraph 13 on p.3 of their report and advise that:

"… [T]he SEM Committee would have to meet all these requirements by the time of a final decision. We are conscious of the deadline for this decision, and our comments below are intended to fit with the proposed decision process. Should it not prove possible to resolve the outstanding difficulties in time, the SEM Committee would have either to postpone the final decision, or else to recognise that its decision is not robust and cannot be binding on the precise form of the I-SEM. Instead, its final decision would only be able to (1) recommend a market design as a starting point for further investigation, (2) list the matters to be investigated in detail, and (3) define the criteria for changing or adjusting the market design in the light of these investigations."[19]

### 3.1.9 Need for robust Quality Assurance processes

NERA stress the need for a robust Quality Assurance process moving forward to avoid the plethora of issues identified in relation to the HLD decision process from recurring. They advise that:

"… the SEM Committee would need to adopt (and publicise) a procedure that allowed third parties to submit technical advice and to scrutinise all the work on a detailed design. The impact of market arrangements depends crucially on the details of their design and such scrutiny will be important to ensuring an efficient design for the SEM. The SEM Committee will in any case need to set up a procedure whereby the market designers and/or third parties can refer for adjudication (1) decisions to change (or not to change) the market design and (2) disputes over the detailed specification."[20]

NERA also stress that if the SEM Committee proceed with the HLD based on their current description and evaluation that significant work is required in the detail design. Furthermore, they emphasise the need for the RAs to engage more than one expert advisor.

[18] "I-SEM Draft Decision SEM-14-045: A Review" in Conclusions section of the Executive Summary on p.iii
[19] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 14 on p.4
[20] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 15 on p.4

"… resolving … outstanding questions will require significant work during detail design phase. Experience to date suggests that this task cannot be awarded to an individual advisor … ."[21]

## 3.2 Baringa Report on Scheduling Risk and its Implications for the I-SEM HLD

The main findings of the Baringa report are summarised below.

### 3.2.1 Potential limitation on use of linked block orders

Paragraphs 1.5.9 and 1.5.10 of Annex B of the DDP suggest that generators can utilise linked block orders to manage their commercial and technical risks in Euphemia. Baringa note, however, that the use of linked block orders has been restricted in other jurisdictions to avoid potential issues with Euphemia.

"…many power exchanges have placed limitations on the number and size of block orders and other complex bidding formats that participants can submit in the DAM for consideration by EUPHEMIA. These limitations can help ensure the market clearing algorithm reaches a timely and feasible solution. … The proposed HLD for I-SEM does not specify what limitations, if any, are likely to be placed on the use of complex order formats by I-SEM participants."[22]

### 3.2.2 I-SEM order formats may be subject to EUPHEMIA governance arrangements

Baringa note that the SEM Committee may not have a unilateral choice regarding the Euphemia order formats that are available to I-SEM generators and observe that this decision may be subject to Euphemia governance arrangements.

""It is … worth noting that the offer formats available to market participants may not be decided unilaterally by the RAs but through the EUPHEMIA governance arrangements."[23]

Furthermore, they observe that:

"Relative to the proposed I-SEM design, the requirements for sophisticated offer formats are less in other European markets given their larger size and more diverse and flexible generation mixes, and the fact that EUPHEMIA is not used as an exclusive route for creating the market schedule."[24]

### 3.2.3 Choice between volume and price risk

Baringa explain in relation to linked block orders how the proposed HLD forces a generator to choose between exposure to volume risk or price risk. It should be

[21] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 42 on p.10
[22] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.12
[23] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.9
[24] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.9

noted that this choice itself determines the type of EUPHEMIA order formats used by the generator and therefore is not exclusive to linked block orders.

"… [T]he offer strategy for a single asset using Linked Block Orders will face choices about how to spread start-up and no load costs across the parent and child block prices. Loading the full possible start-up cost and no-load cost into the parent block increases the risk that the parent will be out-of-the-money, although these losses may be offset by positive margins on child blocks in determining the final clearing outcome. On the other hand, spreading no-load or start costs across child blocks increases the competitiveness of the parent block, but at the risk of cost under-recovery if child blocks are not cleared with the parent. The examples … demonstrated how sensitive offer acceptance could be. Taken together with the potential for paradoxically rejected bids this highlights the potential for significant scheduling risk associated with judgements around offer parameter choices."[25]

### 3.2.4 Inability for generators to mitigate all risks

Baringa observe that even if there are no restrictions imposed upon the use of Euphemia order formats, given the requirement for generators to choose between volume risk and price risk, it will not be possible for them to adequately manage all their commercial and technical risks under the proposed design.

"Given that participants will have to choose between the use of offering a set of alternative profiles, versus using a parent-child structure, this implies that they will need to weigh up the uncertainties associated with the within-day shape of prices against the uncertainties associated with accepted volume and duration (and corresponding risk of under-recovery). For example, on a day with significant uncertainty as to wind generation, and hence to the profile of net demand, the participant might choose to utilise a set of profiles to have alternative blocks covering different potential peak periods, rather than offering a parent that might turn out to have been set at a period of low net-demand. This suggests that additional information will be important, particularly in regard to wind and demand forecasts."[26]

### 3.2.5 Sources of scheduling risk under I-SEM proposed design

Baringa explain the source of scheduling risk in the EUPHEMIA algorithm as follows:

"… scheduling risk is unlikely to be eliminated under the new market design since dispatch still relies on the outcomes from a central algorithm (in this case EUPHEMIA) which market participants may not be able to anticipate reliably, particularly in the absence of a Bidding Code of Practice. EUPHEMIA supports complex and sophisticated offer formats to help participants manage their technical and commercial constraints within the day-ahead scheduling process. However, with the exception of the possible partial acceptance on profile offers, complex or sophisticated orders can normally only be executed fully or rejected fully, and this

[25] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.28
[26] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.28

constraint can lead to EUPHEMIA rejecting some complex orders even if they are priced below the outturn market prices. Rejected orders that are apparently in-the-money at outturn prices are termed 'paradoxically rejected orders' in the EUPEHMIA literature."[27]

We refer to this source of scheduling risk as System Scheduling Risk in section 5.1 of this report. They also identify a second source of scheduling risk that we refer to as Dynamic Scheduling Risk throughout this report. They explain this second source below:

"In developing an offer strategy, a generator will need to take into consideration the potential strategies that could be followed by competing generators. The issues outlined above are likely to drive diversity in strategies, and these are likely to evolve in a dynamic way in response to analysis of market outcomes [including forecasts of wind participation and demand in the DAM] (assuming that such strategies are relatively unconstrained by bidding principles). It is likely that market participants with sufficient resources will aim to model the EUPHEMIA algorithm to enable them to test and develop the sophistication of their strategies. So the scheduling risk inherent in the limitations in EUPHEMIA offer structures will be magnified by the uncertainty and potential instability in strategies applied by different competitors. This is compounded at times when GB and SEM price levels are similar as generators will then need to consider both SEM participant strategies and the potential level and shape of GB offers. Whilst it is difficult without conducting detailed modelling to compare the scheduling risk under current SEM arrangements (associated with the Uplift methodology) and under the proposed I-SEM arrangements, it could be that this "competitive strategy dynamic" leads to a higher degree of scheduling risk. …"[28]

The combination of factors that lead to scheduling risk under the proposed design and covered in section 3.2.4 and in the current section, are summarised by Baringa as follows:

"Under a centralised market,[such as the proposed I-SEM design,] the hedging task for a mid-merit plant becomes more complex since it will be dispatched based on the outcome of the market algorithm. At the day-ahead stage there will be considerable uncertainty regarding market conditions, particularly with respect to wind output, and the potential bidding strategies of competitors. In the absence of a Bidding Code of Practice it will be significantly more difficult than under the current SEM to anticipate the offers of competitors, which will increase scheduling risk. A key challenge for generators will be how to internalise start costs and no load costs into offers when there is a high degree of uncertainty regarding the fixed output that these costs can be spread over without increasing risk of exclusion from the DAM schedule. Generators also face the additional problem of how to construct commercial offers that ensure the DAM schedule they receive respects the dynamic technical

[27] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.8
[28] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper",p29

constraints of their unit(s). It is therefore possible under the proposed design that a generator, bidding at cost, will not be scheduled, even if the DAM price is higher. In this scenario a generator that had hedged forward would be exposed to the market price, at a loss relative to its SRMC. This is scheduling risk."[29]

### 3.2.6 Exposure to scheduling risk is amplified by choice of CRM

Baringa note that a generator's financial exposure to scheduling risk in the I-SEM is significantly amplified by the SEM Committee's choice of Reliability Options as the form of CRM. As they observe:

"Exposure to scheduling risk under the I-SEM is compounded by the proposed design of the Capacity Remuneration Mechanism which will be based on financial Reliability Options that are likely to be settled against the DAM price. It is possible under the design that a generator will be exposed to payments under the Reliability Options but not being scheduled."[30]

### 3.2.7 Risk of price volatility and inefficient outcomes

Baringa note that strategies to model the commercial dynamics and technical constraints of generators and to avoid scheduling risk could result in inefficient market outcomes and inefficient volatility under the proposed HLD.

"… [T]here is a concern that the consequence of strategies designed to mitigate scheduling risk, when translated across the market, could lead to inefficient outcomes. For example, if a material number of mid-merit plant were to zero-bid, this could exacerbate an issue that will face the market anyway as wind deployment increases, potentially leading to spuriously low prices at times, possibly combined with spikes as more peaking plant are required to create required shape. Such inefficient volatility is likely to deter forward trading and new investment, to the extent that prices are in part an outcome of the specifics of EUPHEMIA and associated strategies, rather than fundamental costs. In a similar manner, interconnector flows could be distorted in an inefficient manner."[31]

### 3.2.8 Implications of scheduing risk for I-SEM forward market

Baringa observe that scheduling risk may lead to higher risk premiums being applied to generators on forward contracts. Energia note that there is substantial evidence of this within the current SEM forward contract market – see section 5.2 of this report. This would increase costs to the consumer under the proposed market design. As Baringa comment:

"Managing the scheduling risk associated with this dynamic spot market position will introduce additional complexity for independent generators compared to the current

[29] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.6
[30] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p. 8
[31] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.30

SEM arrangements, and may lead to participants seeking a higher risk premium on forward contracts."[32]

They also note that the presence of Scheduling Risk in the I-SEM, and the complexity in offer strategies and the potential inefficiencies in DAM outcomes it generates, could undermine liquidity in forward markets putting a key policy objective[33] of the SEM Committee at risk.

"Given that the primary requirement for a liquid forward market is full confidence that the day-ahead index is reflective of supply/demand fundamentals, transparently derived, and free from potential distortion associated with particular participant strategies, we believe that the set of issues outlined in this document warrants careful consideration if this key objective of the new arrangements is to be met."[34]

### 3.2.9 Proposed design unduly benefits large portfolio players (e.g. ESB)

Baringa emphasise the ability of large generation portfolios (in the context of the I-SEM this refers to ESB) to diversify scheduling risk through the implementation of portfolio strategies and highlight concerns regarding information asymmetry in the I-SEM within the context of a weakened BCoP.

"… having a portfolio position is nevertheless likely to bring benefits. A portfolio player knows what the rest of its portfolio is doing with regards to commercial offers. In the context of the proposed High Level Design this provides an information advantage over a stand-alone generator who needs to guess this information to determine its most effective strategy. The advantage increases with the size of portfolio. In the current SEM this information asymmetry is managed through the Bidding Code of Practice which guarantees generators can compete on equal terms. However, without bidding principles it is very difficult to estimate the offer prices of competitors. Furthermore, it is not clear how unit-based bidding would in practice be interpreted where offers can be 'co-ordinated' across a portfolio. For example, with a hypothetical portfolio of three mid-merit plant, a strategy might involve zero-bidding for some volume of generation whilst offering capacity from other similar assets through parent/child offers placed at different times of the day."[35]

Baringa also observe that the benefits to large portfolio players (such as ESB) potentially extend to the balancing market timeframe.

" … the High Level Design proposal for a single price cash-out means that longs and shorts in a generation portfolio will effectively net out. While unit bidding is proposed for the DAM and IDM, cash-out will be at a portfolio level. This would potentially advantage portfolio players and reduce within day liquidity, although other aspects of

[32] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.25
[33] Cross reference paragraph 6.4.6 in the DDP.
[34] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.32
[35] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.29-30

the detailed design may constrain participant behaviour from benefitting from this apparent anomaly."[36]

### 3.2.10 Proposed design makes effective market power mitigation difficult

Baringa note that the complexity of the trading arrangements will lead to the formulation of sophisticated offer strategies. Furthermore, they observe that it will be difficult for regulators to determine if such strategies are anti-competitive or an abuse of market power.

"…[T]hose players with a portfolio of assets are likely to be able to develop more sophisticated strategies over time, given the complex nature of the DAM in terms of offer structures and price setting. This may be especially true in a small market such as the I-SEM, where single plants represent a material share of the stack. It is likely that these players will aim to replicate the EUPHEMIA algorithm to develop and test these strategies, and assess the potential portfolio benefits in terms of an increased level of infra-marginal rent. It may prove very difficult from a regulatory perspective to distinguish between valid commercial strategies and strategies that are potentially anti-competitive or abuse a position of market power at certain times."[37]

## 3.3 *Next Steps in the Process*

The final HLD decision will have long lived consequences for the consumer well into the next decade and any inefficiency, risks or poor specification inherent in the market design will raises costs and prices of electricity and leave consumers exposed to the risk of under-investment in capacity. Given these long term implications it would be undesirable to proceed with a final HLD decision without robust evidential support for it having considered all its real world effects relative to viable alternatives.

Fundamental concerns and question emerge about the proposed HLD from the expert third party assessments summarised briefly above and appended to this response as evidence. This combined with the magnitude of critically important issues reserved for the detailed design phase calls for a review of the timetable and process for delivery of I-SEM. For example the high level proposal for Reliability Options (ROs) needs arrangements linking them to the physical delivery of capacity to ensure that ROs solve the missing money problem. More generally the CRM design must be carefully tailored to suit all-island market conditions and, if auction based, will require appropriate lead times, with transitional arrangements. Equally important for the detailed design phase are effective measures to promote liquidity in the forward timeframe, the development of an appropriate market power mitigation strategy and the development of real time arrangements for energy trading.

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[36] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.30
[37] "Scheduling Risk under the proposed I-SEM High Level Design: An Issues Paper", p.30

These are fundamentally important issues and resolving them is not a trivial exercise that can be accelerated. According to the project plan published in February 2013, the detailed design is to be completed by February 2015. Given the delays that have been experienced to date the project is about 5 months behind schedule and thus without amendment the detailed design phase will be compressed by a factor of two, optimistically assuming it can commence in September 2014. In light of this, Energia would urge the SEM Committee to carefully review the original timetable for the I-SEM project as published in February 2013 and consider the continued feasibility of this given the delays that have been experienced to date and the magnitude and nature of the work and testing that remains to be completed. An extended timetable is necessary[38] and it would be advisable to reach such a determination at this stage of the process to facilitate a more considered and consultative detailed design phase. It is essential that an updated project plan is published as the earliest convenience allocating sufficient time for:

- Robust and inclusive EUPHEMIA testing before a final HLD decision
- Genuine industry consultation in detailed design
- Participant IT procurement and readiness

[38] If previous project plant was realistic, the new plan must change the implementation date by 5 months.

# 4 Undesirable Shift in Regulatory Approach

This brief section comments on the change of direction in regulatory approach from current market arrangements which is apparent in the draft decision. Having made this observation we stress the importance of adequate, robust and clearly set out regulatory mechanisms to deal with the complications and distortions that the all-island market presents. This market (both in respect of energy trading and capacity remuneration) cannot be relied upon to work efficiently and competitively in the absence of well specified regulatory management, irrespective of developments or perceived requirements at a European level.

## 4.1 *From Regulation to Laissez Faire*

The proposed I-SEM design (in terms of its energy trading arrangements and capacity remuneration mechanism) represents a regulatory U-turn in relation to fundamental consumer concerns pertaining to the All-Island market – e.g. promotion of competition and market power mitigation. Energia notes, however, that the underlying market conditions have not materially changed since 2007. The I-SEM will remain a small market characterised by the dominance of ESB (state owned company) in generation and supply. This cannot be dismissed with vague references to enhanced interconnection and market integration, as validated by CEPA as recently as 2010[39] and accepted by the SEM Committee in 2012 in their decision on ESB horizontal reintegration[40], and which is further explained and reinforced by NERA in their report submitted with this response.

It is clearly evident, from review of the draft decision and initial impact assessment, that misguided assumptions regarding compliance with European energy policy and a desire for so called ‘market based’ solutions are key drivers of this shift in regulatory approach. It should be noted, however, that market based solutions only work in competitive markets (which I-SEM is clearly not) and that a fully competitive market – i.e. a market that needs no regulatory intervention - is an idealised concept rather than a reality. This is borne out in the NERA report.

## 4.2 *Target Model Compliance*

With respect to compliance with the European Target Model, the I-SEM selection process and design, according to NERA, betrays an unfortunate misunderstanding of efficient interconnector flows with its focus on day ahead trading of electricity as opposed to efficiently pricing the underlying commodity and minimising competitive distortions. Scheduling the I-SEM through EUPHEMIA is not a requirement of the EU Target Model nor does it guarantee an efficient day-ahead market outcome or efficient market coupling. It therefore seems imprudent for the SEM Committee to adopt such an unnecessary and extreme position in relation to the implementation of the EU Target Model without first conducting rigorous testing to ensure the proposed

[39] CEPA (2010), ‘Market Power and Liquidity in SEM: a report for the CER and the Utility Regulator’, Cambridge Economic Policy Associates, 15 December 2010.

[40] SEM Committee (2012a), ‘SEM Market Power & Liquidity, A SEM Committee Decision Paper, SEM-12-002, 1 February 2012.

design (which would be unique within Europe) is in the long-term interests of I-SEM consumers.

## 4.3 State Aid Guidelines

EC State Aid guidelines stipulate that a CRM can only be justified when demonstrable *market failures* give rise to a generation adequacy problem. The market failures which give rise to this need in I-SEM have been demonstrated.

In explaining the rationale for choice of CRM in I-SEM the draft decision refers to the fact that "the EC and ACER have written on different CRM designs". These documents appear to be used as justification for the draft decision which is reflected in the positive decision weighting given to:

(1) Competitive, market-based solutions;

(2) Proportionality; and

(3) Minimisation of cross border trade distortions;

Reliance on (1) contradicts the basis for having a capacity mechanism in the first place and in reality there are no capacity mechanisms which rely on competitive, market based solutions including the RO type schemes preferred by the SEM Committee. The concept of (2) has little analytical value in choosing a capacity mechanism and (3) cannot easily be resolved by choice of capacity mechanism. These points are borne out in the NERA report.

## 4.4 Interconnection and Market Integration

The draft HLD decision points strongly to increased interconnection and enhanced market integration in a manner which gives the impression that these developments and ambitions will help resolve market power issues on the island of Ireland. For example, it states on page 20 that: "[i]nterconnection between the all-island market and the GB market has grown substantially since the start of the SEM" and page 21 states that "[i]ncreased interconnection with GB should permit greater price harmonisation between the two markets, insofar as the level of (and access to) interconnection allows".

However as recently as 2010 and 2012 CEPA and the SEM Committee accepted the need to retain the BCoP and directed contracts in order to mitigate market power. They reached this conclusion despite the entry of competing generators and the increase in interconnector capacity since 2007 as well as future interconnection. They noted that interconnector capacity was not a reliable rouse of competition because it would added to demand rather than supply, if it flowed from Ireland to Britain at peak times. The NERA report further comments that:

"[t]he SEM Committee cannot rely on interconnectors to be contributing to supply in peak periods, as they may be exporting to Britain at times of system stress. The risk that interconnectors make no contribution to security of supply at times of system stress is exacerbated by the strength of the penalties imposed at such times for not generating in the British market.[41]"

## 4.5 Conclusion

At the 17 June 2014 I-SEM workshop in Dundalk the regulatory authorities (RAs) introduced Dr Pablo Rodilla as an expert speaker to present his academic research on international experience with capacity mechanisms. He states in his research that "[t]he main aim of our work has been to highlight the fact that the final problem is not the market approach itself, but the lack of adequate regulatory mechanisms to deal with the complications that real life markets may present"[42]. This is good advice but that has been ignored in the I-SEM decision. Rather the proposed decision signals a desire on the part of the RAs to step away from the market and to rely on 'presumed' competition and liquidity for delivery of efficient outcomes. NERA has described this approach as "a subjective leap of faith"[43]. To the extent that the resulting market design favours ESB (a dominant state owned company) and provides a dividend to the Irish government, this offers no recompense to the NI consumer.

The market design chosen exasperates the ability for the only large portfolio player to exercise market power and to benefit from its portfolio position in both the energy and capacity market and this will only invite greater ad hoc regulatory intervention and oversight which creates uncertainty for market participants and introduces significant market inefficiencies.

[41] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 208 on p.47

[42] Batlle, C., Rodilla, P. (2010), "A critical assessment of the different approaches aimed to secure electricity generation supply", IIT Working Paper IIT-10-017A, July 2010 (version subsequently published in Energy Policy, vol. 38, iss. 11, pp. 7169-7179, November 2010).
Accepted for publication in Energy Policy

[43] NERA July 2014 report for Viridian, page 50

# 5 Energy Trading Arrangements

In this section we consider the proposed energy trading arrangements for I-SEM across each market timeframe. We also discuss the implications of scheduling risk within the context of the proposed HLD.

## 5.1 *Sources of Scheduling Risk*

There are two potential sources of scheduling risk that arise under the proposed energy trading arrangements. The first emanates from the design of the EUPHEMIA algorithm; the steps followed by the algorithm when maximising social welfare. For the purposes of this discussion this source of scheduling risk is referred to as System Scheduling Risk. The second source emanates from the requirement under the proposed energy trading arrangements for a generator to utilise EUPHEMIA offer formats to manage their commercial and technical risks. This latter source of scheduling risk is referred to as Dynamic Scheduling Risk because it arises from the accuracy of the information a generating company has regarding key parameters relevant to the formation of commercial offers for the DAM on any given day.

### 5.1.1 System Scheduling Risk

The potential for System Scheduling Risk in EUPHEMIA – i.e. the exclusion of “in the money” Block and MIC EUPHEMIA order formats – is discussed at length in section 4.2.3 of our original response to the HLD consultation, section 3 of the Baringa report entitled “I-SEM HLD Consultation: Background paper on HLD Option 3” and section 3.3 of the Baringa report entitled “Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper”.[44]

“… [S]cheduling risk is unlikely to be eliminated under the new market design since dispatch still relies on the outcomes from a central algorithm (in this case EUPHEMIA) which market participants may not be able to anticipate reliably, particularly in the absence of a Bidding Code of Practice. EUPHEMIA supports complex and sophisticated offer formats to help participants manage their technical and commercial constraints within the day-ahead scheduling process. However, with the exception of the possible partial acceptance on profile offers, complex or sophisticated orders can normally only be executed fully or rejected fully, and this constraint can lead to EUPHEMIA rejecting some complex orders even if they are priced below the outturn market prices. Rejected orders that are apparently in-the-money at outturn prices are termed ‘paradoxically rejected orders’ in the EUPEHMIA literature.”[45]

[44] Please note the relevance of the commentary referenced is not limited to the use of MIC orders in EUPHEMIA and applies equally to the use of block order formats as envisaged in paragraphs 1.5.8 to 1.5.12 of Annex B of the DDP.

[45] “Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper” p.8

It is also evidenced by the reference to and explanation of "paradoxically rejected block orders" in section 6.3 of the Euphemia Public Description and slide 65 of the presentation "EUPHEMIA: Description and functioning".[46]

### 5.1.2 Dynamic Scheduling Risk

Dynamic scheduling risk arises as a result of the partial modelling of generator commercial and technical characteristics within the EUPHEMIA algorithm. In the current SEM generating companies submit commercial and technical data that appropriately model the characteristics of each generating unit to facilitate the scheduling algorithm to determine least cost generation schedules for the market while ensuring cost recovery for generators. Under the proposed energy trading arrangements this will no longer be the case and generators will have to choose between exposure to volume or price risk when formulating commercial offers for the DAM.

#### 5.1.2.1 Volume Risk v Price Risk

To eliminate price risk generators will need to set a minimum production volume within their commercial offer submissions to the DAM, this facilitates the recovery of start-up and no load costs. However, to the extent that the minimum production volume chosen cannot be accommodated in the EUPHEMIA solution (due to the combination of the demand level in the DAM net of renewable generation and the commercial offer strategies of other generators), then the generator faces exclusion from the DAM schedule – i.e. volume risk.[47] To eliminate exposure to volume risk, a generator must increase its exposure to price risk – i.e. choose not to set a minimum production volume and thereby accept that the resulting DAM schedule it receives may not be technically feasible or sufficient to facilitate full cost recovery. As Baringa observe in relation to the use of linked block orders:

"… [T]he offer strategy for a single asset using Linked Block Orders will face choices about how to spread start-up and no load costs across the parent and child block prices. Loading the full possible start-up cost and no-load cost into the parent block increases the risk that the parent will be out-of-the-money, although these losses may be offset by positive margins on child blocks in determining the final clearing outcome. On the other hand, spreading no-load or start costs across child blocks increases the competitiveness of the parent block, but at the risk of cost under-recovery if child blocks are not cleared with the parent. The examples in Section 4 (albeit simplified through imposing an exogenous change to market price) demonstrated how sensitive offer acceptance could be. Taken together with the

[46] These documents can be found at the following links:
https://www.n2ex.com/digitalAssets/89/89745_euphemia---public-description---nov-2013.pdf
http://www.eirgrid.com/media/PCR_EUPHEMIA_CLARIFICATION.pdf

[47] An example of this would be if a generator that was normally 'baseload' submitted a commercial offer with a minimum production volume of a baseload profile set at its minimum stable generation level (using a block with a minimum acceptance ratio of 1) on a trading day when price taking offers in the DAM were sufficient to meet bids during periods of low 'demand'. The generator will not be scheduled by EUPHEMIA, despite being low cost generation and being required during periods of higher 'demand'.

potential for paradoxically rejected bids this highlights the potential for significant scheduling risk associated with judgements around offer parameter choices."[48]

The dynamics around the need for generators to balance volume against price risk under the proposed energy trading arrangements are discussed in detail in section 4 of the Baringa report "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper". This section also includes numerous worked examples.[49]

The salient question for the HLD, therefore, is whether the proposed approach to operating the DAM will lead to efficient price and scheduling outcomes, increasing costs to I-SEM consumers.

### 5.1.2.2 Information Symmetry, Predictability and Efficiency

For the DAM outcome to be efficient (in the sense of stable prices and least cost, economic schedules) sufficient information must be available to each generating company to allow them to construct offers that will achieve an economic merit order dispatch through EUPHEMIA. In the context of the I-SEM this requires an effective market power mitigation strategy and a reasonable level of predictability in market dynamics, including how other participants will tend to react to changing market conditions such as the level of wind generation and demand. This is described by NERA in the following terms:

"Unlike a despatch programme, Euphemia does not accept offers and bids in a structure that accurately reflects the costs and technical characteristics of individual generators. Instead, Euphemia offers market participants several ways to submit data that are intended to reflect generator characteristics in simplified offer formats. Generators have to choose which of these simplified offer formats best reflects their actual characteristics and how to adjust input data for differences between the simplified offer formats and the complex reality. This discretion over the choice of offer format creates a degree of unpredictability for each user of the system. Different market participants may choose to reflect the complex characteristics of their generators in different ways in response to changing assumptions regarding key attributes of the DAM such as the level of wind generation or demand. The actual outcome achieved by each market participant will then depend not only on how they adapt their own offers for any given day, but also on their ability to predict how other market participants will adapt their offers.

No final assessment of the Options will be possible if the SEM Committee cannot be sure that generators have the means to achieve predictable levels of output, consistent with economic merit-order despatch. …"[50]

[48] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.28
[49] Please note, we are ignoring MIC offers in this discussion as the proposed decision in paragraph 1.5.7 of Annex B suggests that these are not required. Our original response to the HLD consultation (and supported by third part consultancy advice) has already identified significant potential issues with the widespread use of MIC offer formats in the I-SEM.
[50] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 80 and 81 on page 19

The risk of inefficient DAM outcomes under the proposed design is explained by Baringa as follows (please note their concern regarding inefficient price volatility, forward market liquidity and inefficient market coupling):

"There is a further consideration as to how the combined strategies across the market may interact within the algorithm and how this could affect clearing prices in the auction. This is obviously contingent on the interaction between multiple strategies across different market participants, and is also likely to be dynamic, as strategies are evolved based on experience and observation of competitors. However, there is a concern that the consequence of strategies designed to mitigate scheduling risk, when translated across the market, could lead to inefficient outcomes. For example, if a material number of mid-merit plant were to zero-bid, this could exacerbate an issue that will face the market anyway as wind deployment increases, potentially leading to spuriously low prices at times, possibly combined with spikes as more peaking plant are required to create required shape. Such inefficient volatility is likely to deter forward trading and new investment, to the extent that prices are in part an outcome of the specifics of EUPHEMIA and associated strategies, rather than fundamental costs. In a similar manner, interconnector flows could be distorted in an inefficient manner."[51]

The requirement for a degree of predictability in DAM dynamics is implicit in the SEM Committee assumption "that through repeated daily participation in the DAM, generators will 'learn' how to bid to achieve a consistently efficient outcome."[52] Energia would emphasise that the validity of this assumption has not been established evidentially. Furthermore, that the specific structure and generation mix of the I-SEM means it would be prudent for the SEM Committee to rigorously test this hypothesis in the interest of consumers.[53] As NERA note:

"Euphemia has been developed as a means of trading energy in other countries. Testing of Euphemia is required, to confirm the assumption that it provides a suitable basis for despatching generators in Irish conditions."[54]

In particular, the following aspects of the I-SEM may make it difficult for participants to learn to achieve an efficient outcome through the DAM:

1. The large volume of intermittent wind generation in the I-SEM that will lead to substantial day to day and within day changes in the residual demand met by thermal generation;
2. The lack of substantial volumes of flexible hydro or pumped storage generation to balance intermittent wind volume and facilitate reasonably steady state running profiles for more inflexible thermal generation;

[51] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.30-31
[52] Cross reference paragraph 6.4.32 of the DDP.
[53] Please note that a non-mandatory DAM would introduce further uncertainty into predicting the level of demand and intermittent generation within the DAM making it even harder for generators to formulate offers that through competitive selection would achieve an efficient market outcome.
[54] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 81 on p.19

3. The presence of ESB as a single, large, fuel diverse generation portfolio that will be submitting (and therefore will have the advantage of knowing) commercial offers for over 40% of the installed generation capacity in the I-SEM;[55] and
4. Within the context of 3), the weakening of the current BCoP meaning that the establishment of a competitive, economic merit order for the I-SEM is not guaranteed.

### 5.1.3 Potential Impact of Scheduling Risk on Competition

Given their large, fuel diverse generation portfolio ESB will be better positioned to manage scheduling risk in the I-SEM. This is because a large portfolio can diversify volume risk across its generation assets such that if one unit is not scheduled it is likely that another similar unit will be.

In relation to Dynamic Scheduling Risk, in the absence of a robustly enforced BCoP, the dominance of ESB is likely to undermine the competitiveness of the selection process within the DAM under the proposed HLD. The requirement for generators to anticipate the bidding behaviours of other market participants when formulating offers for the DAM (as well as other key parameters for the DAM such as the profile of wind generation and demand) means a portfolio player such as ESB will have a substantial information advantage going into the DAM compared to other generating companies.[56] This will allow ESB to accrue significant portfolio benefits in terms of minimising downside scheduling risk and influencing DAM outcomes.[57] Baringa describe these potential advantages as follows:

"[H]aving a portfolio position is nevertheless likely to bring benefits. A portfolio player knows what the rest of its portfolio is doing with regards to commercial offers. In the context of the proposed High Level Design this provides an information advantage over a stand-alone generator who needs to guess this information to determine its most effective strategy. The advantage increases with the size of portfolio. In the current SEM this information asymmetry is managed through the Bidding Code of Practice which guarantees generators can compete on equal terms. However, without bidding principles it is very difficult to estimate the offer prices of competitors. Furthermore, it is not clear how unit-based bidding would in practice be interpreted where offers can be 'co-ordinated' across a portfolio. For example, with a hypothetical portfolio of three mid-merit plant, a strategy might involve zero-bidding for some volume of generation whilst offering capacity from other similar assets through parent/child offers placed at different times of the day."[58]

[55] References:http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf and http://www.esb.ie/main/about-esb/Generation-Plant.jsp
[56] ESB will be able to set a portfolio based strategy, and, from the point of view of other generating companies, will possess more knowledge about the DAM than any other participant – i.e. how the rest of their generation portfolio will offer into the DAM.
[57] It is worth noting that information asymmetry is not an issue in the current SEM because of the implementation of a rigorous BCoP strongly enforced through the monitoring of commercial offer submissions. This facilitates the establishment of a robust economic merit order and ensures generators can compete on a level playing field for spot market share.
[58] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.29-30

"… those players with a portfolio of assets are likely to be able to develop more sophisticated strategies over time, given the complex nature of the DAM in terms of offer structures and price setting. This may be especially true in a small market such as the I-SEM, where single plants represent a material share of the stack. It is likely that these players will aim to replicate the EUPHEMIA algorithm to develop and test these strategies, and assess the potential portfolio benefits in terms of an increased level of infra-marginal rent. … "[59]

Careful consideration should therefore be given to whether the proposed trading and scheduling arrangements for the DAM will undermine the conditions for effective competition in the generation sector in the I-SEM to the long-term detriment of consumers.[60] This should be a significant concern of the SEM Committee given ESB owns and operates over 40% of installed capacity, including strategically[61] significant flexible generation assets such as hydro and pumped storage. As Baringa note:

"It may prove very difficult from a regulatory perspective to distinguish between valid commercial strategies and strategies that are potentially anti-competitive or abuse a position of market power at certain times."[62]

### 5.1.4 Potential Issues with Non-mandatory participation in the DAM

Energia have concern that allowing non-mandatory participation in the DAM under the proposed HLD will increase unpredictability and therefore scheduling risk. As discussed in section 5.1.3 above, large portfolio players are better able to manage scheduling risk than stand-alone generators or small portfolios and this could therefore exacerbate concerns regarding long-term competition in the I-SEM generation sector. Non-mandatory participation would also introduce an additional level of unpredictability into the DAM offer creation process (the requirement to estimate how much wind generation and demand will choose to participate in the DAM as opposed to forecasting overall system wind generation and demand levels) and could therefore have a further detrimental effect on the efficiency of the outcome. Combined with the possibility that lower volumes will be traded through the DAM this could have a significant negative impact on forward market liquidity in the absence of physical forward trading and self-scheduling, undermining retail competition. Therefore Energia would stress that any move towards a non-mandatory DAM under the proposed HLD necessitates the introduction of a physical contract market and self-scheduling to mitigate against this risk. We would also note the observations,

[59] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.30

[60] We have further concerns regarding the ability of the HLD to deliver the conditions for appropriate competition in forward market timeframes. These were discussed at length in our original response to the HLD consultation. Cross reference sections 4.1 of that response (in particular sections 4.1.1 to 4.1.6) and section 2 (in particular, sections 2.3 to 2.5) of the Baringa report "I-SEM HLD Consultation: Promoting forward liquidity and mitigating market power in the I-SEM".

[61] Both from the TSO's point of view and ESB's own commercial point of view. As Baringa note on p.30 of their report "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper": "Given the potential for additional value to accrue to very flexible plant, then a portfolio with a significant proportion of such capacity could benefit."

[62] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.30

made by NERA, regarding the effect of changing fundamental aspects of the HLD on its performance against the SEM Committee assessment criteria.

"One effect of … [non-mandatory participation] would be to split trading volumes between the DAM and other markets, thereby reducing liquidity in all of them. Neither the DDP nor the IIA note the likelihood of this outcome. Instead, they take for granted the liquidity of the DAM under Option 3, an assumption based apparently on an earlier design, in which participation in the DAM was mandatory. The SEM Committee is therefore basing its appraisal of Option 3 on an out-dated specification."[63]

And again:

"The SEM Committee appears to have overlooked the implications of … [non-mandatory participation] for market liquidity. Its appraisal of Option 3 appears to be based on an out-dated version, which would perform differently from the latest version in terms of promoting liquidity. Since promoting liquidity is one of the supposed advantages of Option 3, the SEM Committee's decision, which relies on this feature of Option 3, must be regarded as unsound."[64]

## 5.2 *Forward Market*

As discussed at length in our previous consultation report and as set out in the Baringa report "I-SEM HLD Consultation: Promoting forward liquidity and mitigating market power in the I-SEM", forward market prices are the main drivers of retail pricing levels. Therefore a dysfunctional forward market increases costs to consumers, either through reduced retail competition or directly via the pass through of the premiums paid by suppliers on hedging products.

The current low level of forward market liquidity in the SEM is fundamentally a result of structural and market design issues.[65] These issues are the presence of ESB (a single, large, fuel diverse, generation portfolio with a large spot market share), combined with financial forward trading arrangements and centralised unit commitment. This view is supported by the obvious lack of effective competition in the current SEM forward market.[66] The current SEM arrangements also provide strong evidence that centralised unit commitment introduces scheduling risk[67] that increases forward market pricing levels[68] and dis-incentivises merchant generation from making forward sales at competitive prices.

[63] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 76 on p.18
[64] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 77 on p.18
[65] As evidenced in the Baringa report "I-SEM HLD Consultation: Promoting forward liquidity and mitigating market power in the I-SEM".
[66] See sections 2.3 to 2.5 of the Baringa report "I-SEM HLD Consultation: Promoting forward liquidity and mitigating market power in the I-SEM".
[67] See section 3.2 of the Baringa report "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper".
[68] The extracts reproduced below from ESB's liquidity proposals evidence the application of price premiums to manage the risk associated with supplying CfDs under the current SEM trading

As the proposed HLD does not address the structural issue identified above (financial forward contracting, centralised scheduling and the large, fuel diverse generation portfolio of ESB) it is extremely unlikely to change the current dynamics within the SEM forward market. In fact, the intention in the HLD to implement exclusive centralised scheduling of I-SEM generation without three-part commercial offers or detailed modelling of plant technical characteristics is likely to result in generators facing substantially more commercial risk when forward contracting. As Baringa observe:

"We believe that scheduling risk, present in the current SEM, is likely to endure and may increase under the proposed design, at least initially, impacting on forward market liquidity and prices."[69]

The trading arrangements chosen also exclude a wider range of SEM generators from providing a de-facto price cap on forward market pricing. An issue discussed at length within section 4 of our original response to the HLD consultation.[70]

While Energia acknowledges that financial contracts model the dynamics of physical contracts,[71] it is obvious that the volume risk associated with physical contracting in a market that allows a generator to self-schedule will be less than the volume risk associated with financial contracting in a market that centrally schedules all generation. This is because central scheduling removes the ability of the generator

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arrangements. Note that the price premiums applied to ESB's NDC products (on average up to €6.8/MWh sourced section 2.4.5 of the Baringa report "I-SEM HLD Consultation: Promoting forward liquidity and mitigating market power in the I-SEM") are significantly greater than ESB's actual availability risk (given their extensive generation portfolio) and therefore one must conclude that either the pricing of risk by ESB is uncompetitive or the level of scheduling risk in the current SEM trading arrangements is extensive. The extracts are reproduced in the CEPA report "Market Power and Liquidity in SEM" published 15th December 2015 (http://www.cepa.co.uk/editordocs/file/CER%20SEM-10.pdf).

*"A further aspect of regulation is the fact that benchmark products in the form of DCs are made available at the behest of the RAs and are priced with no risk premium thereby satisfying demand to a certain extent and undermining prices for CfDs."* P.140
*"Many participants in the physical SEM market want to be able to purchase SMP CfDs in order to reduce their own risk and exposure to the SMP but want such risk management products to be provided by somebody else and do not want to pay the premiums associated with buying out risk…. Whilst this is normal it is unreasonable."* P.142

[69] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.31

[70] Under self-scheduling arrangements the SRMC of a wider range of generators in the I-SEM would act as a cap on forward market pricing by facilitating participation by any generator in forward market timeframes, thereby increasing the competitive dynamics in the forward market. Please note the reasonably flat cost curve of a large number of CCGTs in the SEM meaning that small variances in SRMC can result in significant changes in market share for small portfolios / standalone generators. Any generator that is "in merit" in the forward market could sell forward in either retail or wholesale markets under self-scheduling arrangements without exposure to scheduling risk. However this would not result in out of merit generation being scheduled in the DAM as, acting rationally, a generator with a forward physical contract position has a strong economic incentive to bid below their SRMC in the DAM to maximise profits on forward sales. This could be mandated by introducing an Economic Purchase Obligation (EPO) on all generators by means of a license condition. The EPO would force the bidding of all physical bilateral contract positions held by generators into the DAM at or below SRMC to ensure liquidity and a strong reference price in that timeframe.

[71] Cross reference paragraph 6.4.3 in the DDP.

to choose to use its physical generation as a hedge for its forward contractual position and instead forces the generator to rely on the central scheduling algorithm to make this decision. To the extent that there is scheduling risk under the proposed Energia Trading Arrangements (as discussed in detail in Section 5.1 above) it manifests itself as additional commercial risk on a generator when making a forward sale. Depending on the perception of the materiality of this risk it will either undermine liquidity in the forward contract market or will result in a premium being applied to forward contract pricing levels, as evidenced through the application of risk premiums by ESB and others on unregulated forward contract sales under the current SEM. In either case the end result is an increase in costs for the consumer. As NERA observe:

"If [forward] contracts refer to the price in the DAM, generators who cannot predict their actual output at the day-ahead stage will be exposed to variation in the value of the difference between day-ahead sales and actual output ("volume risk"). Generators using renewable energy sources are particularly exposed to this risk but it will affect others who find it difficult to achieve a particular level of sales in Euphemia ("scheduling risk"). … If a generator cannot match its sales in the DAM to the volume of its CfDs settled by reference to the DAM price, it will be exposed to price risk on the difference. Generators will not be able to reduce this exposure by trading in intra-day markets … . The resulting increase in financial risk may raise the costs of generation borne by consumers through the wholesale electricity market."[72]

There is therefore the real concern that the proposed HLD could lead to a further reduction in forward market liquidity or even higher premiums being applied to unregulated I-SEM forward financial contracts than is evident today.[73] As Baringa observe:

"Managing the scheduling risk associated with this dynamic spot market position will introduce additional complexity for independent generators compared to the current SEM arrangements, and may lead to participants seeking a higher risk premium on forward contracts."[74]

Energia therefore strongly supports the decision to test the operation of EUPHEMIA as the central scheduling algorithm for the DAM. Given the importance of the efficiency of the DAM to the integrity of the proposed HLD (the level of scheduling risk is an indicator of inefficiency in the design) it is essential that rigorous testing is completed and all test data and results are published prior to the final decision on the HLD. This will provide market participants with confidence in the energy trading arrangements and help promote forward market liquidity prior to market go live (a

[72] "I-SEM Draft Decision SEM-14-045: A Review" paragraphs 91 and 92 on p.21. This is either through inefficient DAM outcomes or premiums on forward contracts.

[73] The potential issues identified here are a function of the efficiency of the centralised DAM scheduling process. As the efficiency of the DAM scheduling process increases the risks faced by generators (and therefore the cost to consumers – e.g. the risk premium on forward sales) decreases. Under self-scheduling arrangements the scheduling risk reduces to zero and the generator is left with the availability risk that exists under either scheduling arrangement.

[74] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.25

stated aim of the SEM Committee in the proposed HLD decision paper).[75] Energia also suggests that analysis is conducted to determine the level of risk premium required by generators to manage the scheduling risk associated with forward sales under the HLD. This analysis should also quantify the benefits accrued by portfolio players.

## 5.3 *Day-Ahead Market*

Energia strongly supports the intent of the HLD to deliver a liquid DAM to provide robust pricing signals, deliver efficient day ahead market schedules / coupling and ensure market access in spot timeframes, although we agree with the view of NERA that the HLD process has been too focused on these aspects at the expense of more fundamental design issues.[76] However, we disagree with the assumption of the SEM Committee that this can only be achieved by excluding physical forward contracting from the HLD in forward timeframes and implementation of central scheduling arrangements for generation. This does not seem to be the view held in other European electricity markets. We note from the proposed decision paper that the proposed HLD "is distinct from the arrangements in most, if not all, other markets in Europe".[77]

It should be noted that the liquidity promoting measures being suggested in the proposed decision[78] (presumably because of the potential relaxation of mandatory participation in the DAM) would work equally well under a design that facilitated forward physical trading and self-scheduling, as suggested in our response to the original consultation.[79] Furthermore, we suggested an Economic Purchase Obligation on dominant players[80] (which could be extended to all market participants should the RAs believe it necessary) that would mandate participants to submit bids below their SRMC facilitating the buying back of physical forward contract positions from the DAM; essentially delivering a centrally traded market with physical forward contracting and self-scheduling. We are therefore disappointed that this does not seem to have been properly considered by the SEM Committee in the evaluation of energy trading options. As NERA observe:

"Paragraph 5.5.5 of the Impact Assessment accepts that Option 3 would need unspecified additional measures to promote liquidity in forward markets. Judging by experience in Britain, allowing for such additional measures would be particularly important for the appraisal of Option 1. However, the Impact Assessment does not consider whether additional measures would allow the other Options to perform as

[75] Cross reference paragraph 6.4.6 on P.39 of the DDP.
[76] See section 3.2 of the NERA report "I-SEM Draft Decision SEM-14-045: A Review"
[77] Cross reference paragraph 6.4.5 of the proposed decision.
[78] Cross reference paragraph 6.4.27 of the proposed decision.
[79] The measures proposed by Energia are set out in detail in section 4.2.3.6 of our response to the original consultation.
[80] Cross reference mitigation measure vii in section 4.2.4.7 of our response to the original consultation.

well as, or better than, Option 3 in this respect or in any others (e.g. in day-ahead liquidity, for example)."[81]

The efficiency of the DAM is essential to the integrity of the HLD, both in terms of determining the starting position for dispatch and the reference price for financial contracts. As discussed in section 5.1, inefficiencies could arise in the DAM due to characteristics of the centralised scheduling algorithm (System Scheduling Risk), limitations in EUPHEMIA commercial offer formats combined with imperfections in the information available to participants when formulating offers (Dynamic Scheduling Risk) or market power.[82] If the outcome of the DAM is inefficient this will result in inefficiencies in dispatch and market coupling, increasing costs for I-SEM consumers.

Energia therefore welcomes the work carried out by the regulatory authorities on EUPHEMIA bid formats to date and strongly supports the decision communicated at the industry workshop on 17 June 2014 to test the outputs of the EUPHEMIA algorithm for the I-SEM DAM. Furthermore, we recommend that the testing programme includes dynamic modelling of potential generator bidding dynamics in the I-SEM, using Euphemia offer formats, to ensure that the hypothesis that "generators will 'learn' how to bid to achieve a consistently efficient outcome"[83] in the context of the I-SEM is verified evidentially rather than assumed and then asserted as fact in the DDP.[84] NERA have expressed the following view on this point:

"The SEM Committee assumes that market participants will find a way to achieve the desired – i.e. efficient – pattern of output from their generators, even though the primary route to despatch will be a trading algorithm (Euphemia) rather than a despatch programme. This assumption lies behind the SEM Committee's positive appraisal of Option 3 and its focus on the DAM. However, it is not a foregone conclusion that market participants will achieve an efficient pattern of output and demand through their use of Euphemia in the DAM or other markets. Assuming an efficient outcome is not a sound basis for the SEM Committee's decision …"[85]

NERA go on to advise that:

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81 "I-SEM Draft Decision SEM-14-045: A Review" paragraph 115 on p.26

82 The last two issues are addressed in the current SEM through the BCoP which ensures the formation of a robust economic merit order.

83 Cross reference paragraph 6.4.32 on P.45 of the Draft Decision Paper. The SEM Committee should note that generators are incentivised to maximise profits not deliver efficient outcomes. Accurate modelling of commercial costs and technical constraints via commercial offers to the DAM, combined with effective competition is required to establish an economic merit order and therefore deliver efficient outcomes. We have significant concerns regarding the ability of the HLD to deliver upon either of these requirements.

84 The I-SEM is a small market with a unique generation mix, characterised by a large volume of intermittent generation, balanced by relatively inflexible thermal generation compared with the large volumes of hydro generation in Nordpool and the Iberian markets. Therefore the use of offer types and trading dynamics within the I-SEM is likely to be unique within the European context as explained in section 2 of the Baringa report entitled "I-SEM HLD Consultation: Background paper on HLD Option 3", submitted as part of our original response to the HLD consultation.

85 "I-SEM Draft Decision SEM-14-045: A Review" paragraph 79 on p.18

"… Euphemia has been developed as a means of trading energy in other countries. Testing of Euphemia is required, to confirm the assumption that it provides a suitable basis for despatching generators in Irish conditions"[86]

Energia stress that it is essential that testing is conducted in an inclusive and transparent manner, with the direct involvement of market participants and the full publication of data. This will allow participants to gain confidence in the dynamics of the DAM and facilitate the modelling of EUPHEMIA by participants reducing the risk that any uncertainty regarding the energy trading arrangements (given that they are unique within Europe) will negatively impact liquidity and pricing in the I-SEM forward market.

Energia understands that the philosophy of the DAM under this design is that "[m]arket participants … will take responsibility for their own start-up and no load cost recovery and will internalise their own risks of commitment and scheduling through their offer decisions"[87]. Internalising these commercial risks however does not make them disappear. The costs associated with these commercial risks will need to be recovered in other areas to avoid a revenue adequacy issue caused by the HLD.

Furthermore, as discussed in section 5.1.3 above, there is clearly a significant benefit accrued by a large portfolio player such as ESB when internalising these risks. A large portfolio player will have additional information compared to other generators (the bidding strategy of their generating units) that will allow them to diversify their volume and price risk while influencing the level of exposure experienced by other generating companies. This issue is particularly acute in the I-SEM where ESB owns over 40% of the controllable generation capacity, including pumped storage that can adjust both generation and demand levels at key stress periods of the day. We therefore request that serious consideration to the management of information asymmetry in the proposed energy trading arrangements and its potential effect on the efficiency of the HLD. We also request that the SEM Committee give careful consideration to the negative long-term implications the HLD is likely to have for competition in the generation and retail sectors of the I-SEM and note the concerns raised by NERA[88] and Baringa in relation to market power.[89]

## 5.4 *Intra-Day Market*

Energia strongly supports the intent of the HLD to deliver an exclusive liquid IDM to provide access to market to manage imbalance exposures. We have concerns however that the EU platforms may not be available to facilitate exclusive intra-day trading as envisaged under the HLD and therefore, as a pragmatic measure, we suggest that back-up alternative arrangements are considered as an interim solution for intra-day trading.

[86] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 81 on p.19
[87] Cross reference paragraph 6.4.33 of the proposed decision.
[88] See paragraph 221 on p50 of the NERA report "I-SEM Draft Decision SEM-14-045: A Review"
[89] Cross reference section 5.1.3 above.

Given the nature of the chosen DAM arrangements, in particular the exclusive scheduling of physical generation through the DAM and the increased risk of receiving technically infeasible schedules, we have concerns that a large portfolio player such as ESB may be able to extract a further benefit from the HLD by effectively being able to rely on cashing out imbalance positions within their own generation portfolio at a single imbalance price.[90] This could significantly reduce liquidity in the IDM and further undermine competition in the I-SEM generation sector. As Baringa observe:

"We note that the High Level Design proposal for a single price cash-out means that longs and shorts in a generation portfolio will effectively net out. While unit bidding is proposed for the DAM and IDM, cash-out will be at a portfolio level. This would potentially advantage portfolio players and reduce within day liquidity … ."[91]

Even if this was prevented (e.g. by implementing a dual imbalance price) a large portfolio player will still be in a position to circumvent the intent of implementing unit bidding in the IDM because they have the ability to trade out positions within their own generation portfolio.[92] This again is an issue of information asymmetry, where the portfolio player can redress imbalances (e.g. caused by receiving technical infeasible schedules from the DAM) within its own portfolio first, albeit executed via the IDM platform, whereas other participants are forced to go to the market to trade out their positions. We therefore reiterate our request that careful consideration is given to the management of information asymmetry under the HLD and its potential effect on competition in the I-SEM generation sector.

## 5.5 *Balancing Market*

Energia strongly emphasises the need for clarity on balancing arrangements, in particular the interaction between energy markets, system security trades and the balancing market. We have identified below some of the issues that require further clarification through the detailed design phase. Furthermore, we would strongly advise that the lack of clarity on the intent of the design in these and other areas has seriously undermined the ability of participants and the SEM Committee to properly evaluate the HLD options consulted upon. This is also a view expressed by NERA in section 5.2 of their report "I-SEM Draft Decision SEM-14-045: A Review".

[90] Within a portfolio, if unit X is long by 10MWh, unit Y is short by 15MWh and unit Z is long by 5MWh then the net imbalance across the portfolio is 0MWh if there is only a single imbalance price. This is because the payment received on the long positions for unit X and Z will fully offset the price paid on the short position of unit Y. It should be noted that the benefit of netting across a portfolio will increase significantly in relation to its size.

[91] "Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper" p.30

[92] Within a portfolio, if unit X is long by 10MWh, unit Y is short by 15MWh and unit Z is long by 5MWh then the portfolio can generate a trading strategy whereby unit X and unit Z trade their imbalance position with unit Y reducing the portfolio's net imbalance position to 0MWh. The portfolio can easily co-ordinate its execution of these transactions to the detriment of other generating companies because it has the required information available to it to execute its trading strategy quickly. It should be noted that the benefit accrued by a portfolio through imbalance trading strategies will increase significantly in relation to its size.

1. Is the intention of the design that generators will receive technically feasible indicative dispatch instructions from the TSO following the DAM. If so, what is the proposed process for achieving this and what is the intended balance of commercial risk between the generator and the TSO? Will the generator be exposed to the IDM and balancing market for the difference between its DAM schedule and indicative dispatch instruction or will this difference be settled with reference to the DAM commercial offers of the generator and the cost socialised via a charge to consumers similar to the current constraint payment mechanism in the SEM?

2. Is the intention of the HLD to limit TSO security actions until after the DAM schedule is produced? This is necessary under a pay as bid regime for non-energy balancing actions[93] to ensure generators are able to manage their exposure under financial forward contracts and reliability obligations (assuming these will be referenced to the DAM). If the TSO can execute non-energy balancing actions prior to the DAM then the generator must either be released from their contractual obligations under financial forward contracts[94] and reliability options (if referenced to the DAM), or be kept whole against the DAM price.

3. Is the intention for the TSO to take energy balancing actions prior to intra-day gate closure? We see this concept as potentially problematic in that the energy balancing actions required will only be known after all intra-day trading has been completed. If the TSO conduct energy balancing actions prior to intra-day gate closure any participant could countertrade the position taken by the TSO and necessitate further action to be taken. See section 5.3.2 of the NERA report.

4. Will participants be able to countertrade non-energy balancing actions in the energy market? If they are locked into the non-energy balancing action (removed from the energy market by the TSO) generators need to be able to recover their lost opportunity of trading in energy markets. Furthermore, if the same bids and offers are used for energy and non-energy balancing actions then balancing market pricing may be distorted by the lost opportunity costs included by generators for non-energy actions.

5. The rules for tagging and flagging of energy and non-energy balancing actions by the TSO need to be carefully considered and worked through to ensure there is transparency and a high level of market confidence in this process. The tagging and flagging of trades must be based on objective criteria and be easily verifiable by market participants.

6. The rules around setting the imbalance price need to be carefully considered. For example, will imbalance pricing take account of the technical limitations of

[93] We are assuming the TSO will not take energy balancing actions prior to the close of the IDM.
[94] This is not a realistic, viable solution.

plant – i.e. will a unit only set the price if it actually delivers the change in energy output it is instructed to?

7. Start up, shout down and no-load costs must be recoverable in the balancing market to ensure adequate cost recovery. It should also be noted that generators will need to make assumptions regarding their commitment state in the DAM. These assumptions could be invalidated due to balancing actions taken by the TSO generators further reinforcing the need to reflect these costs within balancing market bids.[95]

## 5.6 *Credit Requirements and Working Capital*

Energia would strongly emphasise that increases in credit or working capital requirements are a significant burden on generators, energy supply companies and traders. Any increase in credit or working capital requirements under the I-SEM HLD will:

1. Increase the cost of market participation;
2. Act as a barrier to new entry;
3. Discourage effective competition (both in terms of new entry and discouraging existing supply companies from growing their market share); and therefore
4. Increase costs for I-SEM consumers.

It is therefore essential that the I-SEM market design focuses on minimising these costs for both the capacity and energy markets (across all timeframes).[96] While Energia acknowledges the sentiment expressed in the IIA that under the I-SEM design daily settlement may reduce collateral requirements,[97] no consideration seems to have been given to the negative impacts of the substantial increase in working capital this necessarily entails for supply companies.[98]

Energia would also emphasise that imposing onerous credit requirements for forward contracting could be used by a dominant entity to choke off retail competition in the I-SEM. The reality of this risk and the concern it has generated in other markets is evidenced by the detailed mitigation measures introduced by Ofgem into the GB

[95] As Baringa observe on p5 of their report “Scheduling risk under the proposed I-SEM High Level Design: An Issues Paper”:
“In pricing their balancing bids and offers, generators will need to consider the impacts on their assumed starting positions used for preparing offers into the next day’s DAM. For example, had the generator assumed that it would begin the day generating, any bid to switch off in the balancing market would need to factor in the costs of re-starting the plant (which were not included in the DAM offer price).”
[96] Cross reference section 6.3.8 detailing the increased collateral requirements for generators and potential cash flow implications of Reliability Options.
[97] Cross reference paragraph 2.1.20 of the IIA.
[98] Daily settlement increases the deficits in cash flow between market settlement and the customer billing cycle.

wholesale electricity market through their 'Secure and Promote' provisions[99]. In the interests of competition we therefore strongly recommend that the SEM Committee ensure that the credit requirements imposed by ESB on counterparties when contracting in the I-SEM regulated and unregulated forward markets are evidenced to be proportionate to the commercial risks.

## 5.7 *Implications for key SEM Committee policy objectives*

Energia are concerned that the implications of the HLD for key policy considerations has not been given sufficient consideration by the SEM Committee during the consultation process. A few key examples are highlighted below:

1. It is not immediately clear how the current policy on losses can be easily translated into a market that requires demand to actively bid into an ex-ante market. In the current SEM losses are included in the market demand by virtue of it being set equal to total generator metered output. This approach is not possible in an ex-ante market with demand side bidding.

2. It is not immediately clear how the current policy on firm / non-firm access can be easily translated to an ex-ante market because the real-time dispatch of a generator with non-firm access is unknown at the time of participation in the DAM and IDM.

3. It is not immediately clear how the concept of a Variable Price Taker (which is central to key renewable policies in the current SEM such as tie break rules etc.) is easily translated into the proposed arrangements.

Energia are therefore concerned that the regulatory authorities have significantly underestimated the work required during the detailed design to address these and other material gaps in the proposed HLD.

## 5.8 *Market Power*

The presence of ESB as a single, large, fuel diverse generation portfolio in the I-SEM means that market power remains a significant concern for the I-SEM across all energy market timeframes. This was stated in 2010 by CEPA[100] and confirmed by the RAs as recently as 2012 in their decision on ESB horizontal integration.[101] Energia therefore welcomes the recognition given in the proposed decision to the importance of effective market power mitigation measures and a robust market monitoring framework.

We would however emphasise that if ex-ante bidding principles are implemented for I-SEM that care is taken not to tie the hands of generators with regards to their ability

[99] Cross reference Section 3 of the Ofgem 'Secure and Promote' provision published at https://www.ofgem.gov.uk/ofgem-publications/39302/liquidity-final-proposals-120613.pdf
[100] See their report "Market Power and Liquidity in SEM: A report for the CER and the Utility Regulator" which can be sourced from http://www.cepa.co.uk/editordocs/file/CER%20SEM-10.pdf
[101] See SEM-12-002 which can be sourced from http://www.allislandproject.org/en/sem_publications.aspx?year=2012&section=2

to manage their commercial risk across the respective market timeframes. In addition, if a quantity based capacity mechanism is introduced a generator that does not secure a capacity contract will have to maximise its revenues through the energy market to try to recoup its fixed costs. Furthermore, the subjective nature of the assumptions that generators will be required to make when formulating bids and offers under the HLD will make objectively establishing the intention of bidding behaviours significantly more difficult.[102] At a high level it is much easier to police inputs (as is the case with the current SEM BCoP) than market outputs (which will be the situation under I-SEM). However, we acknowledge that a robust legislative framework for market monitoring will be in place for I-SEM under the Market Abuse Directive (MAD) and the Regulation on Energy Market integrity and Transparency (REMIT). Nevertheless, we strongly suggest the SEM Committee should give careful consideration to whether this generic legislative framework is capable of managing the specific competition issues of the I-SEM that are outlined in this report.

Significant importance has been placed on the ability of interconnection with other markets to limit market power. Energia would emphasise that the level of interconnection in the I-SEM will be the same as under the current SEM (prior to the current Moyle outage). Furthermore that the current market arrangements result in predominantly imports to SEM rather than exports to GB. Assuming that current flows on the interconnector are sub-optimal one would therefore expect an increase in the levels of exports to GB when flows are optimised. As exports raise the demand levels in the SEM, efficient market coupling is likely to increase the potential opportunities to exert local market power[103] rather than reduce them, particularly with the weakening of the BCoP. This dynamic was identified by CEPA and is commented on by NERA below.

"CEPA … noted that ESB would be pivotal more often, if electricity prices were higher in Great Britain than in the SEM, as the additional interconnector exports from the I-SEM to the British market would then raise demand on generation resources in the SEM, instead of providing a competitive substitute for them."[104]

The prudent approach therefore would be to assume that SEM interconnection is fully exporting from SEM to GB for the purposes of assessing spot market power in the I-SEM. A similar argument can be made regarding the need to prudently assess capacity adequacy in the I-SEM.

As discussed in section 5.1 and 5.3 above, Energia is concerned that the information asymmetry due to structural issues in the I-SEM will result in inequitable access to market in the HLD. In particular, the requirement for generators to internalise their start up and no load costs and risks of scheduling and commitment mean that

[102] The subjectivity of assumptions around other generator's bidding strategies etc. and the difficulty of managing commercial risk and technical feasibility in the context of the DAM along with its implications for market power mitigation are discussed in more detail is section 5.1 above.

[103] In the sense that the interconnector under I-SEM becomes a localised constraint in the pan-European electricity market.

[104] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 199 on p.44

portfolio players will have an inherent advantage given the increased market information they hold when formulating bidding strategies, particularly in the DAM. As ESB own the only large, fuel diverse generation portfolio operating in the I-SEM this could have detrimental effects on the conditions for effective competition in the generation sector resulting in long-term negative effects for consumers.

We therefore reiterate our view that forward physical contracting and self-scheduling (which could be incorporated as a variation of Option 3) would provide effective market led mitigation against the exertion of market power in forward and DAM timeframes and strongly suggest that this should be reconsidered as an adaptation to the proposed HLD. Forward physical contracting and self-scheduling provides generators with more choice regarding the type of exposure they hold to the DAM.[105] Under such arrangements generators can chose to:

1. Self-schedule, guaranteeing competitive access to the forward market, and then optimise trade positions through the DAM (Energia suggest that this could take the form of mandated bids for physically forward contracted generation);
2. Schedule through the DAM by submitting offers for physically un-contracted generation (as is the mandated approach under the proposed HLD option); or
3. A combination of 1) and 2).

Providing a wider and more effective suite of risk management approaches for generators is in line with other European electricity markets and will reduce scheduling risk, improve conditions for competition in forward markets and thereby reduce premiums on forward contracts, lowering costs for I-SEM consumer. It will also limit any potentially negative impact on competition of an inappropriate exertion of market power in the retail or generation sector.

In the absence of physical forward contracting and self-scheduling it would seem prudent to either re-introduce ring fencing across ESB's generation assets or significantly increase the level of directed forward contracts. The SEM Committee should note that ring fencing was removed because of the protection offered to the consumer through the BCoP. The relevant sections of the decision are reproduced below:

"CEPA states in the December paper that, with BCoP in place, *"the operational horizontal separation of ESB seems to have little value in promoting competition, whilst adding some cost to ESB, and thus an operational integration should be considered".* Thus it believes that horizontal ring-fencing could be removed because the operational efficiency benefits in doing so might be worth the small market power risk. This is because BCoP and the MMU help ensure that all generator bids are at

[105] Our arguments focus on generator's participation in the DAM because the risks associated with this, along with the price signals generated by the forward market, will determine the efficiency of the forward market and therefore the energy prices paid by suppliers and ultimately consumers. See section 5.2 above.

appropriate SRMC levels, irrespective of horizontal integration, and indeed DCs provide further protection in this regard. There would not be the higher market power risks associated with full vertical integration (see above).

ESB could make generation cost savings from horizontal integration, with low market power risks for the end customer. Any efficiency gain would be welcome, especially in the current economic climate." [106]

Given the weakening of the BCoP and the potential reinforcing of ESB dominance within the HLD (ESB will own and operate the only extensive generation portfolio in the I-SEM and therefore will disproportionally accrue the significant portfolio benefits identified in this report), as noted by CEPA in their 2010 report the reintroducing effective ring fencing would improve the structural basis for competition in forward and spot timeframes. In the absence of the reintroduction of ring fencing a significant increase in directed contract volumes (or similar regulated forward contracts) is required to mitigate the incentives to exert market power in both forward and DAM timeframes.

Regardless of the reintroduction of ring fencing however we would strongly recommend that the market power mitigation measures we suggested for Option 3 in section 4.2.3.6 of our original response to the HLD consultation are implemented.

### 5.8.1 Provision of Renewable Aggregation Services

Energia would emphasise the risk that Eirgrid could effectively monopolise delivery of the provision of aggregation services to renewable generators. Therefore careful consideration needs to be given to the set-up of the aggregator of last resort service in the I-SEM. We would stress the need for market participants to be able to compete economically against Eirgrid for the delivery of aggregation services to ensure there is sufficient scope for effective competition to emerge within the I-SEM in this sector. Incentivising competition will reduce costs and maximise benefits for renewable generation.

[106] SEM-12-002 p.19

**Summary of Energia's response to the Proposed Energy Trading Arrangements**

- The efficiency of the DAM schedules and pricing is fundamental to the success of the HLD across all energy market timeframes. Under reliability options it is also essential to the operation of the capacity market. As stated by NERA, it is not a foregone conclusion that the DAM will produce efficient prices and schedules. Therefore it is essential that the SEM Committee test EUPHEMIA prior to making a final decision on the HLD. This testing should be open and transparent with full publication of data to provide confidence to market participants regarding the HLD and to avoid any potential negative effect on liquidity in forward markets prior to commencement of the I-SEM. Testing should focus on the impact of the dynamic interaction of generator bidding behaviours through EUPHEMIA to changing market conditions, including the bidding strategies of other generators. The need for testing in this area is evidenced by both the NERA and Baringa reports.
- Scheduling risk under the proposed market design is an indicator of the efficiency of the DAM. As discussed in section 5.1 and confirmed by Baringa, scheduling risk is likely to increase under the HLD. As evidenced by Baringa and NERA, increased scheduling risk for generators will lead to higher costs for consumers through inefficient DAM schedules and prices. It will also undermine liquidity in the forward market, negatively effecting retail competition, and increasing risk premiums on forward contracts.
- We have identified that substantial benefits will accrue to ESB under the HLD because of their extensive range of generation technologies and consequently their ability to formulate and effectively execute portfolio strategies to minimise scheduling risk and influence market outcomes (due to the information advantage they will have over other generating companies). This conclusion is supported by Baringa. Therefore the HLD re-enforces ESB dominance in the spot markets and will further exacerbate competition issues in the I-SEM generation sector. The dominant position of ESB in the I-SEM generation sector was stated by CEPA in 2010 and confirmed by the SEM Committee in 2012.
- We highlight that interconnection with GB will not provide a remedy to ESB dominance given the expectation of significant increases in exports from I-SEM to GB. This is a conclusion supporting by CEPA in their 2010 report.
- We have identified the potential issues of implementing a robust market power mitigation strategy within the context of the HLD. In particular, the difficulty of implementing a BCoP. We strongly emphasise that generators need significant flexibility to manage their commercial and technical risks. This strongly reinforces the need for increased volumes of directed contracts (or similar regulated forward contracts) in the absence of the reintroduction of horizontal ring fencing on ESB.
- We question whether the generic legal framework provided by REMIT and MAD will be sufficient to manage the specific structural market power issues within the I-SEM.
- We note that the HLD does not address the structural issues within the current SEM leading to a lack of competition in the forward market. The HLD will therefore re-enforce the dominant position of ESB in the I-SEM forward market to the detriment of retail competition and the I-SEM consumer.
- We therefore conclude that the HLD will promote ESB dominance in both the retail and generation sectors of the I-SEM to the detriment of competition and ultimately I-SEM consumers.

- We restate our position that forward physical contracting and self-scheduling combined with an Economic Purchase Obligation will provide market led mitigation to ESB dominance and fully deliver upon the requirements of the EU target model. We believe this proposal has not been given due consideration by the SEM Committee in the HLD decision process.
- We note that non-mandatory participation in the DAM will undermine liquidity in the DAM (the key perceived benefit of Option 3) and therefore the forward market (in the absence of physical forwarding contracting and self-scheduling), undermining retail competition in the I-SEM. It will also increase uncertainty around key parameters of the DAM and therefore scheduling risk leading to less efficient schedule and price outcomes, increased risk premiums on forward contracts and lower forward market liquidity. This further re-enforces ESB dominance in the I-SEM generation and retail sectors.
- As a practical, pragmatic measure we emphasise the need for a back-up solution to support the IDM in case the European platform is not available.
- We stress the need to minimise credit and working capital requirements to promote new entry and growth of competition in retail markets and emphasise the need for the SEM Committee to regulate the credit requirements of ESB for regulated and unregulated contract sales to ensure they are evidenced to be proportional to the commercial risks. The need for such regulation to foster competition in retail markets is evidenced by Ofgem in their introduction of the 'Secure and Promote' provisions.
- We would stress the need for market participants to be able to compete economically against Eirgrid to deliver an aggregation service for renewable generators. Given the potential for Eirgrid to monopolise the delivery of this service careful consideration needs to be given to the set-up of the aggregator of last resort in the I-SEM to ensure there is sufficient scope for effective competition to emerge for the delivery of this service, reducing costs and maximise benefits for renewable generation.

# 6 Capacity Remuneration Mechanism

In this section we discuss the capacity remuneration mechanism (CRM) for I-SEM and consider in particular the scheme proposed in the draft decision (i.e. Option 5a: Centralised Reliability Options).

The SEM Committee's appreciation of the continued need for an explicit capacity mechanism to resolve the 'missing money problem' is welcome. There is a compelling need for a well-designed mechanism tailored to address this problem in the all-island context given the small size of the market and its pronounced sensitivity to single entry or exit decisions. This is borne out in EirGrid's assessment of generation adequacy for an energy only market which helps to illustrate that concerns over security of supply would quickly arise due to the small size of the market; the potential for the market to oscillate between surpluses and shortages; and the risk attached to a reliance on extreme electricity prices to attract and retain investment[107].

In light of above, the chosen CRM must address the missing money problem and replace revenues from energy price spikes with a smoothed payment for capacity. The mechanism should be designed to mitigate market power and the potential for predatory pricing or non-commercial objectives to distort capacity prices down.[108] Inefficient exit is a real risk in this scenario which could further enhance market power in the energy market, undermine retail competition and force the use of more expensive capacity. The propensity for capacity prices determined by auction to be highly volatile in a small system, as explained by NERA, should also be recognised. In addition the adverse impact of coordination problems and demand shocks in a small system (as explained in our response to SEM-14-008) should be taken into account, which further underlines the need for a mechanism which dampens the volatility of revenues[109]. Potentially significant adverse effects of the proposed CRM design, discussed further below, should be taken into consideration. Finally, claims of a particular design being consistent with 'international best practice'[110] should be carefully grounded in fact. It is simply not the case that reliability options as proposed constitute 'international best practice', as we also discuss further below. For example the RAs repeatedly refer to ISO New England as an example of the scheme they are proposing but this scheme is currently undergoing significant reform to address problems with its performance. The Colombian scheme referred to also has its own problems.

[107] This is a risk the TSOs identify as especially acute if less reliance on interconnector imports is assumed and if a tighter adequacy standard of 3 hours LOLE/year, is adopted in line with the standard used in France and proposed for GB. In addition, the TSOs explicitly caveat that their assessment of generator exit represents a lower bound: "Assuming a lower figure for the average price that a generator can obtain could lead to more generation being removed, and a lower capacity surplus (or greater shortfall) in many cases" (page 22).

[108] For further explanation see section 5.1 of our response to SEM-14-008 and page 19 of the April 2014 NERA report for Viridian.

[109] For further explanation see section 5.1 of our response to SEM-14-008.

[110] The initial impact assessment and draft decision repeatedly refer to the chosen CRM design as being consistent with 'international best practice'.

Any decision to proceed with a CRM design which does not demonstrably address the above concerns should at least explain why they are not considered relevant. It is essential that the SEM Committee do not take a short-term and opportunistic approach when determining the I-SEM CRM as this will undermine investor confidence and damage the long term interests of the consumer[111]. It would also be contrary to CRM objectives of stabilising prices and revenue streams over the longer term – e.g. the IIA indicates the capacity price based on reliability options being near zero in 2017. On the above points the April 2014 NERA report contains a discussion which is worth quoting:

"One of the principal motivations for having a capacity payment in the SEM is that, as a small market, it might otherwise by subject to spikes and troughs in prices as new capacity was retired or added to the system. For a capacity market to smooth prices in the SEM, the (implicit) demand curve for capacity must decline only gradually. Indeed, steep demand curves also increase the scope for the exercise of market power …[W]hilst there is currently surplus generating capacity in the all-island market, that does not justify removing capacity payments through introducing a steeply sloped demand curve. Such an "opportunistic" form of regulatory intervention will heighten regulatory risk, and exacerbate the market failure a CRM is designed to address" (pages 50-51).

## 6.1 *I-SEM Capacity Mechanism*

Energia welcomes the decision of the SEM Committee to maintain an explicit capacity mechanism for the I-SEM but we are disappointed that the reasoned views of the majority of SEM participants supporting the current approach have been ignored. We have particular concern that the SEM Committee's decision has been unduly influenced by an unhelpful and artificially drawn distinction, prevalent in the HLD consultation, between price-based and quantity-based CRMs. NERA have concluded that this distinction (and the characteristics prescribed to the CRMs labelled under it) has prejudiced the evaluation of CRMs by the SEM Committee and seriously calls into question claims of the proposed scheme being consistent with 'international best practice'.[112]

"The SEM Committee has therefore mischaracterised many CRMs and/or criticised price based schemes for possessing fixed price characteristics that do not exist in reality. This error has biased the SEM Committee's evaluation of CRMs and distorted its final choice. The draft decision is not therefore soundly based."[113]

Furthermore, NERA observe that the lack of detail provided in the HLD consultation paper regarding the CRMs presented for the I-SEM (and in the case of the proposed decision, the lack of detail regarding the form of reliability options) meant that it was

[111] For example, the potential consumer savings identified in the IIA appear to be based on purely financial reliability options which cannot solve the missing money problem and they exist nowhere else in the world.
[112] See section 6.2.3 of the NERA report "I-SEM Draft Decision SEM-14-045: A Review".
[113] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 168 on p.37

not possible for either the SEM Committee or market participants to conduct a proper or meaningful evaluation of the proposed options.[114]

"The SEM Committee will compile a more detailed design in the next phase, but no proper evaluation of the various CRMs is possible at this stage without considering at least some … [key] detailed design features. If the SEM Committee had considered these detailed design features, it might have reached a different decision."[115]

## 6.2 *Quantity Based CRMs*

There are a number of significant problems with introducing a quantity based CRM into the I-SEM that have not been given sufficient consideration in the draft HLD decision or impact assessment. These are discussed further below.

### 6.2.1 Market Power

Energia welcomes that there is some recognition by the SEM Committee of the issue of market power in the capacity market and we would emphasise that it is important to acknowledge the potential for predatory pricing and non-commercial objectives in this context. Given the structural characteristics of the all-island market (the dominance of ESB in the I-SEM capacity market) we do not accept that a quantity based mechanism is appropriate. For example on the question of choice between price versus quantity schemes, Battle and Rodilla (2010)[116] state that "this decision depends mainly on the regulators reliance on the market to determine the price of the product" (p. 35). In the I-SEM the market cannot be relied upon to efficiently determine the price of capacity because of the dominant position of ESB and the resulting concerns regarding market power. Energia therefore strongly advises against the implementation of a quantity based mechanism as the level of competition in the I-SEM capacity market will not be sufficient to support an efficient market based valuation of capacity and therefore significant regulatory intervention will be required to protect the interest of consumers. Furthermore, we recommend that careful consideration is given to the market power mitigation measures required under a quantity based mechanism and request that the SEM Committee rigorously assess the feasibility of implementing these effectively. As NERA caution:

"A single, centralised auction provides sufficient opportunities for abusing market rules, as well as for signalling between participants, to merit concern about market power… In the New England market, bidders may not bid below the Minimum Offer Price and the market monitor scrutinises bids to make sure that buyers are not distorting the market by exerting downward pressure on prices" (page 47 of April 2014 NERA report).

[114] See section 6.1 of the NERA report "I-SEM Draft Decision SEM-14-045: A Review".
[115] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 130 on p.28
[116] Batlle, C., Rodilla, P. (2010), "A critical assessment of the different approaches aimed to secure electricity generation supply", IIT Working Paper IIT-10-017A, July 2010 (version subsequently published in Energy Policy, vol. 38, iss. 11, pp. 7169-7179, November 2010).

"…[P]ure quantity based schemes may be more prone to abuse by dominant players – and might conceivably cause even more distortion of cross border flows. Experience in the United States shows that the price of capacity in a quantity based CRM is sensitive to generators withholding capacity (or increasing the supply of capacity and demand-side resources). The price of capacity in a pure price based schemes cannot be manipulated in this way and might cause less distortion of cross-border trade."[117]

The SEM Committee should also note the potential impact of market power mitigation measures on the validity of the assessment of CRM options conducted and presented in the DDP and IIA. As NERA state:

"Any regulatory intervention intended to counter market power in a competitive market runs the risk of adverse effects, because it may also distort or prevent pro-competitive bidding behaviour. No impact assessment would be complete unless it examined the regulatory interventions required by each kind of CRM and assessed the associated risks of adverse effects. By overlooking the need for regulatory interventions in auctions of Reliability Options, whilst recognising that need for other CRMs, the SEM Committee has biased its evaluation of the different mechanisms."[118]

As a minimum measure, Energia advises that a floor price for capacity auctions is required. The floor should be referenced to the cost of a best new entrant, similar to the current approach. This will reduce volatility in the capacity price and mitigate the risk of a predatory pricing strategy or non-commercial objectives to keep uneconomic plant open in capacity auctions, thereby guarding against a cycle of inappropriate plant exit and entry which would be to the detriment of I-SEM consumers as discussed below.[119]

### 6.2.2 Inappropriate Entry / Exit Cycles

A key objective of a capacity mechanism is to ensure security of supply through efficient investment. An auction based approach to determining the value of capacity could result in the reintroduction of significant volatility in capacity prices for existing plant, particularly in a small market such as the I-SEM. The pattern of this volatility is likely to be characterised by a flat lined capacity price with large capacity price spikes coinciding with times of required investment in capacity. By reintroducing volatility into capacity pricing in the I-SEM such a trend could result in the establishment of an inappropriate cycle of generator entry and exit. Extending the lead time between auctions and contracts may not be sufficient to reduce such volatility in a small market like the I-SEM because periods of capacity surplus or shortage can be easily identified and anticipated by the market in advance. As NERA point out:

[117] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 177 on p.39
[118] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 220 on p.50
[119] Predation in capacity markets is more difficult to detect than energy markets and a predatory pricing strategy (or the credible threat of such) is easier to deploy in a small system because the capacity margin is more sensitive to entry or exit decision. For further detailed explanation see April 2014 NERA report, Section B.3 of Appendix B.

"Due to the small size of the market in the SEM, the price of the ROs may still be volatile if investors can anticipate a shortage/surplus of capacity in the year for which ROs are being auctioned. Under current proposals, ROs would be auctioned up to 5 years ahead, but the situation in that year may well be predictable in the SEM, due to the impact of individual no-go investment decision on a small market"[120].

This is a recognised problem in practice and in the academic literature[121] and could be exacerbated given the high levels of concentration in the I-SEM capacity market if ESB (which owns over 40% of the installed dispatchable capacity in I-SEM)[122] adopted a strategy of predatory pricing, or was willing to keep uneconomic plant open for non-commercial reasons. It should be noted that extending lead times for auctions would not be sufficient to remove volatility caused by exertion of market power and therefore mitigation measures such as those suggested in 6.2.1 above are required.

### 6.2.3 The Double Payment Fallacy

As set out in section 7.4 of the DDP, the purpose of the I-SEM CRM is to replace "missing money" from the energy market. Therefore, by definition, under a well-designed CRM it should not be possible for a generator to extract a double payment for capacity from the energy market over the long term. This remains the case whether a so-called long-term price based CRM or a quantity based CRM is implemented. Therefore the risk of 'double payment' cannot be used as an argument against the current approach. As NERA clarify:

"When considering the introduction of a CRM, the designers sometimes ask whether it will lead to "double payment" of generators, i.e. if capacity will be remunerated twice over for the high value of electricity during peak periods – once in the energy market and once in the capacity market. In cases where the need for a CRM is based on the recognition of a "missing money" problem, however, such considerations no longer apply. The explicit purpose of a CRM is to provide a source of additional revenue, over and above the amount (whatever it is) that the energy market is expected to provide. In other words, if the CRM pays money which would otherwise be "missing", the question of double payment no longer applies."[123]

[120] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 190 on p.42

[121] Ref Battle and Rodilla (2010), IIT Working Paper, July 2010, pp.7-8 – i.e. a paper quoted by the RAs in footnote (subsequently published in Energy Policy as Batlle, C., Rodilla, P., 2010, page 21: "In (PJM, 2006) the PJM Market Monitor conducted an analysis in an attempt to assess whether the fixed costs of the different units were covered by the prices received by generators from the PJM markets plus the ICAP payments, and concluded that investments costs were not being recovered. In addition to this lack of investment cost recovery, there was another relevant problem linked to the design of these capacity markets: the extreme volatility of prices. Capacity market prices tended to alternate between very low prices, during the large periods where the system's reserve margin was large, and extreme high prices when not enough capacity resources were available (Chandley, 2005)".

[122] References:http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf and http://www.esb.ie/main/about-esb/Generation-Plant.jsp

[123] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 161 on p.36

The main difference between these approaches, based on how the distinction has been drawn within the HLD consultation paper, seems to be that a price based CRM relies on a centrally administered calculation of the "missing money", whereas a quantity based CRM assumes the market can determine the correct value competitively. The concerns outlined in section 6.2.1 above regarding market power in the I-SEM capacity market mean the latter approach is unlikely to result in a competitive outcome (unless there is significant regulation of the auction process to protect the long-term interests of I-SEM consumers and to guarantee security of supply).[124] Significant regulation of the auction process however simply moves the mechanism back towards an administered calculation of the "missing money" undermining the rationale for implementing a "quantity based" mechanism in the first place – i.e. the need for significant regulatory intervention is not unique to so called long-term price based mechanisms and therefore should not be used as an argument against such mechanisms, particularly within the context of the I-SEM. This view is corroborated in the NERA report:

"Measures to mitigate market power are also likely to be necessary in any centralised auction of capacity market instruments in the I-SEM. The SEM Committee recognises this need in the IIA, but ignores it in the DDP, frequently describing Reliability Options as "market-based", whilst highlighting the degree of regulatory intervention in other CRMs. This selectivity in describing the impact of market power mitigation has biased the SEM Committee's evaluation of CRMs for the I-SEM. As a result, we conclude that the SEM Committee has no reliable basis for assessing CRMs, or for selecting Reliability Options, with regard to their impact on competition."[125]

### 6.2.4 Increased Regulatory Risk

A quantity based mechanism requires a generator to value its capacity within the context of its other revenue streams – e.g. ancillary services and energy market revenues. Assuming a competitive market the auction process then selects the most efficient mix of capacity to meet the security requirements of the system.[126] To ensure potential new entrants can secure a capacity contract that has sufficient lead time to facilitate the financing of new generation, capacity auctions must be held anything up to 5 years in advance. The requirement for this lead time increases the exposure of generators to any regulatory decisions made within the interim period that affect their overall remuneration from the market.

The same source of regulatory risk exists under the current approach where the total capacity revenue (to be competed for in the market) is set by the regulatory

[124] Concentration within the generation sector by a state owned utility means that implementing an auction process for the I-SEM generates significant risk of undervaluing capacity. While the consumer may see benefits in the very short-term such a scenario will substantially increase costs for the consumer over the mid to long term through inappropriate exit. Inappropriate exit will further reduce competition in the generation sector and by extension will reduce competition in the retail sector

[125] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 222 on p.50

[126] We have already expressed significant concerns regarding the feasibility of implementation a competitive auction within the context of the I-SEM in sections 6.2.1 above.

authorities. However, the generators exposure to it is arguably less assuming the capacity price in the revenue calculation is updated on an annual basis and the calculation of that price is appropriately updated by the regulator to account for the decision. While Energia acknowledges there is a balance that needs to be struck in any CRM between regulatory risk and price certainty, we would emphasise the need for the SEM Committee to be acutely aware of the specific nature of the risks a CRM imposes on generators and be mindful of the need to adjust regulatory decision making timelines and processes accordingly. This is to avoid a substantial increase in the exposure of generators to regulatory risk under a quantity based CRM that could lead to increased costs to consumers either through inappropriate plant exit or the application of a regulatory risk premium on capacity valuations.[127]

### 6.2.5 Cross border participation and distortion of cross border trade

It is not immediately obvious that a quantity based CRM with a link to physical capacity will easily facilitate cross border participation. This is particularly the case under the proposed use of FTRs in the I-SEM because a generator in another jurisdiction cannot guarantee that it can achieve the required physical flow across the interconnector required to avoid any penalties under the scheme. It should also be noted that GB has not solved the issue of cross border participation for its quantity based CRM to date. Therefore there is no compelling evidence to suggest that a so called quantity based mechanism has significant benefits over a long-term price based scheme with regards to cross border participation. In fact, it should be noted that the current SEM mechanism already promotes cross border participation. Under a ‘quantity based’ mechanism cross border participation is further complicated by the lack of availability of interconnector rights aligning with the potential capacity product lead times on either the Moyle or East-West interconnectors[128].

With relation to the distortion of cross border trade, a quantity based CRM, similar to GB mechanism or Reliability Options (if linked to physical capacity), that facilitates cross border participation through PTRs has the potential to distort cross border trade. This is because a generator participating in a capacity mechanism outside its region may schedule a flow on an interconnector that is contrary to the energy price signal to avoid exposure to the penalty charges – e.g. if both electricity systems were under stress. Furthermore, as NERA note, the potential for abuse of market power in a quantity based CRM within the context of the I-SEM itself could distort cross border trade if capacity is incorrectly valued. This is because an incorrect valuation of capacity would change the incentives on generators within the energy market and therefore its dynamics.

[127] Given the recent seemingly arbitrary nature of regulatory decision making – e.g. the carbon levy, changes to rules around gas capacity and the selection of the I-SEM HLD - the perception of regulatory risk in the I-SEM is likely to be substantial. Also see April 2014 NERA report on this point.
[128] Indeed given the likelihood of full firmness of interconnector capacity in the forwards network code (https://www.entsoe.eu/major-projects/network-code-development/forward-capacity-allocation/Pages/default.aspx), interconnector owners are reluctant to sell capacity more than two years ahead given the risk of long term planned outages and their exposure of paying out the market spread for the duration.

"… [P]ure quantity based schemes may be more prone to abuse by dominant players – and might conceivably cause even more distortion of cross border flows. Experience in the United States shows that the price of capacity in a quantity based CRM is sensitive to generators withholding capacity (or increasing the supply of capacity and demand-side resources). The price of capacity in a pure price based schemes cannot be manipulated in this way and might cause less distortion of cross-border trade."[129]

Distortion of cross border trade is therefore not a problem that is exclusive to so-called long-term price based mechanisms and should not be unduly construed as a strong argument against them or in favour of so-called quantity based mechanisms.

### 6.2.6 Appropriate Exit Signals

The problem, to the extent that it exists, of uneconomic capacity remaining in the market is not one that can be resolved by the choice of CRM. To the extent that a the price paid for capacity under a long-term price base mechanism reduces appropriately relative to the amount of capacity available to the market – i.e. the scheme utilises a sloping demand curve - an appropriate exit signal is created. This is the case under the current capacity mechanism in the SEM. The exit signal can then be further reinforced through appropriate testing and penalties if required. The need for appropriate exit signals therefore should not be used as an argument against continuation of the current mechanism or for the introduction of a so called quantity based scheme in the I-SEM.

As NERA explain in their April 2014 report: "[i]n principle the problem of so-called 'zombie' capacity can occur in price or quantity based mechanisms, and has frequently been referred to in respect of the quantity-based ISO-NE market".

And as NERA further explain in their most recent report: "In both types of CRM [quantity based and price based], only those with the lowest cost capacity (existing or new) will remain in the market over the long-term. Both types of CRM will therefore encourage efficient exit – i.e. the exit of the capacity with the highest cost of remaining in operation"[130].

### 6.2.7 Conclusion

The current approach remains the most appropriate form of capacity mechanism for the I-SEM. Compared to quantity based scheme, within the context of I-SEM, the existing approach to CRM design will:

6. Reduce the risk of predatory or non-commercial pricing in the I-SEM capacity market;
7. Reduce volatility in the I-SEM capacity price;
8. Reduce regulatory risk;
9. Avoid inappropriate plant exit and entry cycles; and

[129] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 177 on p.39
[130] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 172 on p.38

10. Deliver cheaper security of supply for I-SEM consumers over the long-term.

## 6.3 *Critique of Reliability Options*

Energia has significant concerns regarding the choice of Reliability Options (ROs) as the preferred form of CRM for I-SEM and we strongly dispute the claim that this type of scheme is consistent with international best practice. ROs are essentially a form of financial option contract sold by a generator that will directly link the operation of the I-SEM energy market to the operation of the capacity market adding additional and unnecessary complication to the market arrangements. This causes a number of practical issues for the HLD that have not been given sufficient consideration and that are discussed in detail below.

### 6.3.1 Addressing the Missing Money Problem

Reliability options as specified in the DPP and IIA are purely financial. However, reliability options cannot replace the missing money from the energy market unless they are explicitly and effectively tied to physical capacity, as well as to the energy market. As NERA observe:

“We discussed this point in the memo dated 2 May 2014 and entitled “Reliability Options: Clarification Note”, which Energia duly forwarded to the RAs. In that memo, we explained that ROs would only offer additional revenue above the energy price if it was backed up by additional penalties for failing to provide capacity, as in the design currently being adopted in Great Britain (and in other countries’ schemes as well).”[131]

It is further corroborated by the academic literature cited by the RAs in the DPP and IIA.

“… [T]o support its particular version of Reliability Options, the SEM Committee quoted two academic papers in the DDP, Vazquez et al (2003) and Cramton and Stoft (2008).32 In practice, none of these authors support the position of the SEM Committee. On the contrary, these authors (and others) agree either explicitly or implicitly with the need for Reliability Options to be tied to physical capacity, as well as to the energy market … .“[132]

In fact, purely financial reliability options exist nowhere in the World as confirmed by Pablo Rodilla’s presentation (slide 9) at the 17 June industry forum in Dundalk. And even when tied to physical capacity reliability options do not necessarily work effectively. For example, Batlle et al (2014) identify the absence (or ineffectiveness) of additional penalties in the Colombian system as a potential constraint on achieving a reliable supply of generation.

The SEM Committee should note that the need for an effective explicit link to physical capacity changes reliability options into a form of CRM that is much more

[131] “I-SEM Draft Decision SEM-14-045: A Review” paragraph 139 on p.30
[132] “I-SEM Draft Decision SEM-14-045: A Review” paragraph 140 on p.30

closely aligned to the GB mechanism and therefore will re-introduce many of the issues (e.g. certification of capacity and additional penalties for non-delivery) identified for that option, thereby removing many of the benefits attributed to ROs (which seem to mostly be assumed to be purely financial) in the DPP and IIA.

"… the SEM Committee refers to ROs throughout the DDP as "market-based", implying that they avoid the regulatory decisions required by other CRMs. In practice, as shown above, Reliability Options need arrangements linking them to the delivery of capacity to ensure that ROs solve the missing money problem. The need for such regulatory arrangements undermines the SEM Committee's repeated claims that ROs are an entirely "market-based" solution to the missing money problem.

The failure to consider these arrangements in this phase means the SEM Committee has not carried out a complete appraisal of the different CRMs (even at a high level). Instead, the SEM Committee's representation of the CRMs is selective, with the key regulatory features of Reliability Options being given little emphasis relative to the regulatory features of other CRMs. This mis-representation of ROs biases the SEM Committee's choice of CRM and leaves the draft decision without any basis for asserting that ROs will address the missing money problem. As a result, the draft decision to select ROs as the preferred form of CRM is unsound."[133]

Energia therefore requests that the decision on the form of CRM is re-evaluated once sufficient detail is available on the form of reliability options being proposed for the I-SEM including their proposed reference price – see next section.

### 6.3.2 Selecting a reference price for Reliability Options

It is impossible to properly assess the impact of reliability options on the I-SEM without knowing the market price they will be referenced against. The choice of the reference price for reliability options will fundamentally change how they affect the overall coherence and efficiency of the HLD. Some of the issues that arise in relation to the selection of a reference price are detailed below.

#### 6.3.2.1 Potential in selecting a reference price for Reliability Options

The reference price for reliability options and the financial forward market must be the same to accommodate modifications to financial forward contracts and remove potential double exposure for generators.[134] If reliability options are referenced to the balancing market it therefore generates significant issues for the operation of the forward market because the requisite changes to forward contracts cannot be implemented. If reliability options are referenced to the DAM it undermines their ability to provide flexible capacity when it is actually required, in the balancing timeframe. Furthermore, if the DAM has an explicit price cap (currently set at €3,000/MWh in EUPHEMIA) and the balancing market does not, this opens up an

[133] "I-SEM Draft Decision SEM-14-045: A Review" paragraphs 150 and 151 on p.33-34

[134] Please note the additional complexity added to the forward contracting process due to reliability options. This is discussed in more detail later along with our concern that this additional complexity will further inhibit forward market liquidity.

arbitrage opportunity for generators whereby they have a capped liability in the DAM but an uncapped upside in the balancing market. Under a non-mandatory DAM, at times of obvious severe system stress, this could result in generators actively choosing to opt out of the DAM to participate in the balancing timeframe. If an explicit price cap is then required in the balancing market to remove this incentive, it indicates the inefficacy of the design – i.e. the inappropriateness of referencing reliability options to the DAM price. These issues are discussed in section 6.4 of the July NERA report.

#### 6.3.2.2 Capacity Scarcity is a Feature of the Balancing Market

Capacity scarcity is a feature of the balancing market (i.e. real time)[135] and not the DAM. Referencing ROs to the DAM, while required to ensure the proper functioning of the I-SEM forward market, undermines one of the primary functions of the mechanism; the flexible delivery of electrical energy at times of system stress.[136] This disconnection between the calling of ROs and real-time capacity scarcity is further exacerbated if the DAM is non-mandatory. This is because it substantially increases the potential for ROs to be inappropriately triggered (or not triggered) depending on the volume of offers versus bids submitted to the DAM, rather than the actual underlying physical capacity margin of the system. The appropriate reference price for ROs is therefore the balancing market and not the DAM. This is to ensure ROs are triggered as a result of capacity scarcity rather than trading anomalies in the DAM.

#### 6.3.2.3 Excessive Emphasis on Provision of Energy rather than Capacity

If ROs are referenced to the balancing market then Energia questions whether such an excessive weighting towards rewarding the flexible delivery of energy is appropriate. Flexibility can be incentivised and rewarded through other aspects of the HLD (e.g. the balancing mechanism and ancillary services) whereas capacity adequacy cannot. Furthermore, a generator can reflect its anticipated revenue from other sources in its capacity valuation under a quantity based mechanism therefore incentivising the efficient selection of appropriate capacity, assuming the absence of market power.[137] Proceeding with a CRM so heavily weighted towards rewarding the flexible delivery of energy however would risk unduly prejudicing the selection of capacity for I-SEM to the potential detriment of a fuel diverse and efficient system. For example, if reliability options were referenced to the balancing market this would then cause issues for generators with long start up times – e.g. coal units – which would have a negative impact on the diversity of the fuel mix in the I-SEM in the longer term with significant repercussions for system security.

[135] We note that the proposed HLD has the balancing market opening after the DAM closes although it remains unclear whether the TSO will take energy balancing actions prior to the IDM gate closure.

[136] Numerous examples could be constructed of ROs referenced to the DAM being triggered based on a perceived shortage that did not arise in real time or vice versa.

[137] Please note that it is the existence of market power, combined with the small size of the capacity market and the potential for substantial regulatory risk, that makes a quantity based CRM inappropriate in the I-SEM.

### 6.3.2.4 ROs Increase Exposure Scheduling Risk

Under the proposed HLD referencing ROs to the DAM would further increase the exposure of generators to scheduling risk. Given the concerns regarding scheduling risk discussed in detail in section 5.1 above, generators may have insufficient information available prior to DAM gate closure to enable them to formulate offers into the DAM that ensure that they receive the operating schedule they require to cover their exposure under ROs.[138] This is because anticipating a potential exposure under ROs may change a generators preferred balance between the level of price risk they are prepared to accept compared to the level of volume risk.[139] Energia would stress the significant difficulty an out of merit generator will have in predicting whether the RO strike price is likely to be reached in the DAM particularly if the DAM was non-mandatory. Such a generator would, however, be able to deliver electrical energy should it actually be required within the balancing timeframe – i.e. if the lack of offers to sell electricity in the DAM was indicative of a capacity shortage in real time.

The potential for increased exposure to scheduling risk under the CRM design will increase costs to consumers as generators will either seek to manage this risk by increasing the cost of ROs or by pricing their actual exposure to ROs into the balancing market. In the former scenario the cost of capacity is inflated by an underlying inefficiency in the market design. In the latter scenario the demand not matched through the DAM is effectively paying twice for capacity – i.e. the charge levied on consumers for the provision of ROs and via the balancing mechanism.

"ROs will only provide a tool for managing generators' risks if generators can expect to be generating the same volume as their ROs at peak times when the ROs are called and rebates must be paid. (Criterion (4)) The articles by Cramton and Stoft discuss how the capacity each generator can offer (CBID) should be adjusted for their observed or expected reliability. However, the use of Euphemia creates an additional source of scheduling risk, as discussed elsewhere in this report. Generators may be unable to ensure that they are generating at peak times, because they are unable to configure their offers to achieve the necessary pattern of output, and not because they are technically unable to provide capacity. (Criterion (9)) Such risks would unnecessarily increase the cost of generating (and hence prices to consumers) within the I-SEM with ROs as specified in the DDP."[140]

Scheduling risk could also present a barrier to entry into and ongoing participation in the I-SEM for smaller generators, DSUs and AGUs.

[138] As discussed in detail in section 5.1 above, a generator must balance potential price risk against potential volume risk in the DAM when formulating its offers. If a generator anticipates that the RO strike price will be reached in the DAM it may be willing to accept additional price risk in the DAM to reduce its volume risk and therefore potential exposure to its RO cash out. If a generator has insufficient information to anticipate that ROs will be called in the DAM it is unable to make this adjustment to its bidding strategy and may therefore be exposed to the difference between the DAM and strike price under the reliability option.

[139] See discussion of scheduling risk in section 5.1.

[140] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 185 on p.41

Therefore, to mitigate these risks, if reliability options are referenced to the DAM, a generator should only be obligated to make a difference payment under a reliability option if it is scheduled in the DAM.

### 6.3.3 Renewable Contribution to Capacity Adequacy

Reliability options devalue the significant contribution to capacity adequacy made by wind generation within the context of the I-SEM. It seems incongruous with prevailing renewable targets that the SEM Committee is implementing a capacity mechanism that, due to the nature of its penalty arrangements and their link to the predictable presence of generators in the energy market, makes it problematic for intermittent wind generation to participate and thereby receive remuneration for its acknowledged contribution to generation adequacy.[141] Proceeding with reliability options suggests an implicit assumption that wind generation does not contribute to capacity adequacy and therefore should not be paid the "missing money" from the energy market. Therefore, for the SEM Committee's logic to be consistent on this matter wind must be excluded from the calculation of the I-SEM capacity requirement under an RO based CRM.

### 6.3.4 Unnecessary Complexity for the I-SEM Forward Market

Given the liquidity issues in the current SEM forward market Energia would stress that careful consideration is required regarding the impact of ROs on the operation of the I-SEM forward market. Under the proposed HLD the exposure of generators to difference payments under a CfD contract would have to be capped at the strike price of its ROs. This adds additional unnecessary complexity into the forward contract process even under a single uniform market-wide RO strike price and becomes significantly more problematic if there are multiple strike prices in the market – e.g. RO strike prices set by generator technology types.

In the scenario where there are multiple strike prices, to the extent that a supplier entering into a CfD with a generator received a 'rebate' under ROs referenced to a strike price that was higher than the strike price of the ROs held by the contracting generator, the supplier would have price exposure under its contracted position. This is because at periods of extreme market pricing the payments from the generator under the CfD would be capped below the level required by the supplier based on the 'rebate' it accrues via ROs. As NERA observe:

"Setting multiple RO Strike Prices would reduce transparency and segment the CfD market (and would in any case greatly increase the complexity and subjectivity of regulatory decisions on design of the RO)."[142]

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[141] Wind's significant contribution to generation adequacy is reflected in EirGrid's assessment of the generation capacity standard. To the extent that reliability options as implemented in the I-SEM address "missing money" from the energy market wind is unable to recoup this missing money.
[142] "I-SEM Draft Decision SEM-14-045: A Review" paragraph 183 on p.41

Energia therefore recommends that if ROs are implemented in the I-SEM it is done with a single strike price indexed to the SRMC of the most expensive generator on the system.

### 6.3.5 Dampening of Market Signals for Demand Side Participation

The introduction of ROs will effectively dampen the signal for demand to reduce load at times of system stress by either flattening time of use tariffs or through the receipt of an RO 'rebate'. This seems contrary to the intention that the HLD should incentivise demand side response and participation in the market.

### 6.3.6 Issues with cross border participation and potential distortions of cross border trade

As discussed in section 6.3.1 there is a requirement to link reliability options to physical capacity to solve the "missing money" problem. As discussed in section 6.2.5, this introduces complications regarding cross border participation, particularly given the proposed use of FTRs under the HLD. Cross border participation is further complicated by the lack of availability of interconnector rights aligning with the potential capacity product lead times on either the Moyle or East-West interconnectors. Furthermore, if the strike price for reliability options is not indexed to the SRMC of the most expensive installed generator in the I-SEM this could lead to distortions in cross border trade – i.e. exports from the SEM at times of system stress. This is because the strike price of ROs could act like a cap on electricity prices as generators are likely to prefer to take the known exposure of under recover against their SRMC to the unknown and potentially significantly greater exposure of cash out under ROs. This is arguably more likely because of the increased exposure of generators to scheduling risk under the HLD, as discussed in section 5.1 above.

### 6.3.7 Increased Regulatory Risk due to Contractual Obligations

As discussed in section 6.2.4, the protracted time period between auctions and the commencement of capacity contracts required to facilitate participation by potential new entrants under quantity based schemes has the potential to significantly increase the exposure of generators to regulatory risk. If the financial obligations of a generator under reliability options cannot be terminated following a decision to close down or 'moth ball' generating assets (the requirement to do this may occur following a regulatory decision that undermines the economic viability of a power plant)[143] then a generating company may be forced to keep a loss making unit open until the end of its capacity contracting period.[144] Depending on the lead time set for reliability option contracts this could be anything up to five years. This is a significant potential risk for a generator and would be priced into capacity valuations in the auctions leading to higher prices for consumers. The counterfactual, however, has implications for

[143] For example, the removal of a short term daily gas capacity product or introduction of a levy such as the one introduced on carbon in the SEM, coupled with restrictions around bidding behaviour could precipitate this event.

[144] The same would be true of any quantity based scheme such as the GB mechanism if the generator could not terminate its contract and therefore exposure to the penalty mechanisms.

competition in the I-SEM capacity market. If a generator can terminate its reliability option contract then a large generation portfolio could use this flexibility to pursue a predatory pricing strategy by entering a plant they intend to close or 'moth ball' into capacity auctions to deflate capacity prices.

### 6.3.8 Increased Collateral Requirements and Cash Flow Issues

Given that reliability options are a form of forward contracting it is likely that generators will need to provide collateral to cover the risk of default. This could be a significant barrier to entry and ongoing participation for smaller generators, DSUs and AGUs. The cost of posting collateral will also need to be accounted for in a generators' valuation of capacity increasing costs for consumers.

Further consideration is required regarding the charging and payment mechanism for reliability option fees and the timing of 'rebates', to minimise their impact upon the cash flow of supply companies. To avoid undue increases in working capital (which would be reflected in increased costs to the consumer), the charging and payment mechanism for the reliability option fee would need to be seamlessly aligned with the timings of the charging and payment mechanism of the current SEM capacity mechanism. Furthermore, given the move to daily settlement in the energy market, rebates to supply companies need to either be paid prior to settlement of energy positions, or what seems more practical, netted off the invoices to supply companies.

### 6.3.9 Conclusions

Therefore implementing reliability options will have negative impacts on investment and security of supply and will result, over the long term (the appropriate time horizon to consider a capacity mechanism) in additional costs to I-SEM consumers. Energia would strongly emphasise that reliability options are not an appropriate CRM for the I-SEM for the following reasons:

1. They introduce further significant needless complexity into the HLD
2. They impose significant and unnecessary risk onto generators that will translate into higher costs for consumers
3. They unnecessarily conflate and exacerbate market power concerns in both the capacity market and energy market (as the RO penalty regime is linked to the energy market price);
4. They raise significant issues for the efficient functioning of the I-SEM regardless of the reference price that is chosen (see section 6.3.2 above);
5. They effectively exclude any payment of "missing money" to renewable generation due to their penalty regime being linked to payments in the energy market; and
6. They require a link to physical capacity to solve the "missing money" problem thereby making them subject to many of the issues identified with other forms of CRM (see section 6.3.1 above).

If the SEM Committee proceeds with implementing a quantity based CRM despite the strong arguments set out against such a decision in section 6.2 and 6.3 above, Energia strongly recommend that the chosen mechanism is closely aligned to the GB capacity mechanism rather than reliability options. This will:

1. Reduce superfluous complexity;
2. Minimise unnecessary risks of CRM participation for generators, decreasing costs for consumers;
3. More easily facilitate participation by small generators, DSUs and AGUs improving competition and promoting demand side participation in the I-SEM; and
4. More easily facilitate participation of wind, assisting delivery of renewable targets.

## 6.4 *Need for Transitionary Arrangements*

Energia would emphasise the need for transitionary arrangements in the I-SEM if the SEM Committee proceeds with a quantity based mechanism. Generators will need to accumulate substantial operational experience of their remuneration under I-SEM energy trading arrangements and the new DS3 system services regime to facilitate a reasonably accurate valuation of the provision of capacity. Combined with the required substantial lead time for capacity products required under quantity based mechanisms this means that it could be a considerable period of time before a capacity price could be set under a quantity based mechanism. Proceeding with a quantity based mechanism without allowing generators to acquire sufficient operational experience of new market arrangements is likely to result in inefficient capacity pricing and therefore additional costs for consumers. This is because when faced with an unknown but potentially significant commercial risk the natural tendency is to overcompensate for the risk.

To mitigate against this potential inefficiency in the valuation of capacity and the likely extensive gap between the end of the current SEM mechanism and the start of capacity products under the I-SEM mechanism, Energia strongly advises that the SEM Committee maintain the current SEM capacity mechanism for an appropriate transitional period taking into account the auction lead time and a 'bedding in' period for the I-SEM energy trading arrangements and the new DS3 system services regime. Compressing the timescale between the auction and the start of initial I-SEM capacity products under a quantity based mechanism would result in the inefficient valuation of capacity; exclude new entrants from participating; and require a full set of auction rules and market power mitigation measures to be in place by the end of 2015 which is completely unrealistic.

Maintaining the current arrangements for a number of years is therefore the most sensible and lower risk approach; it would not present a barrier to new entry; it would provide the necessary time to develop appropriate market power mitigation measures; and it would enable generators to gain sufficient operational experience of the new market arrangements (including DS3) to correctly value the provision of capacity, thus protecting I-SEM consumers.

**Summary of Energia's response to the Proposed Capacity Remuneration Mechanism**

- NERA note that the SEM Committee decision to implement a quantity based mechanism has been biased by a mischaracterisation of the typical attributes of price based mechanisms (such as an assumption that they cannot provide appropriate exit signals) and an incorrect understanding of the risk of double payments (the Double Payment Fallacy).
- This mischaracterisation has resulted in not enough attention being paid to fundamental aspects of the I-SEM market (such as its small size and the dominance of ESB) and the concerns these create regarding the potential abuse of market power, capacity price volatility and the establishment of an inappropriate cycle of entry and exit; all of which are to the detriment of security of supply and the I-SEM consumer.
- We note that a quantity based scheme (due to their auction mechanism) are particularly susceptible to market power manipulation and the risk of predatory pricing. This should be addressed by retaining a long term price based scheme with a sloping demand curve similar to the current SEM or, at the very least, by setting a price floor referenced to an administered BNE calculation for I-SEM capacity auctions.
- We note that a quantity based scheme (due to their auction mechanism) will produce highly volatile capacity prices in the I-SEM. This is a result of the small size of the All-Island market. We note that this will lead to the establishment of an inappropriate cycle of entry and exit under a quantity based scheme to the detriment of I-SEM consumers. This should be addressed by retaining a long term price based scheme with a sloping demand curve similar to the current SEM or, at the very least, by setting a price floor referenced to an administered BNE calculation for I-SEM capacity auctions.
- We also highlight the increased regulatory risk introduced by the long lead times of a quantity based mechanism and note that if a quantity based mechanism had been in place in the current SEM generators could not have anticipated arbitrary regulatory decision such as those taken on gas capacity bidding or the carbon levy.
- We note that appropriate exit signals can be delivered by a long-term price based mechanism with a sloping demand curve that adjusts the value of capacity in relation to the provision of capacity.
- We observe that a long term price based scheme with a sloping demand curve similar was deemed the appropriate CRM design for the SEM in 2007 and conclude that it remains the appropriate CRM design for the I-SEM – i.e. that it is necessary to maintain efficient long-term security of supply and to protect I-SEM consumers.
- We note that the introduction of a form of reliability options as the I-SEM CRM will introduce significant unnecessary complexity into the HLD (including into the energy forward market).
- We note that the introduction of a form of reliability options as the I-SEM CRM will impose significant and unnecessary additional commercial risk (including increased regulatory risk and amplified exposure to scheduling risk) onto generators that will directly translate into higher costs for consumers.
- We note that the introduction of a form of reliability options as the I-SEM CRM will unnecessarily conflate and exacerbate market power concerns in both the capacity market and energy market (as the RO penalty regime is linked to the energy market price).

- For the reasons discussed in section 6.3.2 above, we conclude that the introduction of a form of reliability options as the I-SEM CRM will raise significant issues for the efficient functioning of the I-SEM regardless of the reference price that is chosen (including adding additional unnecessary complexity to energy forward markets);
- We note that the introduction of a form of reliability options as the I-SEM CRM will effectively exclude any payment of “missing money” to renewable generation due to their penalty regime being linked to payments in the energy market.
- We note that reliability options require a link to physical capacity to solve the “missing money” problem, thereby making them subject to many of the issues identified with other forms of CRM (discussed in detail in section 6.3.1 above).
- For the reasons outlined above, we therefore conclude that implementing reliability options will have negative impacts on investment and security of supply and will result, over the long term (the appropriate time horizon to consider a capacity mechanism) in additional costs to I-SEM consumers.
- However if the SEM Committee decides to implement a quantity based mechanism, despite the objections set out above, we strongly emphasise that the GB model provides a more suitable starting point for the I-SEM, providing it is appropriately tailored to suit all-island market conditions and is accompanied by a transitional mechanism based on the current CPM.
- Proceeding with a quantity based mechanism without allowing generators to acquire sufficient operational experience of new market arrangements is likely to result in inefficient capacity pricing and therefore additional costs for consumers.
- Energia therefore strongly advises the SEM Committee to maintain the current SEM capacity mechanism for an appropriate transitional period taking into account the auction lead time and a ‘bedding in’ period for the I-SEM energy trading arrangements and the new DS3 system services regime. Compressing the timescale between the auction and the start of initial I-SEM capacity products under a quantity based mechanism would result in the inefficient valuation of capacity; exclude new entrants from participating; and require a full set of auction rules and market power mitigation measures to be in place by the end of 2015 which is completely unrealistic.

# 7 Concluding Messages

- **The proposed I-SEM design** (in terms of its energy trading arrangements and capacity remuneration mechanism) **represents an unjustified and undesirable regulatory U-turn** in relation to fundamental consumer concerns pertaining to the All-Island market – e.g. promotion of competition and market power mitigation.
- We would stress the **unnecessary complexity of the HLD** and the barriers this will place upon new entry and external investment; particularly in a small market such as the I-SEM. The SEM Committee should also note that any additional risks they place on generators will manifest themselves as additional costs to I-SEM consumers in the long term either through reduced efficiency of the All-Island market or inappropriate generator exit.
- Due to concerns about the quality of the documents and potentially flawed understanding exhibited within them **Viridian commissioned NERA to evaluate the soundness of the HLD draft decision and the quality of the impact assessment** which informed it. NERA conclude as follows:

  *"We found many problems in the quality of the appraisal used to justify the SEM Committee's choice of option 3 and Reliability Options. In particular, we found areas where the appraisal is subjective, selective and biased, with the effect that the discussions are prejudicial and do not provide basis for selecting an electricity market design, putting the Decision at risk of legal challenge. We conclude that the SEM Committee's decision is unsound and that market participants cannot have confidence that the SEM Committee has reached the right decision on high level design for the I-SEM"* (Executive Summary, page iii)
- **NERA would be willing to discuss their report with the RAs or government departments** if that would be helpful, and we would be willing to exclude ourselves from such discussions.
- Energia recommends that the **SEM Committee should not move forward with a final HLD decision that is not supported by robust evidence** or without having considered all its implications for I-SEM consumers relative to viable alternatives.
- Given the findings and conclusions of the NERA report **we urge a third party review** of the recommendations provided to the SEM Committee and the supporting impact assessment that will inform the HLD decision and also that a 'Quality Assurance' role for an independent third party be included in the I-SEM project going forward.
- **We maintain that a HLD which allows physical trading and self-scheduling coupled with the existing capacity mechanism design represents the most appropriate HLD for the I-SEM** as it would build on the successful areas of the current SEM (i.e. the security of supply delivered by the current CRM) and improve on areas that the SEM is currently failing (forward market liquidity and greater efficiency in interconnector flows).
- **Both the energy market and CRM proposed are unnecessarily complex** compared to a self-scheduling (but centrally traded) market and the existing approach to capacity remuneration. Complex markets favour large participants, are difficult to regulate, deter investors and lead to poor outcomes for consumers.
- Recognition of the **forward market liquidity problem** in the current market is welcome. However the proposed decision for trading energy represents a missed opportunity to bring greater competition into the forward market. This implies a greater reliance on regulatory measures to promote forward market liquidity and this should be prioritised in the detailed design phase of I-SEM. Forward contracting would normally occur between 6 and 24 months in advance of real time with some

retail customers wishing to contract 3 years ahead, thus it is important to get this component of the market working early otherwise there will be a hiatus of forward liquidity to the customers' detriment coinciding with the start of the new market.

- Exclusive use of Euphemia for scheduling the DAM results in substantial subjectivity in offers and presents a significant advantage to large portfolio players through **information asymmetry and scheduling risk** and this concern is **substantiated in the Baringa Report**.
- **Non-mandatory participation in the DAM** will increase scheduling risk and split liquidity in the DAM. This could have a significant negative impact on forward market liquidity in the absence of physical forward trading and self-scheduling, undermining retail competition. Therefore Energia would stress that any move towards a non-mandatory DAM under the proposed HLD necessitates the introduction of a physical contract market and self-scheduling to mitigate against this risk.
- We welcome the decision to test the suitability of exclusively using Euphemia for scheduling given its unprecedented application in this way. To be meaningful, **Euphemia testing** must be: rigorous, inclusive and transparent; completed prior to final HLD decision; and published (including both inputs and outputs of the testing) prior to final decision.
- The proposed ISEM HLD **invalidates the previous SEM Committee decision to allow horizontal re-integration** of ESB which was predicated upon the existence of existing BCoP and SRMC bidding rules (as advised by CEPA). A significant increase in the level of directed forward contracts (or the equivalent) is therefore required.
- **Market power is a major concern in any quantity based CRM**. A capacity price floor based on the current BNE calculation is needed to avoid predatory pricing or non-commercial objectives to keep uneconomic plant open in capacity auctions.
- A capacity price floor is also needed to prevent **inappropriate cycles of entry and exit** that would result from the small size of the all island market.
- Reliability options as proposed will not address the **missing money problem** – an appropriate link to physical capacity is needed which will require further regulatory arrangements. With an appropriate link to physical capacity reliability options lose their supposed comparative advantage over other CRM options in facilitating **cross border participation**.
- If reliability options are referenced against the day-ahead price they will **amplify the scheduling risk** in the DAM synonymous with the proposed I-SEM energy trading arrangements, as discussed in the Baringa report. To mitigate this risk, a call on the reliability option should only be made when the generator is scheduled in the relevant reference market.
- Reliability options are **not amenable to wind** which is inconceivable in a market with 40% renewable targets. This should be addressed with reference to concerns and proposals put forward by IWEA which we support. If this proposal is not adopted, it is imperative that consistency is shown and wind's contribution to generation adequacy is removed from the capacity requirement calculation.
- **Other adverse effects of reliability options** have not been considered. For example they add unnecessary complexity to forward wholesale contracting and the retail market; dampen market signals for demand side participation; increase the burden of working capital and collateral requirements on market participants; and potentially result in flows of energy from the I-SEM to GB at times of system stress.
- This existing approach (labelled a long term price based mechanism by the RAs) is the correct choice for the I-SEM, however if the SEM Committee continues to favour

a so-called quantity based mechanism, **the GB model** provides a more suitable starting point for the HLD providing it is **appropriately tailored to suit all-island market conditions** (i.e. it would require a price floor based on an administered BNE calculation) and is accompanied by an appropriate transition mechanism.

- We stress the importance of **appropriate regulatory mechanisms** to deal with the complications and distortions that the all-island market presents. This market (both in respect of energy trading and capacity remuneration) cannot be relied upon to work efficiently and competitively in the absence of regulatory management, irrespective of developments or requirements at a European level.
- We would stress the need for market participants to be able to compete economically against Eirgrid to deliver an aggregation service for renewable generators. Given the potential for Eirgrid to monopolise the delivery of this service careful consideration needs to be given to the set-up of the **aggregator of last resort** in the I-SEM to ensure there is sufficient scope for effective competition to emerge for the delivery of this service, reducing costs and maximise benefits for renewable generation.
- Minimising **collateral requirements** whilst protecting generator revenues must be given high priority in the detailed design phase with the optimum outcome only likely to come through genuine consultation with industry experts.
- On important **points of process**: the industry urgently needs a revised project plan. It is in the interests of consumers, participants, regulators and governments to get the market design and testing right. When viewed in the medium and long term, this objective must override objectives to meet short term deadlines and project milestones. If the previous project plan published in February 2013 was realistic, the new plan must change the implementation date by 5 months to reflect the delays experienced to date and the importance and magnitude of the work that remains to be done.

# 8 Annex 1 – Independent Expert Reports and Relevant SEM Committee Decision

The following non-confidential reports accompany and support this response (they are submitted as separate documents prefaced by their Annex reference):

Annex A.1.1: NERA Report: “I-SEM Draft Decision SEM-14-045: A Review”, Report for Viridian, July 2014

Annex A.1.2: Baringa Report: “Scheduling risk under the proposed I-SEM High Level Design: An issues paper”, Multi-Client Report for Viridian, Tynagh, AES and Bord Gais Energy, July 2014

Annex A.1.3: CEPA (2010): “Market Power and Liquidity in SEM – A report for CER and the Utility Regulator

Annex A.1.4: SEM Market Power and Liquidity- A SEM Committee Decision SEM-12-004, February 2012

Annex A.1.5: NERA Clarification Memo on Reliability Options, May 2014

NERA
ECONOMIC CONSULTING

# I-SEM Draft Decision SEM-14-045: A Review

Prepared for Viridian

25 July 2014

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# Contents

# Executive Summary

Viridian has asked us to comment on the SEM Committee's Draft Decision Paper (DDP) and the associated Initial Impact Assessment (IIA) on a High Level Design for the new "Integrated Single Electricity Market" (I-SEM).

Viridian asked us specifically to assess the soundness of the proposed decision on the High Level Design for the I-SEM. Viridian also asked us to identify any potential areas of concern over the supporting rationale provided by the SEM Committee for its draft decision and to identify areas of the market design that require significant further clarification during the detailed design phase. Our instructions cover the "Options" for trading energy as well as the "Capacity Remuneration Mechanisms" (CRMs).

In reviewing the DDP and IIA, we found problems in the quality of argumentation, the application of appraisal criteria and the descriptive evidence used to support the appraisal. The SEM Committee's appraisal is, as a result, subjective, selective and biased. It does not provide a proper basis for selecting an electricity market design and no-one can have any confidence that the SEM Committee has reached the right decision on a High Level Design for the I-SEM. We conclude that the SEM Committee's decision is unsound. We have indicated how these problems may be addressed in the final decision.

## Quality of Argumentation

We found that our task of reviewing the DDP and the IIA was hampered by the poor quality of the argumentation in those documents.

The appraisal criteria adopted by the SEM Committee are defined in vague terms, interpreted subjectively and applied selectively. On occasion, the appraisal seems to turn on unstated criteria, such as "liquidity". We have therefore proposed a set of more practical appraisal criteria. Arguments used in relation to one possible design (i.e. to one Option or one CRM) were not applied equally to other possible designs, causing the evaluation to be incomplete and selective. We have pointed out where this problem arises. The categorisation of different schemes (particularly the CRMs) contains errors that bias the eventual selection. We have provided correct information where it might affect the appraisal.

## Focus on Trade Rather than Dispatch

The most serious problem with the SEM Committee's appraisal of Options and CRMs lies in a mis-specification of the proposed reform's overall objective.

Discussion of the new electricity market, the I-SEM, has been prompted by the desire to promote "market coupling", i.e. to improve the SEM's integration with the British electricity market. Market coupling is an initiative running throughout the EU to facilitate cross-border trade in electricity. Its objective is to increase the efficiency with which capacity, including both supply-side and demand-side resources, is dispatched at a European level, in order to reduce costs and increase efficiency.

The authors of the DDP and the IIA appear to have lost sight of this objective. The appraisal of the Options and CRMs gives very little attention to their effect on the efficiency of the intra-day and real-time process of *dispatch* or to actual outcomes for generation and consumption. Instead, it focuses on promoting *trade* within the day-ahead institutions used for market coupling. In other words, the DDP and IIA give undue weight to the prospects for a *derivative* product (trading in day-ahead electricity contracts), instead of considering the impact of proposals on the *underlying commodity* (electricity generated and consumed).

This focus on trading rather than dispatch distorts the appraisal of market designs and prejudices the SEM Committee's selection of a preferred Option. It is possible to remedy this deficiency in the final decision and impact assessment as we explain.

### Appraisal of Options for Energy Trading

The "Qualitative Appraisal" set out in the IIA provides no objective or balanced support for the SEM Committee's draft decision. Gaps in the definition of the chosen Option and its potential effects are significant enough to affect the SEM Committee's appraisal. More analysis is required to ensure that the chosen Option meets the criteria of efficient market design. In the meantime, the SEM Committee's appraisal is selective and prejudiced, rendering its decision unreliable.

The chosen Option relies on a trading algorithm, Euphemia. The SEM Committee assumes that it will produce an efficient pattern of output in the day-ahead market, but it may not, given the lack of detail on intra-day and real-time institutions. These institutions may allow the TSO to restore an efficient pattern of generation, but inefficiency in the day-ahead market will raise costs and prices to consumers. Moreover, the SEM Committee has not addressed the problem of volume/scheduling risk. The discussion of interconnectors contains several errors and does not fully consider alternative contract forms. In relation to the liquidity of forward markets, the assessment does not compare the Options on a level playing field, but adopts varying criteria which favour some Options over others on an *ad hoc* basis.

The appraisal of the proposed Options is therefore incomplete, subjective and prejudiced. As a result, the conclusions reached in the DDP must be considered unsound.

### Appraisal of Capacity Remuneration Mechanisms

The appraisal of CRMs suffers from many of the same flaws as the appraisal of energy trading options. The problems begin with the creation of a false dichotomy between "price based" and "quantity based" schemes. Most relevant examples include a demand curve – an explicit trade-off between price and quantity – and so do not fall within either category. (The same trade-off is implicit in other schemes.) The advantages and disadvantages that the appraisal assigns to each CRM according to whether it is "price based" or "quantity based" are therefore spurious.

When deciding in favour of Reliability Options, the SEM Committee repeatedly describes them as "market based", and marks down other schemes for requiring regulatory interventions. This approach overlooks practical examples and academic literature on the design of Reliability Options. Experience and theory both indicate that the payments to providers of capacity under Reliability Options should be linked to the provision of physical capacity (not just energy). Reliability Options therefore require regulatory intervention, to decide what capacity is provided by each resource and how to penalise resources that fail to deliver it. The SEM Committee defers discussion of such topics until the detailed design phase. However, it cannot properly compare Reliability Options with other CRMs in the high level design phase without taking these requirements into account.

The appraisal of CRMs is therefore incomplete, because the SEM Committee left out significant details from the proposed design of the Reliability Options. We also found the appraisal to be selective, because it overlooks possible adverse effects of the proposed scheme. In any case, the overall appraisal was biased by the use of criteria that varied from case to case, preventing like-for-like evaluation of the designs. Due to these flaws in its appraisal, the SEM Committee's choice of one particular CRM is not soundly based.

### Consideration of Market Power Mitigation

The consideration of measures to mitigate market power is equally selective. The SEM Committee has chosen Option 3, even though it will make the BCOP unworkable. It does not offer any alternative measures. This difficulty ought to have counted against Option 3, relative to Options 2 and 4, but the DDP simply defers the problem to the detailed design stage. Market power remains a problem, so any completely specified Option would include alternatives to the BCOP, such as an increase in the volume of directed contracts.

In relation to CRMs, the SEM Committee adopts different views in the DDP from those expressed in the IIA. The DDP repeatedly describes Reliability Options as "market-based" and implies that the process of awarding and managing them will be solved by transparent auctions with little need for regulatory intervention. The IIA, on the other hand, notes that conduct of an auction will require major regulatory intervention to mitigate market power. These conflicting approaches betray a fundamental confusion about the implications of Reliability Options for competition.

Overall, the SEM Committee's approach to the mitigation of market power is subjective and prejudicial. It is neither evidence-based nor a sound basis for regulatory decisions.

### Consequences for the Consumer

The choice of electricity market design has long term implications for consumers. Inefficiency and scheduling risk in the Day Ahead Market will raise costs and prices of electricity, even if the TSO can restore an efficient pattern of generation through intra-day and real-time trading. Incompletely specified CRMs will leave consumers exposed to the risk of under-investment in capacity. Given the long term nature of these implications, it would be undesirable to commit to a High Level Design before considering all its effects.

### Conclusions

We found many problems in the quality of the appraisal used to justify the SEM Committee's choice of Option 3 and Reliability Options. In particular, we found areas where the appraisal is subjective, selective and biased, with the effect that the discussions are prejudicial and do not provide a proper basis for selecting an electricity market design, putting the Decision at risk of legal challenge. We conclude that the SEM Committee's decision is unsound and that market participants cannot be confident that the SEM Committee has reached the right decision on a High Level Design for the I-SEM.

# 1. Introduction

1. Viridian has asked us to comment on the Draft Decision Paper (DDP) and the associated Initial Impact Assessment (IIA) issued by the SEM Committee on 9 June 2014 on the subject of the High Level Design for the new "Integrated Single Electricity Market" (I-SEM).[1]

2. Viridian asked us specifically to assess the soundness of the proposed decision on the High Level Design for the whole of the I-SEM, comprising both energy trading arrangements ("Options") and the Capacity Remuneration Mechanism (CRM). Viridian also asked us to identify any potential areas of concern over the supporting rationale provided by the SEM Committee for its draft decision on the High Level Design and to identify areas of the market design that require significant further clarification during the detailed design phase.

3. Rather than provide a line-by-line response to the SEM Committee's documents, we comment below on the quality of the arguments used in the DDP and IIA and on the SEM Committee's general approach to appraisal. We have taken this approach because we found many of the arguments in the documents to be poorly drafted, as explained in chapter2, for reasons that affect the documents as a whole, namely:

   - the Options and CRMs set out in the DDP and IIA are incomplete, with the result that it is not possible to appraise or compare them rationally and objectively. The DDP is intended to meet the requirements of the EU Target Model, which are dominated by a desire to facilitate cross-border trading, but that has led to the neglect of other – potentially more important – aspects of market design;
   - the DDP and the IIA apply design criteria in a selective and subjective manner, using vaguely expressed arguments that are sometimes prejudiced in favour of one particular Option (i.e. Option 3) or on particular CRM (i.e. a form of "Reliability Option").

4. In section 2.2, we clarify how these deficiencies could be remedied in the final decision. In chapters 3 and 4, we describe the problems with the draft decision, using examples from the documents themselves. These problems imply that the conclusions reached in the draft decision are not robust or soundly based. We provide more detailed comments on the arguments used in the DDP and the IIA in chapters 5 (Energy Market Arrangements), 6 (Capacity Remuneration Mechanism) and 7 (Market Power Mitigation), and in related appendices. Chapter 8 collects together all our conclusions.

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[1] SEM Committee (2014a), Integrated Single Electricity Market (I-SEM): High Level Design for Ireland and Northern Ireland from 2016: Draft Decision Paper, SEM-14-045, 9 June 2014 ("DDP"); and SEM Committee (2014b), Integrated Single Electricity Market (I-SEM): High Level Design for Ireland and Northern Ireland from 2016: Draft Decision on HLD for I-SEM: Initial Impact Assessment, SEM-14-046, June 2014 ("IIA").

## 2. Quality of Argumentation

5. The DDP states early on that "The SEM Committee is committed to evidence based decision making".[2] We applaud this sentiment, as regulatory decisions have long term implications for investment, for costs and for the prices paid by consumers. As long as the regulatory process is open to the submission of evidence by all interested parties, and such submissions are subject to scrutiny and challenge by others, regulators will have the best available evidence to hand. Making decisions based on evidence then minimises the potential for actions that are subjective, arbitrary or politically-motivated and hence not in consumers' interests.

6. In the current context, we expected to see an Initial Impact Assessment which provided a complete (if high level) description of each alternative electricity market design, and which applied a fixed set of appraisal criteria to each design, as neutrally and objectively as possible, to identify which design best meets consumers' needs. Such an IIA would have provided robust support for an "evidence based decision". The reality has proven to be disappointing. The lack of detailed reasoning places an unnecessary obstacle in the path of external scrutiny through an analytical review of the evidence.

### 2.1. Problems with the SEM Committee's Current Approach

7. The approach adopted by the SEM Committee in the DDP and the IIA creates a number of problems for external scrutiny.

8. First, the various possible designs for energy trading arrangements ("Options") and CRMs are not completely specified, or else different designs are specified in terms that overlap and prevent proper comparisons.

- The descriptions of Options for energy trading focus on short-term markets (and day-ahead markets in particular), but neglect many of the real-time institutions (balancing and imbalance pricing). These omissions make it impossible to appraise the impact of each Option on actual outputs, demand, pricing and the efficiency of outcomes.
- The description of CRMs makes a false distinction between "price based" and "quantity based" schemes, since in practice many schemes involve a trade-off between price and quantity – either explicitly (a "demand curve") or implicitly (through occasional revisions to scheme parameters). The description of Reliability Options (the favoured form of CRM) varies between a narrow definition (which excludes CRMs that are called Reliability Options in other countries) and a broad definition (which includes CRMs that would also count as "price based" or "quantity based").

9. These incomplete or variable definitions of different designs make it difficult to distinguish between the merits of different schemes. They also allow those carrying out the appraisal to pick and choose what (positive and/or negative) characteristics to assign to each market design. The result is a highly subjective and prejudicial review of each of the designs, which

[2] DDP, page 4.

appears to be aimed at justifying the selection of Option 3 and Reliability Options, instead of identifying the market design best suited to the I-SEM.

10. Second, the appraisal criteria used in the IIA and reflected in the DDP are defined in terms that can only be evaluated subjectively. The IIA then applies them selectively, or in conjunction with further unstated criteria, so that the market designs are not appraised on a level playing field. The result is that the SEM Committee's appraisal method gives every appearance of being biased in favour of a prior decision to select Option 3 and Reliability Options.

11. Third, some of the arguments set out in the IIA and DDP are demonstrably incorrect or non-sequiturs. For instance, the IIA considers the point that the auction price for Reliability Options will not cover the "missing money" if it is not backed up by rules on the physical definition of capacity and penalties for under-performance. It responds that this problem might arise if the RO market were purely voluntary, but will not arise "if the purchase of reliability options to cover total system requirements is mandatory".[3] We found this response rather surprising, since there is no basis in observation or analysis for such an assertion. We are therefore not convinced that the SEM Committee's impact assessment has been carried out thoroughly, taking account of the academic literature on this topic. (See section 6.1 below.)

12. It is difficult for third parties to engage with an appraisal that is subjective, selective and seemingly biased, and applied to market designs that are incompletely defined. External observers cannot know precisely what factors influenced the draft decision, or what further evidence would affect the final decision. All that can be concluded is that the draft decision is not "evidence based" in any proper sense, and is not objective, sound or reliable.

## 2.2. Requirements for the Next Stage

13. The next stage in the regulatory process is, technically, the production of a final decision. In that stage, any properly constituted Final Impact Assessment would have the following characteristics:

- Detailed descriptions of each market design which clearly identify (1) all the features that determine real world outcomes, and (2) all the features that distinguish one design from another;
- Appraisal criteria that are well defined and capable of objective measurement whenever possible;
- An appraisal process that applies the criteria equally to each market design (to the exclusion of other criteria);
- A neutral or even-handed evaluation of the market designs, covering all the appraisal criteria and noting any subjective or "qualitative" evaluations where they arise;

[3] IIA, paragraphs 7.5.26-27.

- A clear statement of the decision and the reasons for reaching it, drawn directly from the evaluation of market designs.

14. To produce a robust decision, the SEM Committee would have to meet all these requirements by the time of a final decision. We are conscious of the deadline for this decision, and our comments below are intended to fit with the proposed decision process. Should it not prove possible to resolve the outstanding difficulties in time, the SEM Committee would have either to postpone the final decision, or else to recognise that its decision is not robust and cannot be binding on the precise form of the I-SEM. Instead, its final decision would only be able to (1) recommend a market design as a starting point for further investigation, (2) list the matters to be investigated in detail, and (3) define the criteria for changing or adjusting the market design in the light of these investigations.

15. Equally importantly, the SEM Committee would need to adopt (and publicise) a procedure that allowed third parties to submit technical advice and to scrutinise all the work on a detailed design. The impact of market arrangements depends crucially on the details of their design and such scrutiny will be important to ensuring an efficient design for the SEM. The SEM Committee will in any case need to set up a procedure whereby the market designers and/or third parties can refer for adjudication (1) decisions to change (or not to change) the market design and (2) disputes over the detailed specification.

## 2.3. Conclusion

16. The arguments set out in the IIA are of very poor quality and do not support the decision process set out in the DDP. The descriptions of market designs are incomplete and not completely fixed or distinct, the appraisal is highly selective and subjective, and incorrect arguments are asserted without the support of observation or analysis.

17. We conclude that no-one can have any confidence that the SEM Committee has reached the right decision on High Level Design for the I-SEM.

18. In the following chapters, we identify the main deficiencies in the analysis produced so far and provide material that would help the SEM Committee reach a more soundly based decision.

# 3. Neglect of Real-Time Arrangements

19. We reviewed the sections in the DDP and the IIA that discuss energy market arrangements. In doing so, we identified a general flaw in the SEM Committee's approach that devalues the resulting conclusions.

20. The descriptions of each Option focus mainly on certain aspects of energy trading. This focus on trading seems to derive from the need for "market coupling" - primarily day-ahead – under the EU Target Model for the pan-European electricity market. Owing to this focus on day-ahead trading, the descriptions of each Option neglect the real-time arrangements for short-term trading and despatch that determine the final pattern of output and demand. This omission has serious implications for the appraisal of the Options and undermines confidence in the SEM Committee's conclusions.

21. In addition, the draft decision is based on an incomplete description of each Option and therefore of its impact on efficiency and security of supply. The lack of completely specified Options makes any appraisal difficult, if not impossible. In the context of the DDP, it means that the SEM Committee's appraisal of the Options does not consider all the relevant information and that its selection of Option 3 is not soundly based.

## 3.1. EU Target Model – Key Elements

22. The EU Target Model lies behind the SEM Committee's current proposal to change the way electricity is traded in the All-Island electricity market. In practice, it imposes relatively few requirements on the design of the electricity market itself, but does set out some requirements for cross-border trade, which the SEM does not meet at present.

23. The EU Target Model is set out most clearly in guidelines issued by ACER, particularly the *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity* ("CACM Guidelines") issued in 2011[4] and the *Framework Guidelines on Electricity Balancing* ("Balancing Guidelines") issued in September 2012.[5] Together, these and other guidelines set out the context for the current reform of the SEM. The key elements of these guidelines for the SEM Committee's work on a new High Level Design are as follows:

- **Market Coupling:** cross-border transmission capacity must be made available at the day-ahead stage all across Europe "implicitly" through trades arranged on power exchanges, rather than being explicitly auctioned.
- **Cross-Border Transmission Contracts:** to allow cross-border risk hedging, TSOs must auction off Financial Transmission Rights (FTRs) or Physical Transmission Rights (PTRs) to interconnector capacity. PTRs must be subject to Use-It-Or-Sell-It (UIOSI) provisions, making them similar in effect to FTRs.

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4 ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011.

5 ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012.

- **Gate Closure:** The CACM Guidelines provide for an intra-day market that enables market participants to trade energy as close to real-time as possible, through implicit auctions (trades on power exchanges that bundle together energy and any necessary cross-border transmission capacity) where feasible.
- **Balancing by TSOs:** TSOs in neighbouring countries must collaborate to pursue operational security, overall social welfare and efficiency: (1) by fostering competition, non-discrimination and transparency in balancing markets; (2) by facilitating the participation of demand response and renewable sources of energy; and (3) by promoting cross-border balancing exchanges.[6] More specifically, the Balancing Guidelines require TSOs to collaborate on achieving an efficient (i.e. least-cost) joint despatch across all systems,[7] which will require the TSOs to exploit all potential gains from trade (i.e. all opportunities for optimisation).

24. We set out more detail on these requirements in Appendix A.

25. The RAs have focused on day-ahead market coupling, with intra-day market coupling to follow in due course. According to the RAs,[8] day-ahead market coupling requires each electricity market to adopt the pan-European system – a single price-coupling algorithm ("Euphemia") that is approved by ENTSO-E; in addition, the RAs maintain that each TSO must submit all available cross border capacity to the operator of the cross-border market at the day-ahead stage. From our review of ACER's guidelines, it is not entirely clear how the RAs reached these conclusions. However, they seem to have guided the SEM Committee's appraisal of the various future "Options" for energy trading in the I-SEM. We would therefore expect the SEM Committee to explain the source of these conclusions in the Final Decision.

26. In any case, the desire to incorporate the I-SEM into the pan-European system has led to the SEM Committee focusing on day-ahead trading, rather than the actual outcomes for output and demand, as discussed below.

## 3.2. The Focus on Day-Ahead Trading

27. The appraisal set out in the DDP and backed up by the IIA focuses heavily on the design and role of the Day-Ahead Market (DAM), due to the emphasis on cross-border day-ahead trading in the EU Target Model. This focus on day-ahead trading has led the SEM Committee to neglect other aspects of electricity market design. The DDP and the IIA omit

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6 ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, section 2.1, page 12.

7 "TSOs are responsible for organising balancing markets and shall strive for their integration, keeping the system in balance in the most efficient manner and following the general objectives defined in Section 2.1 of these Framework Guidelines. To do so, they shall work with each other in close cooperation and coordinate their activities as much as necessary.…the Network Code on Electricity Balancing shall define that exchanges of balancing energy are to be based on a TSO-TSO model with common merit order list. In this model, TSOs share their balancing resources and optimise their activation in order to minimise the cost of balancing..." ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, sections 2.1 and 3.3.2, pages 12 and 17.

8 SEM Committee (2013), *Implementation of the European Target Model for the Single Electricity Market – Next Steps Decision Paper*, SEM/13/009, 15 February 2013, p18.

detailed descriptions of real-time market institutions, specifically: real-time despatch processes and *ex post* imbalance pricing. These real-time institutions play an important role in determining actual outcomes for output and demand, and hence for prices and investment. The design, role and impact of intra-day markets is also largely neglected in the DDP and IIA. Decisions on these institutions are left for the detailed design stage. Unfortunately, these omissions constrain and bias the SEM Committee's evaluation of Options for the I-SEM.

28. The institutions operating in real time (i.e. despatch and imbalance pricing) define how the I-SEM will organise and put a price on the "*underlying commodity*" – i.e. electricity generated and consumed. The intra-day and balancing markets provide the means by which market participants and the TSO react to changing circumstances, correcting any forecasting errors made at the day-ahead stage. All these aspects of the electricity market are crucial for achieving security of supply and efficiency in generation – both of which are important principles of electricity market design and criteria for appraising the Options. However, the DDP and IIA give very little attention to these crucial matters. Instead, they focus on the need for day-ahead trading, which is merely a market for *derivatives* of the underlying commodity.

29. This focus on derivatives, and the lack of attention to the underlying commodity, have distorted the SEM Committee's appraisal of the Options. The Options themselves are incompletely specified, and the SEM Committee reaches conclusions, based on considering the day-ahead market, that might be untrue or invalid if the SEM Committee had considered the system as a whole. In this chapter, we explain and illustrate these problems with the DDP and IIA. We show how the decision to select Option 3 is biased because it is not based on a full understanding of each Option's features or implications.

## 3.3. Incompleteness of the Market Designs

30. It is impossible to evaluate the performance of any Option without considering the real time institutions and their impact on the underlying commodity, in terms of security of supply and the efficiency of output, demand, pricing and investment in the electricity sector. The appraisal in the DDP and IIA rests on hidden assumptions about these other institutions. However, these hidden assumptions create inconsistencies within the appraisal of each Option and a bias in the comparisons between Options. We illustrate these inconsistencies and biases with two examples: (A) an example taken from the discussion of interconnectors; and (B) an example showing the effect of emphasising liquidity of markets rather than efficiency of actual outcomes.

### 3.3.1. Example (A): interconnector outcomes

31. The problem, caused by focusing on day-ahead trading, is well illustrated by the analysis of interconnector flows set out in section 5.4 of the IIA. That section contains a long discussion of the costs associated with inefficient use of interconnectors. It states the SEM Committee's view that Option 3 will increase "overall efficiency across both markets" (i.e. I-SEM and GB), because it integrates interconnectors into the Day-Ahead Market.[9] That reasoning is incorrect.

[9] IIA, paragraph 5.4.40.

32. Paragraph 6.3.44 of the DDP acknowledges that day-ahead trading over interconnectors is based on a forecast of the actual conditions that will apply on the following day. Trades arranged in the day-ahead market may therefore flow in the "wrong" direction, i.e. from a high-priced market to a low-priced market, if conditions change within the day. Efficient use of the interconnector does not therefore depend on the outcome of day-ahead trading, but rather on the mechanism for adjusting flows within each day.

33. The EU Target Model requires TSOs to collaborate on efficient cross-border balancing in real time. (See section 3.1 above.) Section 5.4 of the IIA examines the difference in cost between:

- efficient day-ahead trading (i.e. full use of day-ahead arbitrage opportunities between the I-SEM and Great Britain); and
- efficient use of interconnector capacity in real time (i.e. the actual pattern of output resulting from efficient despatch).

It finds that efficient intra-day adjustment of flows over interconnectors would produce cost savings with a net present value running into hundreds of millions of Euros.[10] These cost savings depend on the arrangements for adjusting interconnector flows *after* the day-ahead stage, not on the existence of a Day-Ahead Market. Such intra-day adjustments might be arranged (1) through renominations of actual flows by market participants, (2) through intra-day cross-border trades, or (3) through inter-TSO collaboration.

34. The finding that intra-day adjustments have major potential benefits should have led the SEM Committee to examine in detail how best to achieve an efficient cross-border despatch (starting from any portfolio of day-ahead trades). Instead, the SEM Committee has mainly considered each Option from the point of view of its contribution to day-ahead trading. This misplaced focus on day-ahead trading has distorted the SEM Committee's review of each Option and biased its draft decision.

### 3.3.2. Example (B): despatch outcomes

35. The DAM, ID and Balancing markets are described as "exclusive" methods of arranging for a generator to run. However, there is no analysis in the IIA to show whether these methods are sufficient to achieve an efficient outcome under Option 3. Specifically, paragraphs 5.4.54-57 of the IIA focus only on the *liquidity* of day-ahead and intra-day trading under each Option. This section omits any consideration of *despatch processes* (including balancing), and does not consider the efficiency of *actual outcomes*. The discussion of the effect on liquidity is highly subjective and partial.

36. Respondents to the consultation have expressed reservations about the ability of individual generators to use Euphemia for scheduling their plant. When appraising Option 3, the SEM Committee *assumes* that the DAM will produce a reasonably efficient pattern of output,

[10] Table 14 on page 43 of the IIA gives a NPV of cost savings due to efficient intra-day trading of €537 million for "base case A" and €190 million for "base case B".

interconnector flows and demand,[11] whilst recognising that some balancing interventions will still be needed.[12] However, the SEM Committee does not accord the other Options the same benefit of the doubt. Instead, it assumes that the other Options will produce less efficient day-ahead schedules, *without consideration of the later effect of intra-day markets or balancing*. This appraisal of Options is therefore selective and biased.

### 3.3.3. Effect on wider evaluation of Options

37. The focus on day-ahead cross-border trading and liquidity sets up an intrinsic bias in favour of any model with organised day-ahead and intra-day trading (i.e. Option 3), and against models with more emphasis on self-scheduling, centralised despatch or *ex post* pooling (i.e. Options 1, 2 and 4). The SEM Committee has not fully considered measures that would promote liquidity in any Option. However, even if the day-ahead and intra-day markets within Options 1, 2 and 4 are less liquid than in Option 3 (which the DDP rates as important), they may produce more efficient outcomes in terms of actual despatch and interconnector flows (which is more important for consumers in the long run). The SEM Committee overlooks this possibility.

### 3.3.4. Summary

38. We discuss examples here that show how an undue emphasis on trading (combined with a lack of clarity over real time and ex post institutions) led to the SEM Committee's appraisal in the DDP and IIA being unduly subjective and biased in favour of Option 3. The lack of detail about real-time and ex post institutions affects the SEM Committee's appraisal of all the so-called "high level designs".

39. We consider the question of efficient despatch and its link to the DAM in more detail in sections 5.3 and 5.4. We return to the SEM Committee's discussion of interconnectors further in section 5.5. We consider liquidity and efficiency further in section 5.6.

## 3.4. Conclusion

40. The SEM Committee has justified a reform of the SEM by accepting the immediate requirements of the EU Target Model. Specifically, the description of each Option focuses on the requirements for market-coupling, which the RAs have defined as more or less synonymous with day-ahead trading. However, day-ahead trading concerns a *derivative* product. The SEM Committee has neglected the intra-day and real-time institutions that determine actual output, demand and prices for the *underlying commodity*. The "High Level

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[11] The assumption of an efficient outcome is intrinsic to the treatment of cross-border flows over interconnectors, as discussed above. Unless the DAM produces an efficient outcome for the I-SEM, there is no basis for claiming that it will also decide the direction of cross-border flows efficiently.

[12] "As discussed previously, the SEM Committee considers that EUPHEMIA will be a robust and reliable means of developing an unconstrained day ahead schedule in I-SEM. The contracted volumes from EUPHEMIA are notified to market participants and the TSO with hourly granularity. A process will be required by which all hourly products from EUPHEMIA are converted into a more granular nomination profile, which the TSO can utilise for system dispatch, based on generator physical constraints, such as ramp rates. Further work is required to establish the respective roles of market participants and the TSO in this process." (DDP, paragraph 6.4.56)

Designs" being appraised in the DDP and IIA are therefore incomplete. The missing details are required to support any robust, objective appraisal.

41. The incomplete description of the Options undermines the value of the SEM Committee's appraisal. We conclude that the decision to select Option 3 is not based on a full understanding of its implications and is biased by the focus on a limited set of each Option's features. As we discuss in the next chapter, the SEM Committee's appraisal criteria failed to restrain or correct this bias. The SEM Committee's draft decision is therefore unsound.

42. It will not be possible to construct a new electricity market without considering real-time institutions. Given the lack of attention these matters have received in the high level design phase, resolving the outstanding questions will require significant work during the detailed design phase.[13] Experience to date suggests that this task cannot be awarded to an individual advisor, but that the process must provide scope for technical advice and external scrutiny from all interested parties.

[13] The detailed design phase may well bring to light aspects of the chosen Option that overturn the assumptions underpinning its selection. To ensure that the final design meets all the necessary criteria in the detailed design phase, the designers will need sufficient flexibility to allow radical amendment of the chosen Option, or even the adoption of a different Option (amended as appropriate). Similar findings apply to the SEM Committee's specification and evaluation of CRMs, which indicates a corresponding need to retain flexibility over their design in the next phase of the decision process, as we discuss in chapter 6.

# 4. Adopting Practical Appraisal Criteria

43. The DDP and the IIA (in particular) reach conclusions based on arguments that are not robust, correct or logical. Parts of the appraisals set out in these documents contain statements that simply cannot be assessed or even understood by third parties, because they are ambiguous, vague or subjective. Some of these problems derive from the lack of a detailed description for each Option (see chapter 3), but many of the weaknesses in the arguments derive from the use of vague or undefined appraisal criteria, as we illustrate below.

44. For instance, paragraph 5.6.9 of the Initial Impact Assessment says that "Option 2 does not fit naturally into existing types of balancing arrangements". This statement is meant to indicate a disadvantage of Option 2, but it is so vague as to be meaningless. EirGrid has said that it can operate securely with any of the Options,[14] so a supposed inability to "fit naturally" into balancing does not put security of supply at risk. There is no way to know what this statement means or how this statement affected the SEM Committee's choice, so it is impossible to check its validity.

45. Such vagueness arises partly from the unclear definitions (and/or variable definitions) of the assessment criteria set out by the SEM Committee. Those criteria seem to be intended to reflect the requirements of the EU Target Model, which we discuss in section 3.1 above and explain further in Appendix A. The SEM Committee has chosen to define appraisal criteria in very broad terms, which makes them open to many different interpretations, as discussed in section 4.1 below. The resulting flexibility allows the SEM Committee to interpret its criteria differently when appraising different Options and CRMs.

46. To eliminate this problem, it will be necessary to define appraisal criteria less ambiguously. In section 4.2, and in more detail in Appendix B, we show how such criteria can be defined.

## 4.1. The SEM Committee's Assessment Criteria

47. The IIA lists the criteria used to assess the various electricity market designs (i.e. the energy trading Options and Capacity Remuneration Mechanisms), dividing them into primary criteria (driven by legal requirements) and secondary criteria (standard principles of regulation),[15] although the distinction does not appear to affect their use in the IIA and DDP. The SEM Committee sets out its appraisal criteria as follows:

- Primary
  - Internal Energy Market
  - Security of Supply
  - Competition
  - Environmental; and
  - Equity

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14 IIA, paragraph 5.6.24.

15 IIA, paragraphs 1.2.5-1.2.6.

- Secondary
  - Adaptive
  - Stability
  - Efficiency
  - Practicality

48. There appears to be a problem with the application of these appraisal criteria. As discussed above, the current reforms are driven largely by the requirements of the Internal Energy Market, and the desire to implement the EU Target Model. (See section 3.1.) The SEM Committee has therefore focused on the requirement in that model for day-ahead cross-border trading. That focus appears to have led the SEM Committee to apply some of the criteria (especially efficiency and security of supply) predominantly to the operations of the day-ahead market. A full appraisal would instead have considered the implications for these criteria of outcomes of the whole system, i.e. both trading by market participants and real-time despatch by TSOs.

49. Indeed, the SEM Committee's appraisal seems to be unduly weighted towards the creation of a "liquid" day-ahead market, even though the DDP and IIA do not list "liquidity" as an explicit appraisal criterion. This *ad hoc* focus on liquidity substitutes on occasion for proper consideration of the impact of different Options on electricity sector operations overall. For instance, as we show in section 3.3.1, the analysis of flows over the interconnector considers the efficiency of day-ahead *arbitrage* between neighbouring markets, but not the efficiency of real-time *generation and consumption*. This tendency has biased the appraisal of the different Options.

50. Without conducting a full appraisal, it is difficult to say whether addressing the bias in the SEM Committee's initial appraisal would change its decision. However, the SEM Committee is recommending a new system to market participants and RAs based on an appraisal that does not take into account all the implications for generators, consumers and the RAs themselves. The SEM Committee's application of its assessment criteria does not therefore provide a sound basis for reaching a decision based on all the relevant evidence.

## 4.2. Practical Design Criteria

51. In Appendix B, we list an alternative set of design criteria for electricity markets (i.e.energy trading and capacity remuneration), drawing on the economic principles of efficient market operation in a sector characterised by long-lived investment. These criteria capture objectives listed in documents supporting the EU Target Model – specifically the CACM Guidelines and the Balancing Guidelines. They also correspond to the primary and secondary assessment criteria of the SEM Committee. However, they provide a more precise, objective and practical basis for assessing different electricity market designs than the SEM Committee's own appraisal criteria.

52. Some of the correspondences between our criteria and the SEM Committee's criteria require explanation.

- First, the need to meet the requirements of the EU Target Model within the Internal Energy Market lies outside economic criteria. We have therefore omitted it from our list, but we take it as the basic motivation for the current reforms.
- Second, economic efficiency is a broad term which encompasses many other criteria, not least environmental concerns (known to economists as "internalising an externality"). We therefore only refer to environmental aims separately from efficiency, where renewable energy policy raises specific concerns.
- Third, we have not included any criterion corresponding to the SEM Committee's desire for "practicality", as we intend this whole list to provide a more practical guide to electricity market design.

53. Our design criteria are divided into three sub-sets: (1) those that apply to the overall architecture of the market infrastructure, i.e. to the whole set of markets in which electricity is bought and sold; (2) those that apply to the design of individual markets; and (3) those that apply to measures for mitigating market power. A well-designed electricity market will meet all the criteria in all three sub-sets. In some cases, failing to meet one criterion might be justified by better performance on another criterion. However, only meeting all the design criteria will ensure that electricity markets produce efficient outcomes that benefit consumers. We derive and explain our criteria in Appendix B, below.

### 4.2.1. Market Infrastructure

54. We begin by setting out practical design criteria reflecting the economic principles that apply to the design of the overall system (with the corresponding "primary and secondary principles" of the SEM Committee shown in square brackets):

(1) Market design must permit secure operation of the system by the TSO, so that generation always matches demand. [**security of supply**]

(2) Market pricing rules (in conjunction with any capacity remuneration mechanism) must allow total generation capacity that is efficiently selected (investment) and operated (despatch) to recover its costs. [**efficiency/environmental**]

(3) "Gate closure", i.e. the time when central despatch and administrative pricing take over from decentralised contracts and trading, should occur at the latest possible stage before delivery. [**security of supply, competition, efficiency/environmental**]

55. Two further principles arise as corollaries to the desire to attract efficient investment:

(4) The market design should allow traders at all times (1) to maintain a contract portfolio that hedges the price of their expected output, and (2) to change their contract position if their expected output changes. [**efficiency/environmental**]

(5) The electricity market infrastructure, the format of offer/bid prices and market pricing rules should allow non-discriminatory access by all generation and DSR technologies. [c**ompetition, equity, efficiency/environmental**]

### 4.2.2. Market Organisation

56. Any individual electricity market must also meet the following criteria:

(6) The market or despatch algorithm should select offers (and bids) in an efficient least-cost "merit order". [**efficiency/environmental**]

(7) Prices should reflect marginal costs in the geographic market concerned, i.e.: (1) the "system marginal cost" for markets covering the whole system; (2) the "local marginal cost" of individual generators operating within a local market (e.g. for generators that are "constrained on" or "constrained off" and running out of merit). [**efficiency**]

(8) Prices should reflect marginal costs over the timescale of decisions associated with trading in the market concerned. [**efficiency**]

(9) Pricing rules should offer market participants the assurance that:

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- generators will generate whenever the price is above their marginal costs;
- generators will not generate if the price is below their marginal costs;
- generators will receive a price above their marginal costs when they generate; and
- equivalent rules apply to the acceptance of offers submitted to markets;

(10) equivalent (but obverse) rules apply to the supply of, and bids from, despatchable DSR. [**efficiency**]

(11) Price-setting rules should be transparent (i.e. they should use objective data in pre-defined formulae). [**efficiency, stability, adaptive**]

### 4.2.3. Market Power

57. The DDP and IIA recognise the need for measures to mitigate market power in markets for energy and capacity. Competition policy is a complex matter, but any measures adopted to mitigate market power should meet the following criteria to avoid undermining the performance of electricity markets by other criteria, particularly the efficiency of investment and operations.

(12) Measures to mitigate market power should be transparent (i.e. use objective data in pre-defined procedures). [**competition, efficiency, stability, adaptive**]

(13) The existence of market power in one market should not preclude competitive entry or supply of services in a related market. [**competition, efficiency**]

## 4.3. Conclusion

58. Much of the argumentation in the DDP and IIA is weak, vague, selective or subjective. Some of the appraisals appear to be incomplete and hence prejudicial. We attribute this problem to the lack of clarity in the definition of the SEM Committee's appraisal criteria.

59. We also note that a focus on the EU Target Model has given the appraisal an undue emphasis on efficient arbitrage in individual markets, and on trading in contract derivatives, instead of focusing on the efficiency of generation and consumption of electricity, the underlying commodity. See chapter 3.

60. Electricity markets serve a role in helping market participants to make decisions about production and consumption, and so contribute to achieving the high level aims of efficiency

and security of supply. However, it would be wrong to focus on the performance of any individual market or markets as a final objective of electricity market design. Above, therefore, we have set out practical design criteria that focus attention on the ultimate outcomes, i.e. the actual outcomes for the generation and consumption of electricity that determine costs and prices, security of supply and economic efficiency.

61. Markets and trading provide a form of social organisation which is useful when it achieves certain objectives. However, the creation of a liquid market is not an objective in itself. It is therefore a mistake to abandon other objectives in the cause of promoting “liquidity”. Unfortunately, the SEM Committee appears to have done just that. Our restatement of the appraisal criteria provides a better basis for assessing the Options and the role of individual markets.

62. With regard to the various CRMs, the SEM Committee placed great emphasis on the desirability of “market based” institutions, favouring Reliability Options for that reason. However, the SEM Committee does not define “market based” or explain how this term relates to the appraisal criteria set out in the IIA. Moreover, Reliability Options only appear to be “market based” becasuse they are incompletely specified in the IIA and DDP, certain regulatory requirements having been overlooked.

63. In summary, the SEM Committee has listed appraisal criteria that are vague and open to a wide range of interpretations. The DDP and the IIA apply other, unstated criteria such as “liquidity”. Overall, we conclude:

- that the SEM Committee’s appraisal of the Options and Capacity Remuneration Mechanisms is not based on equal application of objectively defined criteria, but on the selective use of subjectively defined criteria and *ad hoc* considerations; and
- that the SEM Committee’s decision is therefore unsound.

# 5. Energy Market Arrangements

64. As discussed above, the descriptions of the Options for energy trading are incomplete, whilst the appraisal criteria used by the SEM Committee are defined vaguely and applied in a selective manner. These conditions are not conducive to a thorough and objective appraisal of the Options. Indeed, as might be expected, we found several problems with the appraisal set out in the DDP and the IIA. Below, we set out some of the most important problems with the SEM Committee's appraisal of energy market Options.

## 5.1. The "Qualitative Appraisal"

65. Chapter 5 of the IIA includes a "qualitative appraisal" of the Options, which discusses the Options by reference to each of the SEM Committee's appraisal criteria in turn. Unfortunately, this appraisal is selective and biased, as in practice it applies different criteria to different Options. The definition of the criteria is not rigorous and seems to differ according to circumstances. The appraisal does not treat all four Options equally, but often discusses only the advantages of Option 3, as if it had already been selected, instead of using the discussion to drive the selection. Appendix D provides a more detailed review of this part of the IIA.

66. Overall, the "Qualitative Appraisal" set out in the IIA provides no objective or balanced support for the SEM Committee's draft decision.

## 5.2. Errors Caused by Poor Definition of the Options

67. Some of the most important aspects of the High Level Design are mentioned in only vague terms. However, they have the potential to affect outcomes significantly, and cannot therefore be ignored in any overall evaluation of different Options.

### 5.2.1. Unspecified design details

68. Under Option 3, the SEM Committee has decided to adopt a "single imbalance pricing regime".[16] All imbalances within the same imbalance settlement period will be settled at the same price, whether the "Balance Responsible Party" is long (net contract position greater than net physical generation) or short (net contract position less than net physical generation). The DDP does not say how this price will be set, although it mentions that it will reflect "the costs of actions taken by the TSOs", implying that the imbalance price will be taken from the offers and bids accepted in the balancing market. (Criteria (6)-(11) would apply to this aspect of the design.)

69. Within the balancing market, the SEM has decided to employ a "marginal pricing mechanism", under which the price for all "activated balancing energy" will be taken from the offer or bid price of the "last" unit that the TSO uses to provide balancing energy.[17] That corresponds to a decision to apply our criteria (7) and (8). In Options 2 and 4, which contain

[16] DDP, paragraph 6.4.49.

[17] DDP, paragraph 6.4.45.

an ex post pool, the "last" unit is the most expensive one required to meet demand, which can be identified within the pooling algorithm (as under the current regime). In Options 1 and 3, however, the TSO may intervene at any time, so the definition of the "last" unit is unclear or ambiguous. This term may mean the last unit *chronologically*, i.e. the price of the offer or bid accepted by the TSO at the time closest to delivery. On the other hand, it may mean the most highly priced offer (or the lowly priced bid) accepted during the lead up to delivery.

70. Whatever it means, price-setting will exclude TSO balancing actions that are driven, not by overall market conditions or surplus or deficit, but by potential gains from trade (i.e. matching low-priced offers with high-priced bids), or by some local constraint. The list of offers and bids eligible to set the imbalance price (which then determines the value of all other electricity contracts) will be adjusted by a "tagging and flagging" system, applied at the discretion of the TSO.[18] Such processes may not be consistent with the need for transparency in price setting. (Criterion (11))

71. Within Options 2 and 4, the price of imbalances would be derived from the ex post pool, leaving no doubt about which outputs can be included in, and which can be omitted from, the calculation of imbalance prices. Within Options 1 and 3, however, price setting will have a subjective element. Within BETTA (which is similar to Option 1), this subjectivity has limited impact, because imbalance prices are in any case intended to be unpredictable, different for surpluses and deficits, and punitive, in order to discourage imbalances. However, the Balancing Guidelines specify the use of a single balancing price. That approach is now being applied in both BETTA and the I-SEM (Option 3).[19] However, as yet, it is unclear how a single electricity market price can be centrally defined in a transparent manner, without relying on an automated schedule of generation (which is only found in Options 2 and 4).

72. Thus, by leaving the imbalance pricing rule undefined, the DDP and IIA overlook a potential problem with Options 1 and 3 and fail to identify a potential advantage for the other Options.

### 5.2.2. Appraisal errors due to mis-specification of Options

73. Failure to be specific about real-time arrangements has caused analytical errors in the SEM Committee's appraisal, as illustrated by paragraphs 6.4.23 and 6.4.24 of the DDP.

74. Here, the DDP considers an effect of making the DAM "non-mandatory" and describes a situation where wind (or renewable energy) does not participate in the DAM. It claims that the result will be (a) higher prices and (b) a higher cost initial schedule comprising only thermal generation. Those outcomes rest on the assumption that the restricted supply of generation is set against the same level of demand as before – possibly even a forecast of total demand. However, it is hard to envisage market rules that exclude some generators from the DAM without also adjusting the demand by an equivalent amount, so the outcomes (a) and (b) are unlikely to arise in practice.

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[18] DDP, paragraph 6.4.45.

[19] The decision to move to a single imbalance price was announced in mid-May 2014, by the British electricity and gas regulator, Ofgem. See Ofgem (2014), *Electricity Balancing Significant Code Review - Final Policy Decision*, 15 May 2014.

75. The proposed model – with the DAM being "exclusive" but not "mandatory" – implies that demand enters only through voluntary bids from suppliers, not as a centralised forecast of total demand. Suppliers would not bid for electricity in the DAM, if they expected to pay a higher price than in intra-day markets. Due to the potential for arbitrage between day-ahead and intra-day markets, the reduction in day-ahead offers to sell would be matched by a reduction in day-ahead bids to buy. Prices in the DAM would remain comparable with expected prices in the intra-day market – and with the expected price of imbalances, which ultimately determines the value of all contracts signed in advance of delivery.

76. One effect of this arbitrage would be to split trading volumes between the DAM and other markets, thereby reducing liquidity in all of them. Neither the DDP nor the IIA note the likelihood of this outcome. Instead, they take for granted the liquidity of the DAM under Option 3, an assumption based apparently on an earlier design, in which participation in the DAM was mandatory. The SEM Committee is therefore basing its appraisal of Option 3 on an out-dated specification.

77. The fears expressed in the DDP about the effect of making the DAM non-mandatory and excluding wind farms from the DAM therefore indicate either a misunderstanding of electricity markets, or some hidden assumptions about electricity market design that would not withstand scrutiny. The SEM Committee appears to have overlooked the implications of this analysis for market liquidity. Its appraisal of Option 3 appears to be based on an out-dated version, which would perform differently from the latest version in terms of promoting liquidity. Since promoting liquidity is one of the supposed advantages of Option 3, the SEM Committee's decision, which relies on this feature of Option 3, must be regarded as unsound.

### 5.2.3. Summary

78. These observations indicate gaps in the definition of the chosen Option and its potential effects that might have altered the SEM Committee's appraisal of the Options, judging by our practical design criteria (Criteria (1), (2), (6) and (11), at least). The SEM Committee would need to carry out more analysis to ensure that the chosen Option meets the criteria of efficient market design (particularly by Criteria (6)-(9)). Lacking that analysis, the SEM Committee conducted a selective and prejudiced appraisal of the Options and has reached a decision that is unreliable.

## 5.3. Inefficiency and Scheduling Risk Due to Euphemia

79. The SEM Committee assumes that market participants will find a way to achieve the desired – i.e. efficient – pattern of output from their generators, even though the primary route to despatch will be a trading algorithm (Euphemia) rather than a despatch programme. This assumption lies behind the SEM Committee's positive appraisal of Option 3 and its focus on the DAM. However, it is not a foregone conclusion that market participants will achieve an efficient pattern of output and demand through their use of Euphemia in the DAM or other markets. Assuming an efficient outcome is not a sound basis for the SEM Committee's decision, as we explain below.

### 5.3.1. Trading algorithms versus despatch programmes

80. Unlike a despatch programme, Euphemia does not accept offers and bids in a structure that accurately reflects the costs and technical characteristics of individual generators. Instead, Euphemia offers market participants several ways to submit data that are intended to reflect generator characteristics in simplified offer formats. Generators have to choose which of these simplified offer formats best reflects their actual characteristics and how to adjust input data for differences between the simplified offer formats and the complex reality. This discretion over the choice of offer format creates a degree of unpredictability for each user of the system. Different market participants may choose to reflect the complex characteristics of their generators in different ways in response to changing assumptions regarding key attributes of the DAM such as the level of wind generation or demand. The actual outcome achieved by each market participant will then depend not only on how they adapt their own offers for any given day, but also on their ability to predict how other market participants will adapt their offers.

81. No final assessment of the Options will be possible if the SEM Committee cannot be sure that generators have the means to achieve predictable levels of output, consistent with economic merit-order despatch. (Criterion (9)) Euphemia has been developed as a means of trading energy in other countries. Testing of Euphemia is required, to confirm the assumption that it provides a suitable basis for despatching generators in Irish conditions.

### 5.3.2. Alternative means of achieving efficient production

82. Each Option includes some kind of intra-day market and a balancing mechanism, but the high level descriptions do not say how the TSO will interact with market participants.[20] Market participants wish to operate their generators at least cost, but their plans may conflict with the TSO's need for a feasible and secure pattern of flows over the transmission system. The TSO needs to know when to make balancing trades to rectify problems. To intervene efficiently, the TSO needs to possess a definitive plan for each market participant's generation and consumption.

- If the TSO intervenes too early, before market participants have finalised their plans, they may simply re-create a problem by engaging in another intra-day trade, which will require another round of intervention by the TSO.
- If the TSO intervenes too late, it may only be able to select from a restricted set of expensive, flexible sources of upwards or downwards ramping.

83. These aspects of the market design have the potential to cause inefficient outcomes. This potential differs between the Options, but the DDP and IIA do not take it into account.

[20] In the DDP, paragraph 6.4.57 notes that it will be necessary to decide how day-ahead nominations should be linked to contractual positions, if at all, but it provides no answer to this question.

### 5.3.3. Summary

84. The use of Euphemia in the day-ahead market is not guaranteed to produce an efficient pattern of output. Intra-day and real-time institutions may correct any forecasting or trading errors, but only if well designed. Unless these institutions are well defined and understood, the market has the potential to produce inefficient outcomes.

85. Including a proper assessment of this potential inefficiency might overturn the SEM Committee's appraisal of the Options and change its decision about the High Level Design. In the absence of any such assessment, the SEM Committee's conclusions are not soundly based.

## 5.4. Confusion Over Contract Types and Despatch Rules

86. Paragraphs 6.4.3-6.4.5 of the DDP discuss the choice between "physical" and "financial" contracts, with the SEM Committee ultimately proposing "that all forward contracts will be financial in nature, i.e. Contracts for Differences (CfDs)." The reasoning behind this proposal has two parts:

- "Financial contracts can achieve everything that can be achieved by physical forward contracts in terms of hedging short term spot prices…" (para 6.4.3); and
- "…physical forward contracting could aggravate rather than mitigate liquidity concerns by reducing the volumes of trades in the short term markets that are used to reference financial contracts" (para 6.4.4).

87. These reasons only refer to limited aspects of contracting, namely the hedging of "short term spot prices". Respondents may in fact be using the difference between physical and financial contracts to highlight other aspects of risk management, which the SEM Committee has ignored, and which we explore below.

### 5.4.1. Real time price risk

88. The DDP envisages the day-ahead market as the source of the reference price for a variety of financial contracts ("Contracts for Differences" or CfDs). However, generators also need some way to hedge price risk for variations in output arising after the day-ahead stage, in the intra-day markets, balancing mechanism and settlement of imbalances.

89. The multiplicity of prices after the day-ahead stage will present a challenge for contract designers trying to develop CfDs for hedging these risks. Leaving aside special operations required by the system, Nord Pool settles all real-time volume adjustments in the same hour and zone at the same market price, whether they derive from a balancing instruction issued by the TSO, or from an imbalance attributable to a market participant. Under that approach, a large number of market participants face similar price risks, so those with surpluses can offer CfDs at a predetermined strike price to those with deficits. That solution will not be feasible in the SEM Committee's chosen option, where intra-day markets, balancing trades and imbalances all attract different prices.

90. To offer all market participants a common basis for hedging short term prices would require a unified real-time or *ex post* market operating after the day-ahead market (as in Nord Pool).

The DDP does not consider any such model, or attribute any benefit to models that might be able to operate this way.

### 5.4.2. Real time volume and scheduling risk

91. If contracts refer to the price in the DAM, generators who cannot predict their actual output at the day-ahead stage will be exposed to variation in the value of the difference between day-ahead sales and actual output ("volume risk"). Generators using renewable energy sources are particularly exposed to this risk but it will affect others who find it difficult to achieve a particular level of sales in Euphemia ("scheduling risk").

92. Euphemia will be used in the DAM to determine each generator's sales and the reference price that determines payments under CfDs. If a generator cannot match its sales in the DAM to the volume of its CfDs settled by reference to the DAM price, it will be exposed to price risk on the difference. Generators will not be able to reduce this exposure by trading in intra-day markets, as shown in Box 1 on page 22**Box 1**. The resulting increase in financial risk may raise the costs of generation borne by consumers through the wholesale electricity market.

### 5.4.3. Implications for market design

93. Some market participants expressed a desire for physical contracts, which are not permitted in Option 3. The SEM Committee has stated a clear preference for financial contracts over physical contracts. However, it is not clear that the SEM Committee has understood or addressed the concerns of market participants. It appears that market participants may have recommended physical contracts, not as a contract form per se, but as a means of managing scheduling risk within the general process of scheduling and despatch.

94. In wholesale electricity markets, so-called "physical" contracts do not in fact dictate how much the seller must generate or how much the buyer must consume. A physical contract merely requires the parties to notify the contract volume to market, which offsets it against their obligations within that market. For example, under BETTA in Great Britain, contracts are offset against the obligation to pay for *ex post* imbalances. The incentive to generate then comes from the desire to avoid being charged for an imbalance at a price above the cost of one's own generation.

95. In these markets, the process of notifying contract volumes is associated with a right to schedule the output of one's own generators ("self-scheduling").[21] This right avoids exposing market participants to the "scheduling risk" inherent in unpredictable despatch programmes. The need to manage this scheduling risk seems to lie behind the desire of market participants to use physical contracts, not the form of the contract per se.

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[21] Under BETTA, market participants notify their contract volumes separately from their expected generation ("physical notification"). If there is any difference between the two at the final stage, the latter provides a pre-notification of the intention to run an imbalance, for the benefit of the TSO and its operations. In general, market participants try to match their final contract notifications against their expected generation and consumption.

**Box 1: Effect of Day-Ahead Imbalances Against CfDs**

1. Suppose a generator sells 100 MWh of financial CfDs with a strike price of €50/MWh (equal to its SRMC) and with the DAM price as a reference price. The table below shows the cash flows for a fully hedged generator in a particular half-hour J, when the DAM price is €75/MWh, the CfD is called, the generator produces 100 MWh and it sells 100 MWh in the DAM. The generator's cost of generation is €5,000, its revenue from the DAM is €7,500 and its net rebate to the buyer is €2,500. The generator's net cash flows are €0, meaning *it is perfectly hedged*.

| Source of | Prices | | Volumes | | Cash Flows | | |
|---|---|---|---|---|---|---|---|
| Cash Flow | Cost | Revenue | Cost | Revenue | Cost | Revenue | Net |
| Units: | €/MWh | €/MWh | MWh | MWh | € | € | € |
| Generation | 50.00 | | 100 | | 5,000 | | -5,000 |
| DAM | | 75.00 | | 100 | 0 | 7,500 | 7,500 |
| CFD | 75.00 | 50.00 | 100 | 100 | 7,500 | 5,000 | -2,500 |
| Total | | | | | 12,500 | 12,500 | 0 |

2. Suppose however that the scheduling risk in Euphemia causes the generator to sell only 60 MWh in the DAM for half-hour J. The generator has shortfall against its CfD volume of 100 MWh, leaving it exposed to the difference between the strike price and the DAM price for 40 MWh. To close this gap, the generator might try to sell another 40 MWh in the intra-day market, *but that will not provide a perfect hedge.*
3. The table below shows the result if the intra-day price falls back to €55/MWh, giving a revenue on sales of 40 MWh (€2,200) that is insufficient to cover the cost of fulfilling the exposed part of the CfD (€3,000=€7,500×40/100). The generator ends up €800 short.

| Source of | Prices | | Volumes | | Cash Flows | | |
|---|---|---|---|---|---|---|---|
| Cash Flow | Cost | Revenue | Cost | Revenue | Cost | Revenue | Net |
| Units: | €/MWh | €/MWh | MWh | MWh | € | € | € |
| Generation | 50.00 | | 100 | | 5,000 | | -5,000 |
| DAM | | 75.00 | | 60 | 0 | 4,500 | 4,500 |
| Intra-Day | | 55.00 | | 40 | 0 | 2,200 | 2,200 |
| CFD | 75.00 | 50.00 | 100 | 100 | 7,500 | 5,000 | -2,500 |
| Total | | | | | 12,500 | 11,700 | -800 |

4. For a generator, therefore, the scheduling risk in Euphemia translates into *either* a volume risk (if day-ahead sales differ from CfD volumes and the generator takes no further action) *or* a price risk (if day-ahead sales differ from CfD volumes and the generator tries to bridge the cap with trades in intra-day markets).

96. The SEM Committee's consideration of different contract types only looks at price risk and says that financial contracts (CfDs) can hedge short term spot prices just as well as physical contracts. However, market participants gain no benefit from hedging short term spot prices, if they cannot be sure that the volume they generate or consume matches the volume in their hedging contracts ("scheduling risk").

97. The DDP and IIA suggest at various points that allowing self-scheduling and physical contracts, or allowing Physical Transmission Rights on interconnectors, would reduce liquidity in the DAM. That seems to be based on a hidden assumption (and possibly a misunderstanding) about the way in which such arrangements would be reconciled with the DAM. The DDP states that the DAM will offer an "exclusive" method of establishing contract or physical nominations day-ahead (although that is not quite clear yet – see DDP, paragraph 6.4.57). If so, holders of physical contracts or transmission rights would probably offer their contracted capacity into the DAM. They would have the same incentives as the owners of generation capacity to enter them into the DAM as capacity for sale and the incentive might be reinforced by obligations. Indeed, the DDP notes in paragraph 6.4.5 that "the Iberian and Italian markets currently require all forward contracts to be nominated into the DA power exchange". If the RAs imposed similar obligations on the I-SEM, PTRs on interconnectors would appear in the DAM. Having physical contracts would then contribute towards liquidity (i.e. volumes) on the DAM, rather than diminishing it.

### 5.4.4. Summary

98. In the DDP, the SEM Committee does not address the problem of volume/scheduling risk, except by expressing a hope that generators will learn how to achieve their aims through Euphemia (DDP, paragraphs 6.4.30-6.4.36). The existence of such risks would raise the costs of generation and increase prices to consumers. A full assessment of the options would therefore have considered this problem in detail, taking into account a detailed description of the arrangements for scheduling and despatch. This detailed description is missing from both the DDP and the IIA.

99. Exposure to volume and scheduling risks will affect investment incentives. Generators may be able to develop CfDs that provide an *ex post* hedge against imbalance prices, but doing so would split liquidity between the day-ahead and other markets, which would undermine many of the claims in the DDP about the benefits of Option 3. In contrast, any market model with a single real-time or *ex post* market (as well as a day-ahead market) might offer market participants the opportunity to manage such risks, but the DDP does not recognise this possibility. Discussion of the day-ahead market, reference prices and contracting should therefore consider explicitly all the real-time risks facing generators and how they might manage them. (Criteria (2), (3) and especially (4), but also (9)). Currently, the DDP and IIA lack any discussion of these risks.

100. The DDP and IIA are missing any description of important parts of the alternative trading and despatch arrangements, and fail to consider the associated risks to market participants. The appraisal of the proposed Options is therefore incomplete and necessarily subjective.

## 5.5. Mis-Specification of Interconnector Impacts

101. The treatment of interconnectors forms a major part of the evaluation of Options for the I-SEM. That is understandable, given that the current reform proposals are intended to promote more efficient cross-border flows within the EU's internal electricity market. However, the SEM Committee has not properly specified the output variables that are relevant for its appraisal, leading to a decision that is based on an incorrect definition of efficiency and an incomplete specification of the market model itself, as explained below.

### 5.5.1. Incorrect definition of efficiency

102. The DDP discusses the treatment of interconnectors in paragraphs 6.4.7-6.4.20. Section 5.4 of the IIA contains detailed modelling of the Irish and British markets and the effect of using interconnectors inefficiently. This modelling shows that inefficient arbitrage between markets leaves potential gains from trade unused, but this finding is a foregone conclusion. The modelling itself does not provide any basis on which to distinguish between the Options.

103. Efficiency depends on the actual outcome of despatch and cross-border *flows*, not on the cross-border *trades* achieved in any particular market. The analysis set out in the IIA actually indicates the importance of achieving efficient cross-border flows in real time (given the day-ahead outcome). However, the DDP and IIA give little attention to real-time output and demand. Instead, the IIA distinguishes between Options by reference to their impact on the efficiency and liquidity of day-ahead trading.[22]

104. In practice, the efficiency of day-ahead trading may be unimportant for actual outcomes. Collaboration between TSOs could ensure efficient *use* of interconnectors in real time under any Option, by re-arranging cross-border flows in response to Balancing Market offers and bids. ACER's Balancing Guidelines oblige TSOs to collaborate to increase efficiency (see section 3.1), but the DDP and IIA never consider the nature of that collaboration or its effect on outcomes.

105. Indeed, the IIA never explains what the authors are assuming under each Option about UIOSI conditions on PTRs, on the potential for adjusting cross-border flows in the ID markets or on the role of the TSOs and the potential for optimisation of cross-border through inter-TSO balancing trades. Any of these mechanisms would affect the efficiency of actual outcome, regardless of the trading position achieved in advance in the DAM.

106. Having focused only on the efficiency of arbitrage, rather than efficiency of use, the IIA then assumes that cross-border linking of DAMs in Option 3 will achieve more efficient arbitrage than any other Options, or than "physical transmission rights" (PTRs).[23] However, these claims are mere assertions based on unstated assumptions about traders' behaviour under each Option. They are not backed up by analysis or evidence. Some of the claims seem to be based on contradictions or misconceptions.

107. For example, paragraph 5.4.39 of the IIA states that Option 2 faces a problem, because it will split liquidity between "the European DAM and the ex-post pool". However, a non-mandatory version of Option 3 offers a "European DAM" and a single price for *ex post* imbalances,[24] as well as intra-day markets, which offers the same potential for splitting liquidity. Yet the evaluation of Option 3 in paragraphs 5.4.40-41 makes no mention of this

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22 IIA, paragraphs 5.4.38-43.

23 IIA, paragraphs 5.4.40-41.

24 The SEM Committee proposes to use the balancing market to identify a single price for imbalances based on marginal cost, just as a gross pool would. "The SEM Committee proposed decision is that the balancing market will employ a marginal pricing mechanism. This means that the last unit used to provide balancing energy will set the price for all activated balancing energy. Marginal pricing is in line with the thrust of the EU target model for balancing." DDP, paragraph 6.4.44.

potential tendency to split liquidity, observing instead that “High levels of participation in the DAM and IDM by variable renewable generation will better deliver optimal use of the interconnectors”. We can see no reason for this favourable view of Option 3, given the problems that the SEM Committee has ascribed to Option 2.

108. Similar problems arise in the discussion of interconnectors. Appendix C sets out statements about FTRs and PTRs made in section 6.4 of the DDP and explains why they are incorrect or misleading.

### 5.5.2. Confusion over efficiency of different interconnector contracts

109. The DDP frequently states that offering physical transmission rights on the interconnectors will limit liquidity or efficiency.[25] However, it is not clear why this statement is necessarily true. The “exclusive” nature of the DAM process means that holders of physical interconnector capacity would have the same incentives to pass their sales through the DAM as the owners of any generator capacity. Interconnector capacity covered by PTRs would therefore offer as much liquidity to the DAM as generation capacity.

110. Moreover, normal despatch procedures – sometimes formalised as “use-it-or-sell-it” (UIOSI) or “use-it-or-lose-it” (UIOLI) rules – can make unused interconnector capacity available to other traders or to the TSOs on either side of the interconnector. As a result, traders with PTRs would not be able to withhold interconnector capacity,[26] and there is plenty of scope for intra-day adjustments to achieve efficient cross-border flows, no matter how efficiently or inefficiently arbitrage works at the day-ahead stage. If the UIOSI rule applied before the DAM closed, interconnector capacity would be available to the DAM on the same basis as under an implicit auction.

111. Indeed, many electricity markets have found it advisable to adopt PTRs, to make it possible for generators in neighbouring markets to offer reliable capacity. (See section C.3.3 in Appendix C.). The SEM Committee has not considered this possibility and so is forced to rule out cross-border trade in capacity (in favour of a compromise position on interconnector capacity). Allowing PTRs on interconnector capacity would therefore have a positive effect on security of supply, competition and liquidity (in energy and capacity markets), which the IIA does not take into account.

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[25] See DDP, paragraphs 6.3.14, 6.4.11-18. “One market participant believes that FTRs should result in the same practical outcome as PTRs with use it or sell it (UIOSI) requirements but that the benefit of FTRs is that physical capacity of the interconnector in the forward market is not used up, that that capacity is therefore available in the day ahead (DAM) and intraday markets and that this will assist liquidity in these timeframes. Concern is expressed that PTRs would mean taking interconnector capacity out of the market and reducing liquidity.” (DDP, para 6.3.14) “Furthermore, in order for the all island market to integrate further into the European Internal Market it is important that the existing interconnectors are used optimally. This will not only ensure that consumers in Ireland and Northern Ireland who have funded these assets receive adequate return on their investment but also that efficient signals are sent for future cross border investment, through competitive energy market prices on both ends of the interconnector. The SEM Committee believes that FTRs best achieve these objectives.” (DDP, para 6.4.17)

[26] At least, the incentive to withhold interconnector capacity will be no different from the incentive to withhold any other form of capacity. If such withholding is likely, the proposal faces a major problem not addressed in the DDP, which is not specific to interconnector capacity. In fact, withholding interconnector capacity is very difficult, if despatch procedures allow the TSO to make unused interconnector capacity available to others. However, the DDP has not set out detailed despatch procedures that would make this point clear.

112. It cannot therefore be argued that interconnector capacity covered by PTRs would somehow diminish liquidity. The statements about PTRs set out in the DDP are misinformed or misleading to readers.

### 5.5.3. Summary

113. Errors in the discussion of cross-border flows, and a failure to consider fully the alternative contract forms, effectively render invalid the conclusions reached in the DDP about the use of interconnectors.

## 5.6. Treatment of Liquidity, the DAM and Forward Markets

114. The DDP acknowledges on page 7 that measures will be needed to promote forward markets; this observation applies to all Options. However, the SEM Committee's appraisal of the Options is prejudiced by a biased treatment of this point, in favour of Option 3.

### 5.6.1. Selective use of the benefit of the doubt over liquidity

115. Paragraph 5.5.5 of the Impact Assessment accepts that Option 3 would need unspecified additional measures to promote liquidity in forward markets. Judging by experience in Britain, allowing for such additional measures would be particularly important for the appraisal of Option 1. However, the Impact Assessment does not consider whether additional measures would allow the other Options to perform as well as, or better than, Option 3 in this respect *or in any others* (e.g. in day-ahead liquidity, for example).

### 5.6.2. Failure to consider the proper role of forward markets

116. It is not the purpose of an electricity sector to create forward markets for their own sake. Forward markets have not proven necessary (in Britain, for example) to promote efficient investment in new generation capacity (which lasts much longer than any forward curve). However, forward contracts provide the basis for independent retail suppliers to set tariffs for the coming year or two. Without forward contracts extending at least one or two years into the future, independent retail suppliers would be unable to make such offers to customers and would lose out. In the context of the I-SEM, this situation would violate Criterion (13), since it would allow the dominant player in the generation market to extend its influence in the retail market, by withholding forward contracts and disadvantaging independent retail suppliers.

### 5.6.3. Summary

117. The robustness of the forward curve is a significant feature of any future electricity market intended to replace the SEM. However, in the appraisals set out in the DDP and IIA, the SEM Committee has allowed Option 3 to benefit from unspecified additional measures to promote forward markets, whilst not assessing whether these or other unspecified additional measures would be advantageous under Options 1, 2 and 4.

118. The assessment therefore fails to compare the Options on a level playing field. As a result, the conclusions reached in the DDP must be considered unsound.

## 5.7. Conclusion

119. The “Qualitative Appraisal” set out in the IIA provides no objective or balanced support for the SEM Committee’s draft decision.

120. There are gaps in the definition of the chosen Option and its potential effects that are significant enough to have affected the SEM Committee’s appraisals. More analysis would be required to ensure that the chosen Option meets practical and objective criteria of efficient market design. In the meantime, the SEM Committee’s appraisal is selective and prejudiced, rendering its decision unreliable.

121. Euphemia is not guaranteed to produce an efficient pattern of output in the day-ahead market, but the SEM Committee assumes that it will. In fact, given the lack of detail on intra-day and real-time institutions, any of the proposed High Level Designs has the potential to produce inefficient outcomes. Without a proper assessment of this potential inefficiency, the SEM Committee has no sound analytical or evidential basis for its decision.

122. The SEM Committee has not addressed the problem of volume/scheduling risk. A full assessment of the options would have considered this problem in detail, taking into account a detailed description of the arrangements for scheduling and despatch. The DDP and IIA are missing any description of these arrangements and fail to consider the associated risks to market participants. The appraisal of the proposed Options is therefore incomplete and necessarily subjective.

123. Errors in the discussion of cross-border flows, and a failure to consider fully the alternative contract forms, effectively render invalid the conclusions reached in the DDP about the use of interconnectors.

124. In relation to the liquidity of forward markets, the assessment fails to compare the Options on a level playing field. As a result, the conclusions reached in the DDP must be considered unsound.

125. We conclude:

- that the SEM Committee’s description of the Options is incomplete and in some cases erroneous;
- that SEM Committee’s appraisal of the Options is selective, subjective and prejudiced; and
- that the SEM Committee’s draft decision is not soundly based on evidence or analysis.

# 6. Capacity Remuneration Mechanism

126. In its Draft Decision Paper, the SEM Committee concludes that a "Reliability Option" (RO) is the Capacity Remuneration Mechanism (CRM) best suited to meeting the needs of the I-SEM. However, this conclusion is not soundly based because:

- the SEM Committee's description of ROs, and hence its evaluation of them, is *incomplete*;
- the SEM Committee's appraisal applies criteria in a *selective* manner; and
- the SEM Committee has evaluated CRMs against criteria that vary in scope and in definition, introducing a *bias* into the appraisal.

127. Because of these flaws in the appraisal of the various CRMs, the SEM Committee's choice is not soundly based.

128. In the following sections, we illustrate these points by reference to the arguments in the DDP and IIA. The comments below should be read alongside our two previous contributions on the topic: (1) a report on the choice of CRM,[27] submitted by Viridian in April 2014 in response to the RAs' Consultation Paper of 5 February 2014; and (2) a memo,[28] written at the request of the RAs, with more detail on Reliability Options and their role in solving the "missing money" problem.

## 6.1. Mis-Match Between Problems and Proposed Solutions

129. In chapter 7 of the DDP, the SEM Committee concludes that there is a need for a CRM in the I-SEM because:

- the risk of intervention to keep wholesale prices down deters efficient investment;
- reliability is a public good;
- there is inadequate DSR and insufficient long-term hedging, and
- large, indivisible investments may cause electricity prices in Ireland's relatively small market to follow a "sawtooth" pattern (which the SEM Committee views as a problem for plant that is exiting the market and for new entrants[29]).

130. In practice, a CRM will only address problem (1) if it removes the incentive for intervention, and will only address problems (2)-(4) if it changes incentives for investment in physical capacity. The SEM Committee appears to assume that Reliability Options (as specified in the DDP) will address these problems, but this assumption applies only in very specific

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[27] G. Shuttleworth, G. Anstey and M. Mair (2014), *The Capacity Remuneration Mechanism in the SEM*, Prepared for Viridian, 4 April 2014.

[28] G. Shuttleworth and G. Anstey (2014), *Reliability Options: Clarification Note*, 2 May 2014

[29] SEM Committee (2014), *Integrated Single Electricity Market (I-SEM) High Level Design for Ireland and Northern Ireland from 2016 - Draft Decision Paper*, SEM-14-045, 9 June 2014, Draft Decision page 58-59, para 7.2.5: "Notably, the indivisibility issue is an issue for exit as well as entry."

conditions that are not set out in the DDP or the IIA. The SEM Committee will compile a more detailed design in the next phase, but no proper evaluation of the various CRMs is possible at this stage without considering at least some of these detailed design features. If the SEM Committee had considered these detailed design features, it might have reached a different decision.

### 6.1.1. Removing incentives for intervention

131. First, the SEM Committee has not explained precisely how ROs will remove the incentive for political or regulatory intervention in electricity markets, and hence reduce the risk of such events occurring.

132. Adding ROs to the electricity market will only reduce or remove the risk of political or regulatory intervention in electricity markets in specific circumstances. For instance, ROs would reduce the political pressure on regulators to intervene in the following circumstances:

(1) Wholesale electricity prices feed directly through into the bills of retail customers;

(2) High wholesale electricity prices above a certain threshold (e.g. €1,000/MWh) raise the bills of retail customers above the level that is politically acceptable and provoke some kind of regulatory/political intervention to cap prices;

(3) Reliability Options (as specified in the DDP) offer a rebate to consumers when wholesale prices rise above the threshold;

(4) The rebate offsets the rise in consumer bills and prevents consumer bills from rising above the level that is politically acceptable;

(5) ROs therefore remove the incentive for regulatory/political intervention.

133. If this chain of argument lies behind the SEM Committee's conclusions, those conclusions are unsound, because several steps in this chain of argument may not be true in the I-SEM.

134. For instance, point (1) is most obviously true in a market where retail tariffs are regulated and are tied directly to wholesale electricity prices, but it may not apply in a market like the I-SEM, where retail tariffs are set competitively. In competitive conditions, unexpected rises in wholesale electricity prices, such as those that occur when capacity is short, do not feed through immediately into retail consumer bills.[30]

135. Furthermore, point (4) would only be true if there were a *direct* link between wholesale electricity prices and retail tariffs, *and* if the rebates paid under the ROs were passed on to retail consumers in direct proportion to their exposure to wholesale electricity prices. Under these conditions, high wholesale electricity prices lead to an increase in retail tariffs that is offset exactly by the rebate. Both these conditions might hold in a system of regulated retail

[30] We are assuming here that suppliers fix their tariffs for a certain period and can only adjust them prospectively. Unexpected price rises come and go before they can adjust tariffs. Expected price rises (due to an anticipated shortage of capacity) would be included in such tariffs, because they change suppliers' view of the likely future costs of supply. However, that effect would be muted and spread out over a long period, because it would reflect the probability of a shortage, rather then the full cost of an actual shortage. Such muted price increases are less likely to prompt political/regulatory interventions.

tariffs. However, these conditions may not hold in the I-SEM, at least not without a major overhaul of retail tariff regulation.

136. Without such detailed regulation of retail tariffs, rebates paid from generators to a central fund, and passed on to retail suppliers, may not benefit all consumers to the correct extent. In fact, they may not benefit consumers directly at all, as competing suppliers may have no incentive to pass on the actual rebates to their customers. Instead, they may include the anticipated level of rebates in a discounted price (just as they include the anticipated level of costs, rather than actual costs). Where suppliers offer their customers a fixed price, passing on any rebates they receive would harm their financial position (because they would be incurring higher costs to purchase energy, but receiving a fixed revenue from customers). Receipt of such rebates would have a perverse effect on their consumers (whose net cost of energy would fall at a time when electricity wholesale prices were rising).

137. The DDP and the IIA do not set out any explanation as to how ROs will reduce the risk of intervention. The analysis above suggests that ROs might not solve this problem, without a major overhaul of the regulation of retail suppliers. The SEM Committee's decision therefore fails to take account of potentially major effects and costs.

### 6.1.2. Replacing the missing money to encourage investment

138. In order to address the missing money problem, ROs would have to provide revenue in addition to that offered by the (imperfect) energy price. However, Reliability Options as specified in the DDP offer no particular advantage to investors and provide no additional incentive for investment over the wholesale market prices and contracts that would be available anyway.

139. We discussed this point in the memo dated 2 May 2014 and entitled "Reliability Options: Clarification Note", which Viridian duly forwarded to the RAs. In that memo, we explained that ROs would only offer additional revenue above the energy price if it was backed up by additional penalties for failing to provide capacity, as in the design currently being adopted in Great Britain (and in other countries' schemes as well).

140. In reply, to support its particular version of Reliability Options, the SEM Committee quoted two academic papers in the DDP, Vazquez et al (2003) and Cramton and Stoft (2008).[31] In practice, none of these authors support the position of the SEM Committee. On the contrary, these authors (and others) agree either explicitly or implicitly with the need for Reliability Options to be tied to physical capacity, as well as to the energy market, as shown below.

- **Vazquez et al (2003)**

141. Vazquez et al do not state explicitly that a Reliability Option settled by reference to the energy price is sufficient to solve the missing money problem. They note that Reliability Options solve a particular form of the missing money problem, i.e. the threat of regulatory intervention. We discuss above the conditions in which this statement is true and whether

[31] DDP, para 8.4.11, footnote 29.

this effect applies within the I-SEM. However, the description of their proposed design explicitly mentions the need for a physical link to the financial options bought in the auction. The relevant extract reads as follows:

> *"Additionally, a physical delivery obligation is tied to the option, in order to provide stronger incentives for the generators and to make sure that the more reliable production units will be in a better position at the reliability market. This means that an option-selling generator that, when the prices are high, fails to provide the power he committed to produce has to bear an extra penalty for each megawatt non-delivered."*[32]

142. Thus, although Vasquez et al acknowledge the potential benefit of ROs in reducing the temptation to intervene, they explicitly assume that ROs contain terms obliging generators to provide physical capacity, and to bear "an extra penalty" for not doing so, over and above the energy price.

- **Cramton and Stoft (2008), Cramton, Ockenfels, and Stoft (2013)**

143. In their 2008 paper,[33] Cramton and Stoft do not explicitly state that additional penalties are necessary, but they cite several systems where the TSO verifies that capacity is made available and they assume implicitly that generators must deliver capacity (which requires some kind of incentive and penalty system). The closest they come to stating this assumption is in relation to the variation of design required in a hydro-based electricity market:

> "If supply is mainly from hydro-electric generation, the limiting factor is not likely to be capacity (the ability to provide energy in peak hours) but rather, firm energy (the ability to provide energy in dry periods).[fn] As a consequence the TSO will need to purchase firm energy options. **Just as capacity is the physical basis for reliability options**, so firm energy options have a physical basis that involves a longer-term supply of energy."[34]

144. They made this assumption explicit in a more recent working paper, dated 2013.[35] That paper contains a discussion which is worth quoting at length. It explains the need to tie ROs to physical capacity, and the consequences of failing to define the amount of capacity ($C_{BID}$) that each generator may sell:

> **"d. Setting the capacity rating, CBID**
>
> So far, we have not addressed the question of what determines CBID. It would be desirable for investors to be motivated to bid the quantity of capacity honestly

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32 Vazquez, C., Battlle, C., Rivier, M., and Perez-Arriaga, I., (2003), *Security of Supply in the Dutch Electricity Market: the role of Reliability Options*, page 11.

33 Peter Cramton and Steven Stoft (2008), *Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency*, published in Utilities Policy, 16, 194-201, 2008 [emphasis added].

34 Peter Cramton and Steven Stoft (2008), *Forward Reliability Markets: Less Risk, Less Market Power, More Efficiency*, Utilities Policy, 16, 194-201, 2008, page 10. (Page number refers to offprint of article.)

35 Peter Cramton, Axel Ockenfels, and Steven Stoft, *Capacity Market Fundamentals*, 26 May 2013

because, for old plants and demand-side resources, they will have a more accurate view of its value than does the system operator. Also, investors will lobby to be allowed to determine CBID. However, as long as there is a significant amount of missing money, investors will want to set CBID as high as possible.

[…]

Typically, investors will want the highest possible $C_{BID}$, but what is the right $C_{BID}$ to assign them? This value should not inappropriately favor one type of generator over another; otherwise the market will select the wrong mix of capacity types. So $C_{BID}$ should be set so that the capacity market mimics a perfect energy-only market. This means that every MW of capacity should be paid the same on average as they would be paid by optimal scarcity prices, taking account of the fact that some generators are more reliable than others. If a generator is available twice as often during scarcity events, then it would receive twice as much peak revenue from an energy-only market. So it should also receive twice as much from a capacity market.

So, in order to properly reward capacity for its contribution to adequacy, it is necessary to set $C_{BID}$ to reflect the actual contribution of generating units to adequacy. (In a more complete model, we would find that $C_{BID}$ should reflect a generator's contribution to all scarcity events including those caused by security issues.) This means setting $C_{BID}$ equal to nameplate capacity times the probability that the unit will provide capacity during a scarcity event.

Another reason for the system operator to determine the capacity ratings to be used in the auction is to achieve consistency between the estimate of needed capacity and the amount of capacity purchased. For example, the system operator might find that a reliable market requires the 100 existing generators, with an estimated effective capacity of 30 GW, plus another gigawatt of new capacity. If generators determined their own $C_{BID}$ values, they would likely inflate them and when the auction bought 31 GW of capacity it would find this consisted of 90 of the existing generators and no new ones. At that point, 10 existing generators might retire and the system would become unreliable. Using the same capacity values for determining required capacity and for the purchase of capacity eliminates such discrepancies."[36]

145. Thus, these authors point out that generators and demand-side resources will tend to overstate the amount of reliable capacity they possess, and that the designers must set up (and hence the regulators must approve) a rule for designating a fair amount of capacity to each potential source.

- **C. Batlle, P. Mastropietro, P. Rodilla, I.J. Pérez-Arriaga (2014)**

146. A recent paper by a group of Spanish academics also highlights the need for ROs to be backed up by certification of capacity and penalties for non-delivery of capacity (in addition

[36] Peter Cramton, Axel Ockenfels, and Steven Stoft, *Capacity Market Fundamentals*, 26 May 2013, pages 10-11. (The omitted paragraph contains a technical discussion of problems in the treatment of demand-side resources, which is not relevant here.)

to the cost of making good the supply of energy).[37] The authors include Pablo Rodilla (whom the RAs invited to give a presentation at a recent workshop on the High Level Design) and Ignacio Pérez-Arriaga (until 2012 an Independent Member of the Irish Regulatory Committee for the Single Electricity Market). A short extract illustrates their support for a regulatory penalty in addition to settlement at the energy price:

> "The non-fulfilment of the contract commitments must be penalised by the regulator. The penalty should be high enough to dissuade the selected bidders to manage their generation plants for them not to accomplish their obligation. On the other hand, the penalty should not be excessive in case of prolonged technical unavailability." [38]

147. The authors identify the absence (or ineffectiveness) of such additional penalties in the Colombian system as a potential constraint on achieving a reliable supply of generation.

148. Thus, several authors, including those cited by the SEM Committee in the DDP, explain that ROs should be backed up by a system of capacity certification and penalties for under-performance, over and above the obligation to pay for an alternative supply of energy.

149. In the DDP, however, the SEM Committee refers to such arrangements only briefly, and as if they were an optional extra in ensuring that Reliability Options solve the missing money problem:

> "Pure reliability options do not have additional penalty mechanisms for non-delivery other than the amounts paid back when the RO is called. However, other markets have considered combining reliability options with penalties for physical non delivery. The requirement for these in the I-SEM context is not clear at this stage and this will be an issue to be considered in the detailed design of the mechanism.
>
> The eligibility rules will determine who can issue ROs, for example, whether option issuers will need to have physical plant capacity or a credible generation project, or what criteria demand side participants will be required to meet. The eligibility rules will also consider participation of cross border players and potentially demand providers. The eligibility rules will be determined as part of the detailed design of the mechanism."[39]

150. Despite these caveats, the SEM Committee refers to ROs throughout the DDP as "market-based", implying that they avoid the regulatory decisions required by other CRMs. In practice, as shown above, Reliability Options need arrangements linking them to the delivery of capacity to ensure that ROs solve the missing money problem. The need for such

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37 C. Batlle, P. Mastropietro, P. Rodilla, I.J. Pérez-Arriaga (2014), *The System Adequacy Problem: Lessons Learned From The American Continent*,IIT Working Paper, February 2014 version.

38 C. Batlle, P. Mastropietro, P. Rodilla, I.J. Pérez-Arriaga (2014), *The System Adequacy Problem: Lessons Learned From The American Continent*,IIT Working Paper, February 2014 version, pages 21-23.

39 DDP, paras 8.4.22 and 8.4.23.

regulatory arrangements undermines the SEM Committee's repeated claims that ROs are an entirely "market-based" solution to the missing money problem.[40]

151. The failure to consider these arrangements in this phase means the SEM Committee has not carried out a complete appraisal of the different CRMs (even at a high level). Instead, the SEM Committee's representation of the CRMs is selective, with the key regulatory features of Reliability Options being given little emphasis relative to the regulatory features of other CRMs. This mis-representation of ROs biases the SEM Committee's choice of CRM and leaves the draft decision without any basis for asserting that ROs will address the missing money problem. As a result, the draft decision to select ROs as the preferred form of CRM is unsound.

## 6.2. Inaccuracies in the Description of CRMs

152. Section 6.1 highlights a significant lack of detail in the SEM Committee's specification of ROs, but the problem extends to the SEM Committee's specification of other CRMs and hence to their evaluation.

153. The DDP maintains the distinction between "price based" and "quantity based" CRMs for the purpose of evaluating different kinds of CRM for the I-SEM. However, the distinction remains an artificial one, as we pointed out in our earlier report. Many of the assertions in the DDP about price based CRMs apply equally to the quantity based CRMs and vice versa, whilst some assertions apply only to extreme cases - which in practice means to none at all.

### 6.2.1. Definition of different types of CRM

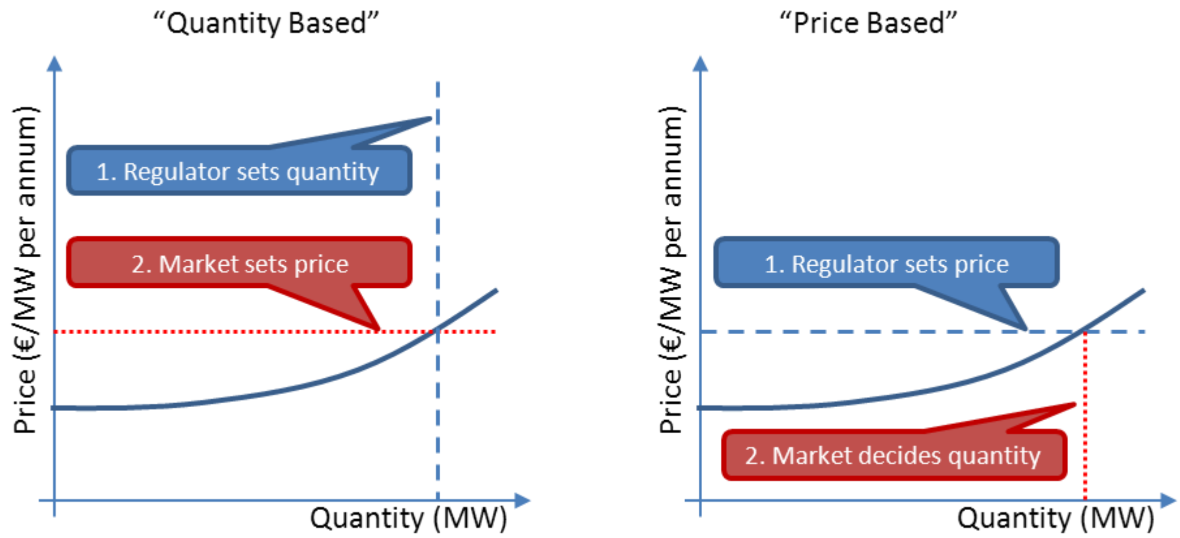
154. The SEM Committee defines a quantity based CRM as one where the regulator specifies the quantity of capacity required for supply adequacy and lets a market or auction define the price of that capacity.[41] Figure 1 shows such a scheme on the left hand side. The upward sloping curve represents the supply of capacity, showing what quantity is supplied at each price. The vertical dashed line represents the demand for capacity, defined by the regulator as a fixed quantity. The horizontal dotted line shows the price the market will set for supplying that quantity.

155. Similarly, the definition of a pure price based CRM would describe schemes where the regulator specifies a price for capacity and lets the market decide what quantity of capacity to offer at that price. The right hand side of Figure 1 shows such a scheme, with the same upward sloping supply curve. The horizontal dashed line represents the demand for capacity, defined by the regulator as a fixed price. The vertical dotted line shows what quantity the market will supply at that price.

[40] DDP, para 8.4.12 and passim.

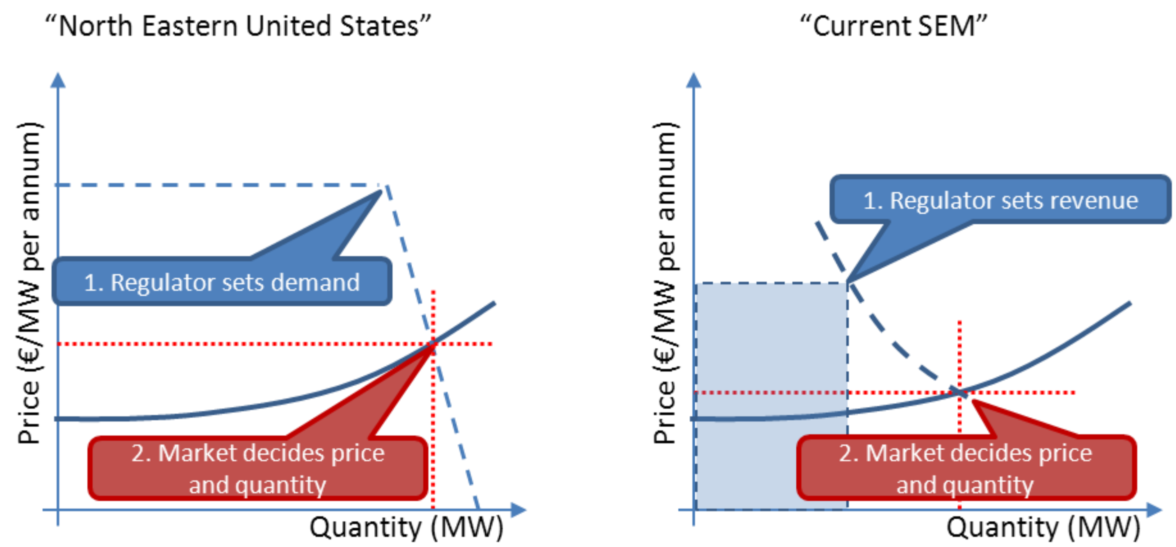
[41] DDP, para 8.4.2.

**Figure 1: Price and Quantity Based CRMs**




156. The schemes in Figure 1 represent extreme cases, where demand for capacity is either a vertical line or a horizontal line. In practice, many CRMs include a sloping demand curve, so that the buyer can call for more capacity if the price is low, and less capacity if the price is high. Figure 2 illustrates how these schemes work.

**Figure 2: CRM With A Sloping Demand Curve**




157. The left hand side of Figure 2 shows a stylised representation of capacity schemes operating in parts of the north eastern United States, where the regulator sets the parameters of a formal demand curve (the horizontal and sloping dashed lines) and the market chooses a price/quantity combination on that curve by reference to the supply curve.

158. The right hand side of Figure 2 shows a similarly stylised representation of the capacity scheme operating in the SEM at present. Here, the regulatory authorities set a total annual revenue for capacity, defined as a certain quantity multiplied by the annual cost of a new entrant and shown in the diagram as the area of the shaded rectangle. This annual revenue can be divided among different quantities of capacity, as represented by the curved dashed line (in practice, a demand curve with an elasticity of -1). The market then chooses a price/quantity combination on that curve by reference to the supply curve. The diagram in Figure 2 shows higher ("excess") capacity achieving a lower price per MW.

159. The schemes in Figure 2 represent intermediate cases, lying in between the vertical and horizontal demand curves shown in Figure 1. All of these schemes produce a result that adjusts to local conditions, by choosing a combination of price and quantity which reflects the cost and valuation of capacity.

160. Recognising the nature of these intermediate cases shows the incompleteness of the SEM Committee's description and appraisal of CRMs.

### 6.2.2. A brief note on "double payment"

161. When considering the introduction of a CRM, the designers sometimes ask whether it will lead to "double payment" of generators, i.e. if capacity will be remunerated twice over for the high value of electricity during peak periods – once in the energy market and once in the capacity market. In cases where the need for a CRM is based on the recognition of a "missing money" problem, however, such considerations no longer apply. The explicit purpose of a CRM is to provide a source of additional revenue, over and above the amount (whatever it is) that the energy market is expected to provide. In other words, if the CRM pays money which would otherwise be "missing", the question of double payment no longer applies.

### 6.2.3. Errors in the appraisal of CRMs

162. The DDP mentions only price based and quantity based CRMs. However, in the intermediate schemes in Figure 2, the regulator sets out different combinations of prices and quantities, as represented by the whole demand curve, whilst the market chooses to settle at one of those combinations of price and quantity.

163. The SEM Committee describes various schemes that employ a demand curve as "price based" and categorises its proposed Reliability Option scheme (CfDs bought through centralised auctions) as "quantity based".[42] In practice, centralised auction schemes (such as those in the north eastern United States) and payment mechanisms (such as the existing CRM in the SEM) both use demand curves to specify the different quantities of capacity that will be procured at different price levels. In the New England market, which operates ROs similar to the SEM Committee's proposed design, the market operator (ISO-NE) employs a demand curve with a fixed volume of capacity for some price levels, plus a price cap and a price floor

[42] "A price based capacity market employs a demand curve, i.e., a price that all suppliers will be paid based on an aggregate amount of eligible capacity." DDP, para 8.4.3.

(i.e. prices at which the level of capacity procured in the auction may vary). ISO-NE has recently filed a sloped demand curve for consideration by the Federal Energy Regulatory Commission (FERC) such that the volume of capacity procured by auction will vary with every change in the price between the cap and floor.[43]

164. The DDP not only describes all these intermediate cases as "price based", but also discusses them as if they were purely price based, with no adjustment to demand when prices rise above, or fall below, a certain level. That categorisation of these schemes is inaccurate.

165. Moreover, in many places, the SEM Committee makes statements about price based CRMs that would only be true for the price based scheme shown in Figure 1, where the regulator sets a fixed price. Many of these statements would not be true for CRMs classified by the SEM Committee as "price based" but where in fact the price and quantity can both vary along a sloping demand curve as in Figure 2. For instance, the SEM Committee argues that in "the price based scheme in the current SEM the value of capacity is largely based on a desktop study into the value of new capacity without a competitive market test".[44] However, the current scheme is an intermediate scheme, in which the calculation sets a total revenue and a demand curve determines the trade-off between the price of and quantity of capacity. Competition for the opportunity to supply capacity determines the price of capacity in such schemes, whether the price derives (directly or indirectly) from a regulatory calculation, as in the current SEM, or is set by centralised auction, as in the proposed RO.

166. The SEM Committee also states that, in a quantity based scheme, "the market determines the price and technology of capacity and the regulator determines the one thing that the market has no information on, that is the level of capacity adequacy that is socially optimal".[45] This argument ignores the information problems facing both sides. The market may have better information about the technology and its costs and be unable to decide the optimal level of capacity, but the regulator has to determine the optimal level of capacity with limited information about the cost of capacity for each technology. In the case of intermediate schemes of the kind that markets actually implement, the regulator does not determine "the" optimal level of capacity, but rather a demand curve of different optimal capacities at different prices. Essentially, it sets out the regulator's view of the marginal benefit of capacity to society at every level of security, so that – whatever the cost turns out to be – the market procures an amount of capacity that is close to the efficient level.

167. The SEM Committee's evaluation of CRMs of the type shown in Figure 2 is therefore influenced – and biased – by emphasising the inflexibility and potential problems associated with the purely price based scheme shown in Figure 1. Many of these statements would not apply to intermediate (price/quantity) schemes, including the SEM's current CRM.

168. The SEM Committee has therefore mischaracterised many CRMs and/or criticised price based schemes for possessing fixed price characteristics that do not exist in reality. This error

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43 *Motion To Intevene And Protest Of The New England Power Generators Association, Inc. And Electric Power Supply Association before the Federal Energy Regulatory Commission*, 1 April 2014.

44 DDP, para 8.4.6.

45 DDP, para 8.4.6.

has biased the SEM Committee's evaluation of CRMs and distorted its final choice. The draft decision is not therefore soundly based.

## 6.3. Faulty Reasoning Behind the SEM Committee's Decision

169. The SEM Committee concludes in favour of ROs for a number of reasons based on application of the high-level principles used in the Initial Impact Assessment. However, the CRMs are not sufficiently well-specified to allow a proper evaluation and the criteria have been applied in a selective and biased manner. As a result, the evidence provided in the IIA does not provide a sound basis for the SEM Committee's draft decision.

170. Below, we discuss key sections in the appraisal, relating in particular to the reasons given for choosing a "quantity based scheme" over a "price based scheme", and how the text betrays a lack of understanding or subjective and ill-informed choices.

- **Reason 1: "A quantity based scheme will provide a more competitive market based solution for the valuation of capacity than a price based scheme".[46]**

171. As explained above, the distinction between quantity based and price based schemes is blurred by the adoption of sloping demand curves, so that neither is more "market based" than the other. Higher prices for capacity lead to a lower quantity being demanded, and vice versa. Even schemes in which the regulator nominally fixes a quantity or a price will face pressure for similar adjustments, albeit on an *ad hoc* basis rather than through a formula. As a result, there is less difference between the outcomes generated by each scheme that the DDP implies.

172. Moreover, the DDP applies appraisal criteria without defining complex terms such as "more competitive". The comment above seems to apply to competitiveness in the *process* of allocating capacity revenues, rather than to the competitiveness of the supply-side structure of the market (which is broadly unaffected by the choice of scheme). If so, this statement fails to recognise the different ways in which competition takes place. In quantity based schemes, generators compete to set the price of capacity. (See Figure 1.) However, in price-based schemes (which include the current CRM in the SEM, according to the DDP), generators compete for a share of the total annual revenue awarded by the regulator. In both types of CRM, only those with the lowest cost capacity (existing or new) will remain in the market over the long-term. Both types of CRM will therefore encourage efficient exit – i.e. the exit of the capacity with the highest costs of remaining in operation.

173. Thus, it is not possible to make firm statements about the competitiveness or other performance outcomes of different schemes (especially real schemes) without (a) defining how performance is measured and (b) focusing on the detailed rules of each scheme.

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[46] DDP, para 8.4.6.

- **Reason 2: A quantity based scheme "should provide a more proportionate response than a price based scheme to the issues being addressed".[47]**

174. Here, the SEM Committee may be relying on statements in the EU State Aid Guidelines, but in practice there is no analytical basis for this statement. As discussed above, the boundary between price based and quantity based schemes is blurred, to the point where adding a demand curve leads each type to achieve broadly the same outcome in terms of security (quantity of capacity) and efficiency (price of capacity). Therefore, there is no *a priori* basis in theory for this kind of subjective statement about proportionality, and no basis in fact.

- **Reason 3: "a quantity based scheme can be designed more appropriately than price based schemes to mitigate against undue cross border trade distortions".[48]**

175. Although we can see why the SEM Committee might possibly have reached this conclusion, it is not necessarily true and cannot be supported without a detailed consideration of each scheme, which the DDP and IIA lack.

176. The assumption that lay behind the SEM Committee's conclusion may have been that fixing different prices for capacity in neighbouring countries would cause market participants to choose inefficient patterns of flow over interconnectors. In fact, a well-designed capacity payment would have little or no effect on flows (just as it should have little or no effect on the pattern of generation). At peak times, the prospect of earning higher capacity payments might conceivably cause market participants to send electricity from a market with a high energy price to a market with a low energy price. That would represent inefficient arbitrage. However, as discussed elsewhere in this report, the effect on efficiency of generation and consumption would depend on the interventions of the TSOs, not on the inefficiency of arbitrage.

177. Furthermore, pure quantity based schemes may be more prone to abuse by dominant players – and might conceivably cause even more distortion of cross border flows. Experience in the United States shows that the price of capacity in a quantity based CRM is sensitive to generators withholding capacity (or increasing the supply of capacity and demand-side resources). The price of capacity in a pure price based schemes cannot be manipulated in this way and might cause less distortion of cross-border trade.

178. In practice, of course, any scheme will comprise a demand curve (a price-quantity trade-off) and some measures to mitigate market power (such as price caps and floors). Any appraisal of a CRM would have to take these features into account. However, the SEM Committee has failed to specify such features at this stage for most of the CRMs it evaluated. Its evaluation of CRMs is therefore partial and selective.

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[47] DDP, para 8.4.7.

[48] DDP, para 8.4.8.

- **Reason 4: "as discussed previously and as mentioned by respondents, the requirement for more flexibility in the generation fleet is an important issue which is linked to RES targets and meeting security of supply standards at least cost to consumers".[49]**

179. This reason does not seem to apply to the choice between quantity based and price based schemes, but rather to the definition of eligible capacity. (See for example Batlle et al (2014), pages18-21, on defining the length of the "critical period" over which capacity is measured and provided.) The need to define capacity is common to all the CRMs discussed by the SEM Committee. This "reason" therefore provides no basis for preferring one CRM over another.

- **Reason 5: "the EC and ACER have written on different CRM designs in the last number of years as the issue has gained prominence".[50]**

180. This text does not seem to provide any reason for making a choice.

181. Thus, the DDP and IIA offer no firm reasoning in favour of choosing a quantity based scheme over a price based scheme or one with a demand curve. Overall, the SEM Committee has not provided any objective or convincing reasons for selecting its chosen form of CRM and rejecting others.

## 6.4. Tendency to Overlook Adverse Effects of ROs

182. The SEM Committee's evaluation of CRMs does not consider several important possible adverse effects of the ROs and how the design would have to be adjusted to reflect these effects. The effects and/or the mitigating features of the design would affect the evaluation of the different CRMs and might have changed the SEM Committee's decision. Their omission is therefore significant.

### 6.4.1. Contracting and liquidity

183. First, ROs will overlap with some of the hedging that would normally be provided by energy contracts (CfDs). ROs will offer a hedge against market prices above the RO Strike Price.

- To avoid over-compensating for market price risks, market participants will have to design CfDs that only hedge market prices up to the RO Strike Price. (Criterion (4)) This may be a minor inconvenience for new contracts, but will impose costs on holders of existing contracts. It also means that the RO Strike Price should be clearly defined to allow transparent design of CfDs. For example, it might be indexed to the fuel price component of the variable cost of the most expensive generator within the I-SEM (although that is only one rule among many equally transparent rules).

[49] DDP, para 8.4.9.

[50] DDP, para 8.4.10.

- Setting multiple RO Strike Prices would reduce transparency and segment the CfD market (and would in any case greatly increase the complexity and subjectivity of regulatory decisions on design of the RO).

184. Second, as discussed above, ROs will only hedge consumers against the risk of very high prices if the disbursement of RO rebates is closely coordinated with tariff design. A perfect hedge would require each customer's retail tariff to be tied directly to the DAM price, so that the RO rebate offsets rises in the tariff exactly. If tariffs are set competitively but are not indexed to the DAM price, they may remain stable for long periods (as at present). If RO rebates are passed through to consumers as the events occur, the rebates will – perversely – reduce customer bills and industry revenue during a capacity shortage, a position which may not be sustainable. On the other hand, competitive markets may price in the *anticipated* rebate, rather than pass them through as the events occur. Depending on the design of the ROs any rebates may be returned to consumers as a group, but may be distributed in a manner that customers and regulators regard as inequitable. Accordingly, it is not clear that ROs would remove the incentive for regulatory intervention in periods of high prices and therefore solve the missing money problem.

### 6.4.2. Impact on generator risk

185. ROs will only provide a tool for managing generators' risks if generators can expect to be generating the same volume as their ROs at peak times when the ROs are called and rebates must be paid. (Criterion (4)) The articles by Cramton and Stoft discuss how the capacity each generator can offer ($C_{BID}$) should be adjusted for their observed or expected reliability. However, the use of Euphemia creates an additional source of scheduling risk, as discussed elsewhere in this report. Generators may be unable to ensure that they are generating a peak times, because they are unable to configure their offers to achieve the necessary pattern of output, and not because they are technically unable to provide capacity. (Criterion (9)) Such risks would unnecessarily increase the cost of generating (and hence prices to consumers) within the I-SEM with ROs as specified in the DDP.

### 6.4.3. Selection of a reference price from the Day-Ahead Market:

186. The SEM Committee is proposing to decide the reference price used to settle ROs in the detailed design phase,[51] but the selection of Option 3 strongly suggests that it would be taken from the Day-Ahead Market.[52] However, actual capacity shortages may not be predictable at the day-ahead stage. Prices in the DAM may therefore lie sometimes above and sometimes below the real time value of electricity on the following day. The scheme in Colombia works this way, but the RAs have not considered the impact of using a day-ahead reference price in the conditions pertaining in the I-SEM. It raises the following questions.

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[51] DDP, paragraph 8.4.17.

[52] See for example DDP paragraph 6.3.35 on Option 3, which links " a high degree of liquidity and transparency in the DAM" to the creation of "a robust reference price". See also DDP paragraph 6.4.27, where the SEM Committee states its view that "Other aspects of the market rules will be developed to encourage participation in the DAM…such as setting the DA price as the strike price for directed contracts and as the reference price for financial reliability options". DDP paragraph 8.4.20 and IIA paragraph 7.2.24 acknowledge the possibility of choosing an intra-day or balancing price instead.

- Will the price in the DAM ever be unable to reflect the true (expected) value of electricity on the following day, because of the price cap in Euphemia of €3,000/MWh? If so, will the ROs solve the missing money problem? (Criterion (2))
- Because of the difficulty of predicting actual shortages, tying ROs to the DAM will sometimes trigger rebates when no shortage occurs. The DAM may also fail to trigger rebates when a shortage does occur. These rebates will flow through to suppliers and, perhaps, directly into consumer bills. A full appraisal of ROs would include consideration of the implications of these mismatches between prices, costs, tariffs and revenues, for generator cash flows and consumer bills, to see if they affect investment incentives and future security of supply. (Criterion (4))
- Selecting the DAM as the reference price seems to be driven by a desire to promote day-ahead trading (rather than any specific concern for security of supply or efficiency). However, participation in the DAM may not be mandatory. A full appraisal of ROs would consider whether the price cap of €3,000/MWh in the DAM will sometimes drive the supply of generation into the (uncapped) ID and BM markets. This development would affect the risk-hedging properties of the ROs for generators, suppliers and consumers. (Criterion (4))

187. These omissions mean that the SEM Committee cannot claim to have properly evaluated the ROs (relative to other CRMs).

### 6.4.4. Market Power Mitigation

188. Any full appraisal would consider how the RAs will mitigate market power in the auctions for CRMs (and for Reliability Options in particular). For example, ISO-NE, the system operator in New England, operates under strict regulation of offers into its capacity auction. This auction has a floor price and rules on minimum levels of competition – despite being substantially larger (around 36GW) than the SEM. (Criterion (12))

189. These restrictions on pricing in a capacity auction illustrate once more why the distinction between quantity based and price based schemes is a false one, that should play little part in the IIA. It also shows that market mitigation rules can have a major effect on outcomes under any scheme, and would be taken into account in any full appraisal of CRMs. (See chapter 7 for more on this topic.)

### 6.4.5. Small size of market

190. Due to the small size of the market in the SEM, the price of ROs may still be volatile if investors can anticipate a shortage/surplus of capacity in the year for which ROs are being auctioned. Under current proposals, ROs would be auctioned up to 5 years ahead, but the situation in that year may well be predictable in the SEM, due to the impact of individual no-go investment decisions on a small market.

191. The DDP mentions a reduction in the minimum efficient size of new investment,[53] but that phenomenon seems to apply mainly to renewable energy projects. In that case, the size of

[53] DDP, paragraph 7.4.12.

individual projects is less important than the total response to changes in renewable energy policy. The price of ROs may still be volatile if market participants anticipate waves of investment in renewable energy starting or stopping, following a change in state-sponsored incentives. In any case, the DDP acknowledges that exit decisions (concerning the existing thermal generation plant) would still have a significant effect on security of supply (and hence on the value of capacity).[54]

192. The purpose of the current scheme was to stabilise revenues in the anticipation of such volatility in energy prices, as a contribution to avoiding the missing money problem. (Criterion (2)) However, the DDP and IIA do not consider whether ROs or any form or CRM will actually achieve that aim, which represents a major omission from the appraisal.

## 6.5. Conclusion

193. We conclude that the SEM Committee has not justified its proposed decision to select Reliability Options because:

- the SEM Committee has left out significant details from the proposed design of the RO, even though those details are crucial to achieving the RO's intended purpose, so that its evaluation of the RO is *incomplete*;
- the SEM Committee has taken a *selective* approach to describing the effects of each design, specifically by overlooking possible adverse effects of the proposed RO; and
- the SEM Committee has evaluated possible designs for a CRM against criteria that vary from case to case, in scope and in definition, introducing a *bias* into the appraisal and preventing a fair, like-for-like evaluation of the designs.

194. Because of these flaws in the appraisal of the various CRMs, the SEM Committee's choice is not soundly based.

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[54] DDP, paragraph 7.4.12.

# 7. Market Power Mitigation

195. The measures required to mitigate or prevent abuses of market power represent another area which remains to be specified, and which could overturn the SEM Committee's decision.

## 7.1. Market Power Mitigation in Energy Trading

### 7.1.1. The need for market power mitigation

196. When the SEM was established in 2007, ESB's large market share caused major concern and led to the establishment of the Bidding Code Of Practice (BCOP). The BCOP obliges generators to submit offer prices that reflect their Short Run Marginal Costs (SRMC), as defined by the opportunity cost of their inputs. Since 2007, the RAs have also directed large generator firms to maintain a portfolio of "directed contracts", i.e. contracts sold off compulsorily by auction, in order to limit their ability to benefit from changing spot prices.

197. In 2010, CEPA studied the state of competition in the SEM at the time and in years to come. In its report,[55] CEPA recommended that the Bidding Code of Practice and directed contracts should remain in force, due to continuing concerns about competition in generation. The SEM Committee accepted CEPA's recommendations in 2012, in the course of approving a horizontal re-integration of two generation businesses owned by ESB.[56]

198. CEPA noted that additional generation had entered the SEM since 2007, and that interconnector capacity had been expanded. However, looking to the future, CEPA found that in many hours ESB would still be "pivotal" – that is. output from its generators would still be required to meet the current level of demand, even if every other generator was operating at full output.[57] A number of these hours arose in the future because output from wind farms will fall to low levels, creating a shortage of capacity, due to natural variation in their output.

199. CEPA also noted that ESB would be pivotal more often, if electricity prices were higher in Great Britain than in the SEM, as the additional interconnector exports from the I-SEM to the British market would then raise demand on generation resources in the SEM, instead of providing a competitive substitute for them.[58]

200. In passing, CEPA also noted that the incentive for generators to withdraw contracts was undermined both by the directed contracts and by the potential loss of a capacity payment. However, CEPA concluded that, in the absence of any major structural changes in the

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55 CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010.

56 SEM Committee (2012a) *SEM Market Power & Liquidity, A SEM Committee Decision Paper*, SEM-12-002, 1 February 2012.

57 CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010, page 26.

58 CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010, page 28.

concentration of generation, it would still be "appropriate" to retain the BCOP and the directed contracts.[59]

201. Thus, as recently as 2010-12, CEP A and the SEM Committee accepted the need to retain the BCOP and directed contracts in order to mitigate market power. They reached this conclusion despite the entry of competing generators and the increase in interconnector capacity since 2007. They noted that interconnector capacity was not a reliable source of competition because it would add to demand rather than supply, if it flowed from Ireland to Britain at peak times. CEPA also noted that the current capacity payment provided an additional disincentive to the withdrawal of capacity, which would be lost of the capacity payment were abolished.

### 7.1.2. Market power mitigation in the DDP and IIA

202. The DDP and IIA accept at various points that some measures to mitigate market power will be required. The DDP notes that applying the BCOP will be more difficult – or even impossible – under Option 3, because the structure of offers and bids will not be tied closely to costs. The DDP concludes that the BCOP is unlikely to be maintained, at least in its current form. It says that some ex ante monitoring may be needed, but does not propose any detailed alternative.[60]

203. Under some of the Options, the BCOP may have to be replaced by other measures, but that should count as an adverse effect of choosing those Options. The DDP notes the benefits of transparency in mitigating market power abuse,[61] but does not use this observation in appraising the Options. (We record it as Criterion (12).) Ex ante regulation and/or ex post scrutiny offer an alternative to the BCOP, but neither will ever be as transparent or effective as the BCOP applied to a gross pool with a complex offer price structure. Without such transparent rules, there is no objective way to identify the source of market abuses because there is no way to apportion blame to an individual market participant responsible for market abuses. Oligopolistic competition drives all market participants eventually to adopt similar pricing policies. All market participants will end up exercising market power, but not all such behaviour may constitute an abuse. Competitive pressure may drive small, non-dominant companies to raise their prices just so they match the price of a larger company, or of a market leader. In such circumstances, it may not beclear who is abusing market power (if anyone).

204. The difficulty is well summarised in Wolak (2005), commenting on the attempt by Ofgem in 1999/2000 to introduce a prohibition on market abuse into generator licences.[62] In that paper, he summarises the difficulty as follows:

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[59] CEPA (2010), *Market Power and Liquidity in SEM; a report for the CER and the Utility Regulator*, Cambridge Economic Policy Associates Ltd, 15 December 2010, page 28.

[60] DDP, paragraph 6.4.63.

[61] DDP. Paragraph 5.4.4.

[62] Frank A. Wolak (2005), *Lessons from International Experience with Electricity Market Monitoring*, Department of Economics, Stanford University, 11 July 2005 (available at http://web.stanford.edu/group/fwolak/cgi-bin/?q=node/3)

> "Although a license provision prohibiting abuse of market power appeared to be an effective mechanism for limiting the exercise of market power, the difficulty Ofgem ran into was how to distinguish the unilateral exercise of market power from abuse of market power. It was never able to find a satisfactory way to make this distinction, and many economists including Wolak (2000) [and one of the authors of this report] provided comments stating that this was not possible in a manner that did not introduce significant market inefficiencies."[63]

205. Wolak's point is that, in an oligopolistic electricity sector, it is impossible to identify who is responsible for abusing a market by observing the behaviour of individual companies. Under the SEM at present, the BCOP holds each company is held to a well-defined standard of pricing. Wolak's comments suggest that moving away from the BCOP, as would be required under Option 3, runs the risk of introducing "significant market inefficiencies". Options 2 and 4 contain a pool and would retain the current complex offer price structure. They would allow the RAs and market participants to apply the BCOP in its current form.[64] However, Options 1 and 3 will require the RAs to control market power by adopting alternative measures or by expanding the other measures used at present, e.g. by increasing the volume of directed contracts. We would have expected to see this difference recognised as a disadvantage of Option 3 and an advantage of Options 2 and 4. However, at no point do the DDP or the IIA recognise the resulting advantage over Option 3 offered by Options 2 and 4, either with respect to efficiency (Criterion (2)) or with respect to the transparency of market power mitigation measures (Criterion (12)).

### 7.1.3. Summary

206. The SEM Committee has reached a draft decision to adopt Option 3, whilst recognising that it will make the BCOP unworkable, without explaining how it will overcome this problem. The DDP and IIA should have identified as a consequence of adopting Option 3 the need to adopt alternative measures for market power mitigation – or to expand other measures already in place, such as directed contracts. This difficulty ought then to have counted against Option 3, relative to Options 2 and 4, but the DDP simply assumes that it will solve the problem in the detailed design phase. The SEM Committee's approach is subjective and prejudicial, and is neither evidence-based nor a sound basis for regulatory decisions.

## 7.2. Market Power Mitigation in CRMs

### 7.2.1. The need for market power mitigation

207. Market power in a capacity market is related to market power in the energy market. Generators who control a significant proportion of the capacity on the system are likely to have market power in both parts of the electricity market. A small market with a large incumbent player, like the Irish market, will require market power mitigation mechanisms in both the energy market and the capacity market. Failing to spell out these mechanisms in

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63 Frank A. Wolak (2005), pages 10-11 (Stanford University website version).

64 DDP, paragraph 6.3.47.

advance would run counter to the need for transparency in market power mitigation. (Criterion (12))

208. In fact, the need for market power mitigation may be greater in the capacity market than in the energy market, since the value of capacity is so concentrated in peak periods and is so sensitive to small changes in available capacity. The SEM Committee has argued that the growth in interconnectors in recent years has diversified the sources of electricity supply and reduced the market power problem in Ireland.[65] In relation to the energy market we have already identified issues with this assumption in paragraphs 196 to 201 above. In a CRM, however, the SEM Committee cannot rely on interconnectors to be contributing to supply in peak periods, as they may be exporting to Britain at times of system stress. The risk that interconnectors make no contribution to security of supply at times of system stress is exacerbated by the strength of the penalties imposed at such times for not generating in the British market. The current, and seemingly final, proposals for the British market impose a penalty rate of 1/24$^{th}$ of the market clearing price in the capacity auctions. At DECC's projections of clearing prices around £30/kW, the penalty rate would be £1,250 during a stress event.[66]

209. Possible responses to the reduced reliability of interconnector capacity include reducing, or eliminating, its capacity rating in the centralised auction, which would lessen competition in the CRM compared to the energy market and increase the need for market power mitigation in the capacity market.

210. The specific design selected by the SEM Committee in the DDP needs some market power mitigation. A single, centralised auction provides sufficient opportunities for abusing market rules, as well as for signalling between participants, to merit concern about market power. Accordingly, many similar mechanisms in the United States and the market design for the proposed 2014 capacity auction in Britain include market power mitigation rules which seek to prevent gaming by participants. The designers of US mechanisms take a variety of approaches to mitigating market power, but the following selection shows the kind of rules they have put in place:

- **Minimum Offer Price Rules (MOPR):** In the New England market, bidders may not bid below the Minimum Offer Price and the market monitor scrutinises bids to make sure that buyers are not distorting the market by exerting downward pressure on prices.[67]
- **Insufficient Competition Rules:** The New England market replaces competition with an administrative process if new supplies are needed in a capacity zone and if any market player is pivotal or if offers from new generation amount to less than 300MW or less than twice the new generation required.[68]

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[65] DDP, paragraph 8.4.7.

[66] DECC(2014), *"Electricity Market Reform: Capacity Market – Consultation on Proposals for Implementation: Government Response", June 2014,* pages 96-97.

[67] ISO-NE, Market Rule 1, Section, III.13.1.1.2.8, Qualification Determination Notification for New Generating Capacity Resources. [Downloaded 14 July 2014].

[68] ISO-NE, Market Rule 1, Section III.13.2.8.2. Insufficient Competition. [Downloaded 14 July 2014].

- **Resource-Specific Sell Offer Requirements:** Both New England and PJM have strict price caps applied to resources which may be able to exert market power. In PJM, any market participant who satisfies a "three-bidder pivotality" criterion (such that the market could not clear without the capacity belonging to that market participant and two other bidders) may not bid above a strict price cap.[69]

211. Versions of these rules have been adopted in the British market. In Britain, new generators and demand resources automatically qualify as price makers, and may bid in the auction for annual capacity contracts up to a price cap of £75/kW, which represents 1.5 times DECC's estimate of the net cost of new entry. Existing generators may not bid above £25/kW unless they can demonstrate that their costs require them to obtain a price above that level, or else they will close their plant. The capacity markets in the US and in Britain are much larger than the equivalent market in Ireland. Peak demand, for instance, is over 150 GW in the PJM and about 54 GW in Britain; these figures are about 21 times and 8 times, respectively, the level of peak demand in the Irish market, which is only about 7 GW.[70] Withdrawal of a single plant is therefore more likely to move the market price in Ireland than in these other markets, and the fears about a dominant player have not been eliminated since 2007. Consequently, in the Irish context, any centralised auction for Reliability Options will require similar, or perhaps more stringent, market power mitigation mechanisms.

### 7.2.2. Market power mitigation in the DDP and IIA

212. The SEM Committee argues that the proposed form of Reliability Options will rely on competition as the engine that minimises the cost to consumers. The DDP, which summarises the results of the qualitative impact assessment, claims that Reliability Options provide a:

> "transparent centralised platform for competition that facilitates efficient and coordinated entry and exit signals, whilst using competitive pressures to ensure that consumers don't overpay for adequacy. Centralised reliability options fit well with possible market power mitigation measures in the energy market."[71]

213. It is not clear what is meant by "fitting well" with measures in the energy market. In practice, as discussed in section 7.2.1 above, centralised auctions in the electricity sector tend to be closely scrutinised and run as regulated procurement processes. In the IIA, the SEM Committee discusses competition for CRMs in paragraphs 7.5.40-7.5.45. The discussion betrays an unfortunate degree of selectivity in the appraisal of each CRM.

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69 PJM Manual 18: PJM Capacity Market Section 5: RPM Auctions, Rule 5.3.1.

70 PJM (2014), *Peak Demand Forecast Report January 2014*, page 3. Ofgem (2014), *Electricity Capacity Assessment Report 2014*, 30 June 2014, Figure 2 on page 12. SONI and EirGrid (2014), *All-Island Generation Capacity Statement: 2014-2023,* Table A-1 on page 61.

71 DDP, Table entitled "Summary of qualitative rationale for centralised reliability options against each assessment criteria", underneath para 8.5.2.

214. Paragraphs 7.5.40-41 highlight the problems with short-term price-based CRMs. However, the criticisms raised here apply equally to short-term quantity-based CRMs, a point which the SEM Committee omits. Experience of short-term capacity obligations in the PJM led to the adoption of the current, longer-term scheme.

215. Paragraphs 7.5.42 identifies a feature of the current scheme, namely that the exercise of market power cannot affect total payments in the long run. However, the SEM Committee seems to make nothing of this advantage in its evaluation of CRMs.

216. This oversight stands out particularly starkly, given that the SEM Committee recognises in paragraphs 7.5.43-45 the need for market power mitigation mechanisms to ensure that Reliability Options work effectively:

> "For the quantity-based CRMs (Options 3, 4 and 5), the key area of competition is for the contract award in the form of the initial auction. Given the potential in a small market for anticompetitive behaviour, market power mitigation measures may be needed as part of the detailed auction design.
>
> Market power mitigation measures are part of quantity-based CRMs in other markets, e.g. in the US and in the proposed GB scheme. This can include bidding rules, which can relate to minimum offer prices to deter inefficient exit or maximum bids (e.g., for existing plant). These rules could also be targeted at a subset of the market where market power has been identified as a concern.
>
> Crucially, centralised reliability options offer a transparent public auction that is held on behalf of all demand in the market so as to exploit economies of scale (th[r]ough the concentration of liquidity) with the objective of increasing competition, and creating a level playing field for market participants. International best practice and experience strongly argues for a centralised auction process on competition promotion and market power mitigation grounds"[72]

217. The IIA does not claim that Reliability Options are immune to the market power problems encountered in other "quantity based" capacity auctions. However, the DDP does not reflect the concerns about market power and quantity based CRMs set out at this point in the IIA. The DDP provides no description of market power mitigation mechanisms in the market for Reliability Options, leaving such matters entirely to the detailed design phase.[73] Instead, the DDP conveys the impression that Reliability Options operated through centralised auctions are transparent and competitive. The DDP notes that transparency fosters competition, but that finding is not always supported by economic theory or practice. Many centralised auction processes deliberately hide information about the current set of bids from participants to prevent anticompetitive behaviour. For example, the capacity market rules for Britain mandate a descending clock auction in which market participants only receive limited information about the bidding process. The auctioneer will not reveal the identity of the remaining bidders during the bidding process and will round the volume of excess supply at

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72 IIA, paras 7.5.43-45 (Footnotes omitted).

73 DDP, paragraph 8.4.23.

any given price to the nearest GW.[74] These rules are intended to prevent transparency from becoming an aid to tacit collusion.

### 7.2.3. Summary

218. In summary, the SEM Committee adopts different views in the DDP from those expressed in the IIA. The DDP repeatedly describes Reliability Options as "market-based" and implies that the process of awarded and managing them will be solved by transparent auctions. The IIA, on the other hand, notes that conduct of an auction will require a major regulatory intervention to mitigate market power.

219. These conflicting approaches betray a fundamental confusion about the implications of Reliability Options for competition. If the regulator has to tell major market participants what to bid, the outcome of a centralised auction for Reliability Options will not be a product of competition, but rather the outcome of regulatory decisions about key parameters. The DDP is therefore misleading, because it contrasts "market-based" Reliability Options with other CRMs that are supposedly more heavily regulated. In practice, international practice shows that none of the auction-based mechanisms operate without significant regulatory intervention to constrain bidding behaviour.

220. Any regulatory intervention intended to counter market power in a competitive market runs the risk of adverse effects, because it may also distort or prevent pro-competitive bidding behaviour. No impact assessment would be complete unless it examined the regulatory interventions required by each kind of CRM and assessed the associated risks of adverse effects. By overlooking the need for regulatory interventions in auctions of Reliability Options, whilst recognising that need for other CRMs, the SEM Committee has biased its evaluation of the different mechanisms.

## 7.3. Conclusion

221. Nothing suggests that market power problems have been eliminated since 2007, or will be eliminated in the near future. However, according to the RAs, it will be safe to abandon the current BCOP, despite not knowing what will replace it under Option 3. We conclude that the SEM Committee's willingness to abandon the BCOP represents a subjective leap of faith, or a prejudicial bias in favour of Option 3, rather than a conclusion based on evidence, and that the SEM Committee should consider what alternative measures or expanded measures (such as a greater volume of directed contracts) would be made necessary by the adoption of Option 3.

222. Measures to mitigate market power are also likely to be necessary in any centralised auction of capacity market instruments in the I-SEM. The SEM Committee recognises this need in the IIA, but ignores it in the DDP, frequently describing Reliability Options as "market-based",[75] whilst highlighting the degree of regulatory intervention in other CRMs. This

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74 *The Capacity Market Rules 2014*, chapter 5, rule 5.5.18, page 55.

75 See DDP, 1st paragraph on page 12, paragraph 8.4.12 on page 73, and also Decision 4 ("The I-SEM CRM will be based on Reliability Options") on pages 14 and 76 of the DDP.

selectivity in describing the impact of market power mitigation has biased the SEM Committee's evaluation of CRMs for the I-SEM. As a result, we conclude that the SEM Committee has no reliable basis for assessing CRMs, or for selecting Reliability Options, with regard to their impact on competition.

## 8. Summary of Conclusions

223. Overall, we conclude that no-one can have any confidence that the SEM Committee has reached the right decision on High Level Design for the I-SEM. (Chapter 2)

224. In relation to the methods of appraisal used in the DDP and IIA, we conclude:

- that the decision to select Option 3 is not based on a full understanding of its implications and is biased by the focus on a limited set of each Option's features (Chapter 3); and
- that the SEM Committee's appraisal of the Options and Capacity Remuneration Mechanisms is not based on equal application of objectively defined criteria, but on the selective use of subjectively defined criteria and *ad hoc* considerations. (Chapter 4)

225. With regard to the selection of energy trading arrangements (Chapter 5), we conclude:

- that the SEM Committee's description of the Options is incomplete and in some cases erroneous;
- that SEM Committee's appraisal of the Options is selective, subjective and prejudiced; and
- that the SEM Committee's draft decision is not soundly based on evidence or analysis.

226. With regard to the selection of a Capacity Remuneration Mechanism (Chapter 6) , we conclude that the SEM Committee has not justified its proposed decision to select Reliability Options because:

- the SEM Committee has left out significant details from the proposed design of the RO, even though those details are crucial to achieving the RO's intended purpose, so that its evaluation of the RO is *incomplete*;
- the SEM Committee has taken a *selective* approach to describing the effects of each design, specifically by overlooking possible adverse effects of the proposed RO; and
- the SEM Committee has evaluated possible designs for a CRM against criteria that vary from case to case, in scope and in definition, introducing a *bias* into the appraisal and preventing a fair, like-for-like evaluation of the designs.

227. In relation to market power within energy trading (Chapter 7), we conclude that the SEM Committee's willingness to abandon the BCOP represents a subjective leap of faith, or a prejudicial bias in favour of Option 3, rather than a conclusion based on evidence, and that the SEM Committee should consider what alternative measures or expanded measures (such as a greater volume of directed contracts) would be made necessary by the adoption of Option 3.

228. In relation to market power within the capacity market (Chapter 7), we conclude that the SEM Committee has no reliable basis for assessing CRMs, or for selecting Reliability Options, with regard to their impact on competition.

229. We therefore conclude that the SEM Committee's draft decision on a High Level Design for the Single Electricity Market is unsound.

# Appendix A. EU Target Model – Key Elements

230. The following elements of the EU Target Model, as encapsulated in ACER guidelines, are the most relevant to the SEM Committee's consideration of a new High Level Design for the SEM.

## A.1. Market Coupling

231. The *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity* ("CACM Guidelines") issued by ACER in 2011 require market coupling at the day-ahead stage. The phrase "market coupling" means that cross-border transmission capacity is made available at the day-ahead stage all across Europe "implicitly" through trades arranged on power exchanges, rather than being explicitly auctioned as transmission capacity between two networks in neighbouring countries.[76]

## A.2. Cross-Border Transmission Contracts

232. ACER's CACM Guidelines also require that market participants have access to option contracts for cross-border risk hedging.[77] These option contracts may in principle be Financial Transmission Rights (FTRs) or Physical Transmission Rights (PTRs), as long as any PTRs are subject to Use-It-Or-Sell-It (UIOSI) provisions. The NRAs in the two countries concerned may decide which method to adopt, but may not mix the two methods "on the same border". They must auction off any cross-border rights using a common European or regional platform. In practice, since any implicit auction of cross-border transmission capacity includes a physical constraint (either ATC or "flow-based"[78]), there is very little difference between (1) auctions of energy plus uncommitted capacity covered by FTRs and (2) auctions of energy plus PTRs released under the UIOSI rule.

## A.3. Gate Closure

233. The CACM Guidelines also foresee an intra-day market that enables market participants to trade energy as close to real-time as possible, through implicit auctions where feasible.[79]

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[76] ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 3.1, page 9: "The CACM Network Code(s) shall foresee [i.e. provide] that TSOs implement capacity allocation in the dayahead market on the basis of implicit auctions via a single price coupling algorithm which simultaneously determines volumes and prices in all relevant zones, based on the marginal pricing principle. The implementation shall take into account the role of the power exchanges (PXs) and shall require the harmonisation of day-ahead bidding deadlines." [footnotes omitted]

[77] ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 4.1, page 10.

[78] ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 2.1, page 6.

[79] ACER (2011), *Framework Guidelines on Capacity Allocation and Congestion Management for Electricity*, 29 July 2011, section 5, page 11.

## A.4. Balancing by TSOs

234. The role of TSOs in balancing is set out in the *Framework Guidelines on Electricity Balancing* ("Balancing Guidelines") which ACER issued in September 2012.[80] ACER foresees TSOs collaborating to achieve the following objectives:

- "safeguarding operational security;
- fostering competition, non-discrimination and transparency in balancing markets;
- facilitating wider participation of demand response and renewable sources of energy;
- increasing overall social welfare and efficiency;
- promoting cross-border balancing exchanges."[81]

235. More specifically, the Balancing Guidelines require TSOs to collaborate on achieving an efficient joint despatch across all systems, using the principles of a (least-cost) merit order to minimise the cost of balancing.[82]

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80 ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012.

81 ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, section 2.1, page 12.

82 "TSOs are responsible for organising balancing markets and shall strive for their integration, keeping the system in balance in the most efficient manner and following the general objectives defined in Section 2.1 of these Framework Guidelines. To do so, they shall work with each other in close cooperation and coordinate their activities as much as necessary.…the Network Code on Electricity Balancing shall define that exchanges of balancing energy are to be based on a TSO-TSO model with common merit order list. In this model, TSOs share their balancing resources and optimise their activation in order to minimise the cost of balancing..." ACER (2012), *Framework Guidelines on Electricity Balancing*, FG-2012-E-009, 18 September 2012, sections 2.1 and 3.3.2, pages 12 and 17.

# Appendix B. Market Design Criteria

236. This appendix sets out the design criteria that any electricity market should meet, to ensure that it underpins efficient investment in generation capacity and demand-side response (in the long term) and efficient operation of generation and consumption of electricity (in the short term). Together, these aims combine into a requirement that electricity markets should encourage least cost production (i.e. productive efficiency) and set prices that reflect marginal costs (to promote allocative efficiency).

## B.1. Market Infrastructure

237. Any "electricity market" consists in practice of a number of interlocking arrangements for trading electricity (markets) and for issuing generators and demand-side resources (DSR) with command-and-control instructions (scheduling and despatch). These arrangements must fit together in a way that meets certain operational criteria, specifically:

1. **Market design must permit secure operation of the system by the TSO, so that generation always matches demand ("security of supply"); and**
2. **Market pricing rules (in conjunction with any capacity remuneration mechanism) must allow total generation capacity that is efficiently selected (investment) and operated (despatch) to recover its costs.**

238. Some command-and-control arrangements will inevitably be required (because certain events happen too fast, or have too short a duration, to be managed through market transactions). However,

3. **"Gate closure", when central despatch and administrative pricing take over from decentralised contracts and trading, should occur at the latest possible stage before delivery.**

239. Centralised arrangements will apply to some or all of the following (with reasons in brackets):

- Ex post imbalance charges (essential in all regimes)
- Real time spot market (integrated with central despatch)
- Day ahead markets (possibly integrated with central scheduling, but also required by EU harmonisation requirements on market coupling)
- Forward markets (if central intervention is required to promote the market and justified by net benefits over decentralised trading)

240. Some provision for centralised, administrative and ex post pricing of imbalances is a feature of every functioning electricity market. It is by definition impossible to set up contracts for individual imbalances in advance. Instead, imbalance pricing arrangements provide a contractual (or, at least, legal) basis for pricing imbalances when they occur. Imbalances provide an alternative source of, or outlet for, generation to all other electricity markets – one MWh more/less purchased by contract converts (independently of any adjustment to output or consumption) into one MWh less/more on the trader's imbalance account Hence, the value of a contract is the avoided cost of an imbalance. This cost also defines the value of

generating an extra MWh and the cost of consuming an extra MWh (independently of any other adjustment to contracts) The price put on these imbalances therefore supports the prices in all these other electricity markets and provides the final incentive to generate or consume electricity in real time. It follows that electricity market design processes must give detailed attention (using the criteria set out here) to the prices for ex post imbalances, as well as the pricing algorithms used in other electricity markets.

241. Two further principles arise as corollaries to the desire to attract efficient investment:

4. **The market design should allow traders to maintain a contract portfolio that at all times hedges the price of their expected output, and to change their contract position if their expected output changes.**
5. **The electricity market infrastructure, the format of offer/bid prices and market pricing rules should allow non-discriminatory access by all generation and DSR technologies.**

242. Electricity market prices - for real-time, intra-day, day-ahead and other trades and for imbalances – vary widely and somewhat unpredictably. In contrast, a large proportion of generators' costs are fixed, and for many the variable component depends on international fuel prices. This combination of revenues and costs imparts a high degree of risk to long-lived investment in generation. Investors need to manage.this risk, e.g. to limit the maximum loss that a generator can incur due to adverse movements in prices and costs. Efficient market designs should not prevent traders using contract to manage these risks. The inability to use contracts may drive investors towards particular industry structures (e.g. vertical integration) or technologies (e.g. thermal plant whose variable costs are correlated with electricity market prices). Such biases prevent efficient choices.

243. Ideally, electricity markets should permit all *possible* technologies to enter the market and to be selected purely on the basis of their costs and risks. In practice, electricity market design can usually only ensure that all *known* technologies can participate efficiently – including likely future technologies and demand-side participants.

244. To achieve this aim, offer/bid price formats must accommodate multiple cost structures on a non-discriminatory basis (avoiding technology-specific rules, where possible). In addition, the timing of data submission and gate closure should be consistent with the ability of individual generators to match their output to their sales. This criterion requires careful consideration of: (1) the dynamic characteristics and "non-convex" (e.g. start-up) costs of thermal plant; and (2) the (un)predictability of output from wind or solar plant. In addition, the market infrastructure must provide a basis for efficient use of (3) interconnector capacity, which takes account of the varying costs of supply (or demand) from other markets.

## B.2. Market Organisation

245. The organisation of decentralised contract markets or voluntary exchanges can be left to the participants. Centralised market arrangements (including ex post imbalance pricing) should meet the following design criteria.

246. Centralised markets should adopt the same principles as efficient, decentralised markets both in matching supply with demand and in setting the price. In particular, efficient markets

select offers to supply in increasing order of cost and bids to buy in decreasing order of value, so as to maximise the net welfare of the market clearing outcome. Efficient markets then set prices equal to the marginal cost of supply (or, in some conditions, the marginal value of demand[83]). These principles can be expressed as follows:

6. **The market or despatch algorithm should select offers (and bids) in an efficient least-cost "merit order".**
7. **Prices should reflect marginal costs in the geographic market concerned, i.e.: (1) the "system marginal cost" for markets covering the whole system; (2) the "local marginal cost" of individual generators operating within a local market (e.g. for generators that are "constrained on" or "constrained off" and running out of merit).**
8. **Prices should reflect marginal costs over the timescale of decisions associated with trading in the market concerned.**

247. Principle 8 relates to the calculation of marginal costs (and hence prices) when cost functions are "non-convex", meaning that generators have to incur some costs (start-up, hourly no-load, etc) in order to generate any output.[84] These costs are marginal to total output over some period (a few hours, a day, or longer) even though they cannot be attributed directly to any individual unit of output. Because they cannot be assigned directly as a marginal cost of any individual unit of output, they must be allocated by a rule to several different units of output.

248. The design of the rules used to allocate non-convex costs complicates the operation of any market, but is essential to meet the following criterion, which promotes efficient despatch and allows generators to manage their risks:

9. **Pricing rules should offer market participants the assurance that:**
   a. **generators will receive a price above their marginal costs when they generate;**
   b. **generators will generate whenever the price is above their marginal costs;**
   c. **generators will not generate if the price is below their marginal costs; and**
   d. **equivalent rules apply to the acceptance of offers submitted to markets;**
   e. **equivalent (but obverse) rules apply to the supply of, and bids from, despatchable DSR.**

[83] This pricing rule applies when supply hits a constraint, such as a step change in production costs or an absolute limit on output. In these cases, the system marginal cost is defined by the cost of depriving consumers of supply, rather than the cost of increasing supply. In most cases, however, efficiently matching supply with demand sets the marginal cost of supply equal to the marginal value of demand.

[84] When costs are "convex", each successive unit of output costs more than previous ones. In these conditions, setting the market price equal to marginal cost – i.e. the cost of producing the last unit of output – guarantees that the price will cover the cost of producing all units of output. However, if costs are "non-convex", this simple rule may not result in a price that covers all the costs of producing output to serve this market. Such an outcome does not encourage efficient generation and pricing rules in many electricity markets provide for the inclusion of the "non-convex" costs within a measure of each generator's offer price, before identifying marginal costs.

249. This is a rather more general statement of the principle set out on page 88 of the Draft Decision, which refers to a book by Steven Stoft. The extract quoted there covers criterion 9a, but not 9b or 9c.

250. It is a corollary of this principle that market participants should be able to understand how prices are set, and that there should be no ad hoc or subjective intervention in price-setting, but this principle is worth stating separately:

**10. Price-setting rules should be transparent (i.e. they should use objective data in pre-defined formulae).**

251. Note that these criteria represent a restricted set which takes a number of design parameters for granted, such as the duration of the settlement periods to which separate prices apply.

## B.3. Market Power

252. The principles set out above apply to any market, but implementing them may be difficult if the designers cannot rely on the forces of competition to impose certain outcomes. If certain players possess a high degree of market power that is expected to persist for a long time,[85] achieving the principles above may require the adoption of measures to mitigate market power. These measures should also abide by certain principles, to ensure that they do not hinder the achievement of the others (or at least to minimise their negative impact), and to ensure that they do not discourage market participants from behaving in a competitive fashion.

**11. Measures to mitigate market power should be transparent (i.e. use objective data in pre-defined procedure).**

253. For example, the current Bidding Code Of Practice (BCOP) requires market participants to submit offer prices that, in summary, include cost items incurred over a daily timescale, and valued at their opportunity costs. Applying these rules is relatively straightforward in the current SEM, because the format of offer prices matches the structure of production costs at most generators. Sometimes, disputes have arisen over the relevant timescale for including cost items and over the concept of opportunity cost, but these disputes can be resolved in an objective fashion which provides guidance for future decisions by market participants. If the new I-SEM defined offer prices in simple €/MWh terms, the same procedure could not be applied objectively without additional rules, because individual generators would have to make subjective commercial decisions about the allocation of their "non-convex" costs (see above).

254. Finally, it seems desirable to limit any market power to the market where it is found, and to prevent its extension into other markets through vertical integration by ownership, contract or other means. For example, given that there is a dominant producer in the Irish generation

[85] Individual producers (or buyers) may possess market power at particular times, but the motivation for intervention is a fear that such market power will persist and will not be eroded by the decisions of competitors. The ability to earn high profits by exercising market power is in practice the normal means of providing an incentive for efficient entry by new competitors. Prohibiting all such profit opportunities would remove the incentive for innovation and eliminate any effective role for competition.

sector, it would seem desirable to prevent that producer from extending its market power into forward contract markets or into the retail electricity market.

**12. The existence of market power in one market should not preclude competitive entry or supply of services in a related market.**

255. In the specific case of the Irish electricity market, there may be a need not only for measures to mitigate market power in generation, but also for measures to protect or promote competition in forward contract markets and retail electricity markets.

# Appendix C. Discussion of Interconnector Capacity Rights

256. The DDP contains a discussion of physical and financial transmission rights (PTRs and FTRs) on the interconnectors in section 6.4, but it contains a number of errors. This appendix sets out some of the key points made in the DDP, along with corrections.

## C.1. PTRs, FTRs and Nominations into the I-SEM

257. "Though FTR Options are equivalent to PTRs with UIOSI, FTR Options have the key advantages of not requiring nominations of physical forward contracts into the I-SEM or harmonised physical nomination rules with neighbouring zones in the region or at pan European level." (DDP, 6.4.11)

258. This statement misrepresents both the ease of implementing FTRs and the difficulty of implementing PTRs on the interconnectors. Making FTRs work requires a major effort to synchronise day-ahead markets, in order to permit an implicit auction. Synchronising day-ahead nominations of interconnector flows does not appear to present any greater problems. Gate Closure occurs at or after the day-ahead stage in both Ireland and Great Britain, and so does not represent a constraint on the time at which traders fix flows over the interconnectors.

## C.2. Relationship Between PTRs and the Day Ahead Market

259. "Given the size of the I-SEM market relative to interconnection capacity, issuing PTRs would risk 'locking out' 20% of the market (i.e., the entire capacity of the cross border lines relative to the size of the all island system) from the day ahead energy market clearing process." (DDP, 6.4.12).

260. This statement seems to be untrue, or at least not to be true under all the Options. Under Option 3, for instance, PTRs could require holders to finalise their use of interconnector capacity at the day-ahead stage, by offering a given output to the DAM. They would do so as the DAM is the "exclusive" route to file physical notifications.

## C.3. Netting Off (Offering Capacity in the Reverse Direction)

261. "FTR Obligations would allow for netting of interconnector capacity, thereby increasing competition between generators and suppliers in both markets" (DDP, 6.4.13)

262. This statement is misleading in two senses. First, netting is possible not only on the capacity covered by FTRs, but also on capacity covered by PTRs. In other words, suppose that an interconnector offers 1,000 MW of capacity in either direction, and that PTR holders schedule 1,000 MW from East to West. The TSO can immediately offer West to East capacity of 2,000 MW, just as the TSO would do through an implicit auction with FTRs.

263. Second, providing this flexibility facilitates efficient arbitrage between the two markets, but it is not clear how it increases competition. Netting is really just one form of UIOSI/UIOLI rule, and offers no additional advantages for competition. Netting does not increase the real net supply of electricity into either new market – each new supply created by netting is offset by a new demand and so leaves the balance of real supply and demand unaltered.

### C.3.1. Unnamed and possibly irrelevant sources of evidence

264. "A consultancy report to the European Commission from 2011 recommended that FTR Obligations be adopted throughout the Target Model mainly because of the competition promoting attributes described in the previous paragraph." (DDP, para 6.4.14)

265. The recommendation in a consultancy report is not really compelling or objective evidence in favour of any particular solution. The DDP should say who wrote the consultancy report and whether they represent an independent opinion or are merely one of the SEM Committee's advisors. (We cannot check these points, as the reference in footnote 17 does not work.)

266. Moreover, the DDP should recognise that the European Commission did not accept the recommendation, since the EU Target Model accepts the possibility of using both FTRs and PTRs. If there is any guidance towards using FTRs, the DDP would have to show that it was motivated by the desire to promote competition, since such effects appear to be a myth.

### C.3.2. Speculation and subjective interpretations

267. "FTRs [may] replace PTRs on an increasing number of interconnections across the EU in the coming years…" (DDP, 6.4.15)

268. "FTRs (Options and Obligations) are the preferred model for allocating transmission capacity and hedging congestion in many markets in the United States…FTRs are far from untested in market designs and are part of the FERC Standard Market Design." (DDP, 6.4.16))

269. The first of these arguments is just speculation about the future systems in Europe. The second is a subjective interpretation of the facts, since there is no evidence that FTRs are "preferred", or what that really means. The FERC Standard Market Design mentions FTRs, but was rejected by many market participants and operators, so that it does not have any real effect. It is certainly not the US equivalent of the EU Target Model.

### C.3.3. Failure to recognise drawbacks of FTRs

270. "The SEM Committee is not aware of any evidence that there are any material drawbacks to implementing FTRs." (DDP, 6.4.16)

271. The SEM Committee has overlooked the fact that use of FTRs effectively prevents capacity in neighbouring countries from serving the Irish capacity market. Whenever cross-border trade in capacity has been allowed, the only way to make it effective has been to limit trade to generators who possess PTRs on the interconnector. These PTRs contain physical scheduling rights required to ensure that generators in neighbouring markets can and will provide energy when needed. The SEM Committee has not considered this possibility and so is forced to rule out cross-border trade in capacity (in favour of a compromise position on interconnector capacity).

### C.3.4. Confusion of efficient trading and efficient usage

272. "Furthermore, in order for the all island market to integrate further into the European Internal Market it is important that the existing interconnectors are used optimally.…The SEM Committee believes that FTRs best achieve these objectives." (DDP, 6.4.17)

273. This sentence provides another indication of the SEM Committee’s confusion over the difference between efficient arbitrage, and efficient usage. Even if FTRs promote more liquid day-ahead trading (which is doubtful), they will only foster efficient day-ahead arbitrage. Efficient use of interconnectors depends on the scope for real time adjustment to cross-border flows, through intra-day markets and balancing markets (inter-TSO cooperation).

### C.3.5. One-Sided Use of Equivalence

274. Paragraph 6.4.18 of the DDP sets out the ways in which FTRs are equivalent to Physical Transmission Rights with a “use it or sell it” condition (“PTRs+UIOSI”). The SEM Committee uses this equivalence to support the use of FTRs. However, it might just as well support the use of PTRs with suitable (UIOLI/UIOSI) conditions that make unused capacity available to others in real time. These arguments seem therefore to add nothing to the case in favour of FTRs.

# Appendix D. Review of the Qualitative Assessment

275. Section 5.5 of the IIA sets out a "qualitative assessment" of the four Options. It suffers from the same problems of subjectivity and potential bias outlined above. The following comments therefore identify specific problems in relation to the individual assessment criteria used in that section.

## D.1. Internal Electricity Market

276. Section 5.6 of the IIA opens with the "five pillars" of the EU Target Model, but then fails to apply them rigorously or consistently to all the options. For example, three of the "pillars" are "day-ahead market coupling", "intra-day continuous trading" and "cross-border balancing". These pillars represent specific institutions – but the appraisal does not consider whether each Option contains these institutions, but rather how well these institutions will perform under each option, by reference to rather vague criteria. For instance, in the section on Option 1, paragraph 5.6.4 considers the liquidity of day-ahead and intra-day markets and their impact on the "effectiveness" of day-ahead and intra-day market coupling. However,

- there is no definition of "effectiveness" for *day-ahead market coupling*;
- there is no explanation of the relevance of *intra-day market coupling* (which is *not* one of the "five pillars"); and
- there is no consideration of the nature, existence, effect, "effectiveness" or efficiency of *cross-border balancing* (which is one of the "five pillars").

277. The remainder of this section (paragraphs 5.6.1 to 5.6.21) is full of such selective and subjective assessments, using undefined terms. The first sentence of the final paragraph states that all the options are compliant with the requirements of the EU target model. In principle, that sentence ought to comprise the full conclusion on this section. However, the next sentence says that Option 3 is superior to the other Options, because of its impact on liquidity, without saying why this criterion is relevant for – in fact, dominates – the assessment of compliance with the EU Target Model. In fact, it is merely further evidence of a selective, biased and subjective appraisal process.

## D.2. Security of Supply

278. Once again, this section (paragraphs 5.6.22 to 5.6.40) contains one short statement that answers the question. Paragraph 5.6.24 reports the statement by EirGrid that it can maintain system security under any of the four Options. That is a definitive response. This section of the IIA contains however a protracted discussion of the arrangements for day-ahead trading and nominations, without explaining why that is relevant to the criterion of security of supply. Paragraph 5.6.34 praises Option 3 for the liquidity of the DAM, as advantageous "in terms of longer term security of supply" (because it provides reference prices for forward trading). However, paragraph 5.5.5 states that Option 3 requires further development and specification in the areas of "incentives for market participants to participant in the DAM" and "additional measures to support forward market liquidity as spot market liquidity on its own will not guarantee the development of forward market liquidity." Either the authors of the IIA did not notice the contradictions between these paragraphs, or they have simply adopted a prejudicial

view of Option 3, ignoring any potential obstacles to favourable outcomes under Option 3 whilst highlighting such obstacles under other Options.

## D.3. Competition

279. The over-riding impression given by this section, paragraphs 5.6.41 to 5.6.55, is that it is based on very little understanding of competition policy and the associated economics. Competition policy is about making sure that market institutions support competition among producers in a way that benefits consumers. Instead, paragraphs 5.6.43 (Option 1), 5.6.46 (Option 2), 5.6.49 (Option 3) and 5.6.52 (Option 4) all focus on liquidity and “routes to market” as a means of favouring certain market participants.

280. Paragraph 5.6.43 concludes that Option 1 would require “liquidity promoting measures”. Paragraph 5.6.49 says that liquid centralised markets are a key feature of Option 3, providing “competitive but equal routes to market for all players”, but this appraisal overlooks the need under Option 3 for measures to promote (forward) market liquidity mentioned in paragraph 5.5.5.

## D.4. Environmental

281. The difficulty of applying this criterion is set out clearly in the first (unnumbered) paragraph of this section. It states that “a market cannot be designed specifically around renewable generation”, but then concedes that “the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.” The latter statement just means in practice that any market that is not “designed about renewable generation” will be rejected. However, in practice, little of this section is related to renewable generation or more general environmental goals. Much of the text concerns matters such as liquidity and reference prices, which have little to do with the environment per se. This discussion assumes implicitly, without saying so, that the market must be designed to support the current instruments of government environmental policy.

282. Paragraphs 5.6.60, 5.6.63, 5.6.65 and 5.6.70 assess whether flexible resources will receive proper recompense under each Option. This question arises from the prediction that rising volumes of renewable generation will require a concomitant increase in the level of flexibility offered by thermal generation. However, this question overlaps with the previous discussion of security of supply (where EirGrid said that all Options were compliant) and the later discussion of efficiency (which deserves greater emphasis than it receives).

## D.5. Equity

283. This section, from paragraph 5.6.75 to 5.6.93, suggests that, having adopted equity as a criterion, the authors found it hard to define equity as a separate standard. The “equality of access” described in paragraph 5.6.75 is indistinguishable from “competition”. Paragraph 5.6.76 proposes to review the “delivery of an allocative[ly] efficient outcome where prices reflect marginal costs”, which overlaps directly with “efficiency”. As a result, perhaps, the authors are drawn into making a number of subjective and unsupported statements on unrelated matters.

284. For instance, paragraph 5.6.78 says that Option 1 "places the greatest reliance on competitive market structures underlying the market". There is no analysis to back up this statement, nor any real explanation of what is meant by "places the greatest reliance on…." The same paragraph also states that "In the absence of such a competitive structure, it places reliance on adaptations to achieve competitive outcomes", but that statement is true of all the Options – indeed, of all markets everywhere. It does not therefore help to evaluate Option 1 relative to the others.

285. Paragraph 5.6.79 says that a portfolio player "may" choose to use its own sources of generation, even if cheaper generation is available from others, without saying why such behaviour would be economically rational under Option 1 - and without explaining why it would not occur under other Options. Paragraph 5.6.80 identifies transactions costs as a problem under Option 1, but does not say whether centralised markets operating under the other Options would (a) reduce transactions costs or (b) merely hide them and impose them on others.

286. Much of this section consists of vague or speculative statements about each of the Options, on a shifting range of topics that defies any attempt to make a comparison between the Options.

## D.6. Stability

287. Paragraphs 5.7.2 to 5.7.10 profess to consider the stability of each Option. The brief definition at the start of the section refers to the desire for arrangements to be "stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations." In practice, any market will be stable throughout its own lifetime; what matters is the long term stability of markets over the lifetime of investment projects. To apply such a criterion, the IIA would have had to define what kind of long run stability was important to investors, by reference to the remuneration offered for long term investment.

288. Instead, the IIA discusses the extent of any differences between the institutions in each Option and (1) the current SEM and (2) electricity market institutions in the rest of Europe. That approach is bound to favour an Option whose institutional design sits between the current SEM and other markets. However, electricity market designs change all the time and the current round of reforms intended to implement the EU Target Model cannot be regarded as the final round. Any assessment of the long run stability of institutions (as opposed to the returns to investors that they offer over the long run) would have to assess the internal pressure for change, by identifying potential inefficiencies and inconsistencies, rather than merely by noting the differences from other (temporary) institutions.

## D.7. Adaptive

289. This criterion seems to be motivated by the desire to make changing the rules easy for bureaucrats, which conflicts with the desire for stability expressed under the previous criterion. In any case, the appraisal seems highly selective and to apply different definitions of the criteria to different Options. For instance, paragraph 5.7.11 accuses Option 1 of being difficult to adapt to local circumstances, "if there is a liquid DAM and IDM…on the organised, centralised European markets"; this condition conflicts with all the rest of the assessment, which ascribes to Option 1 specifically a *lack* of liquid markets. Paragraph

5.7.14 says that Option 2 will be "vulnerable to external change" because it differs from other markets, but does not explain why it would need to change, or why changes would be expensive if they involved adopting other systems that already existed. Paragraph 5.7.16 seems to suggest that Option 3 will be highly "vulnerable to external change" like Option 2, because it is tied to European systems, but then concludes perversely with a positive finding that the governance arrangements should accommodate any changes required by local conditions. This contrasts with the discussion of Option 4 in paragraph 5.5.17, which identifies a difficulty in having to amend the model to reflect changing European requirements, rather than a benefit in having a model that already reflects local conditions.

290. Depending on the Option being considered, therefore, this section adopts different and conflicting attitudes to future changes driven by European and local requirements.

## D.8. Efficiency

291. The discussion of efficiency in this section is only cursory and broadly repeats the consideration of markets, scheduling and despatch set out in other sections of this report. Once again, paragraphs included in the appraisal of an individual Option make statements of a positive or negative character which affect the reader's view of that Option, whereas in practice they apply equally to all the Options. For instance, paragraphs 5.7.23, 5.7.26 and 5.7.30 point out for Options 1, 2 and 3 that the impact of non-energy factors (i.e. reserve – and other ancillary services) on physical nominations will depend on the arrangements for procuring them. It is not clear why this statement is missing for Option 4. In reality, it applies to any electricity market, and so plays no role in selecting one design from many.

292. The summary in paragraphs 5.7.33-35 does not in practice evaluate all four options by the criterion of efficiency. Instead, it asserts once more that Option 3 is efficient, albeit only by reference to day-ahead integration of interconnectors. (Once again, it overlooks any other aspects of efficiency, such as the effect of intra-day and real-time adjustments.) Therefore, this section does not add anything to the (rather scant) discussion of efficiency in earlier sections of the IIA and in the DDP.

## D.9. Practicality/Cost

293. As in other sections of the IIA, paragraphs 5.7.36 to 5.7. 52 highlight the difficulties involved in implementing Options 1, 2 and 4, whilst allowing for further work in the detailed design stage to make Option 3 overcome criticisms from respondents. This part of the appraisal is therefore as selective and biased as any in the IIA.

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# Scheduling risk under the proposed I-SEM High Level Design

## An issues paper

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**Confidentiality and Limitation Statement**

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# 1. INTRODUCTION

The SEM Committee published the I-SEM High Level Design Proposed Decision on the 9th June 2014. The proposed design will consist of a financial forward hedging contract market referenced against a physical unconstrained day-ahead schedule produced by the EUPHEMIA algorithm as a part of the European market-coupled auction, together with bilateral within-day trading and a balancing market operated by the system operator. The SEM Committee proposes that the centralised Day-ahead Market (DAM), Intra-day Market (IDM) and Balancing Market will be the exclusive routes for physical contract nomination and physical scheduling of generation. It is proposed that participation in the DAM and IDM will be exclusive but not mandatory, whereas participation in the Balancing Market will be mandatory.

The proposed I-SEM High Level Design is formulated to ensure that the Irish electricity market is compliant with the EU Target Model by 2016. Whilst the proposed design will bring the market more in line with other European markets in some respects, for example allocating interconnector capacity implicitly through day-ahead market coupling and making participants more responsible for balancing their own positions, it would still be unique amongst other European markets which typically are centred around full self-dispatch and voluntary participation in multiple physical traded markets. Furthermore, the proposed design does not explicitly tackle one of the key issues in the current SEM, namely the lack of forward liquidity which is important for a well-functioning market. One of the contributing factors behind poor liquidity in the current SEM is the scheduling risk faced by generators, since they cannot with confidence assume that they will be appropriately scheduled under the central market arrangements against their forward commitments.

Liquid and transparent forward markets enable suppliers to hedge efficiently, thereby shielding consumers from volatile spot markets and enabling competitive tariff structures. Forward markets also provide open access to mitigate market power and concentration, and generate price signals to drive investment. Effective functioning of forward markets is therefore essential for competition and consumer choice.

In this paper, we explore the extent to which scheduling risk would remain under the proposed I-SEM design and the implications for forward market liquidity. We are not implying or proposing solutions to these potential issues within the contents of this paper.

## 2. PARTICIPATING IN THE I-SEM

The day-ahead market (DAM) forms a central part of the proposed I-SEM High Level Design, providing:

- The basis for the day-ahead dispatch schedule
- The mechanism for allocating capacity on interconnectors with the GB market
- The reference price for settling forward financial contracts, and
- The (likely) reference price for settling reliability options under the proposed Capacity Remuneration Mechanism (CRM)

Since the DAM will be exclusive, dispatchable generators will be strongly incentivised to offer their output through this market (even if it were not mandatory)[1]. Each day the generator will need to formulate its offers using the available exchange offer formats, and consider how best to reflect its underlying costs in its pricing approach. In doing this, it will need to consider external factors such as the level of demand and wind output, and the potential strategies of competitors. It will also need to take a view of the likely initial status of the plant at the start for the trading day, for example whether the plant will be already operating or needs to be started which would require start costs to be recovered in its offer price.

The schedules produced by the EUPHEMIA algorithm at the day-ahead stage are unlikely to be fully feasible, and will need to be adjusted to take into account actual ramping characteristics of individual plant, as well as for system operational reasons, such as managing transmission constraints.

At this stage, it is not decided how much responsibility individual generators will have post the DAM for creating feasible schedules versus the system operator. If it is to be generators, a liquid within-day market will be essential, since the proposed marginal imbalance price arrangements would represent a significant risk for generators (particularly independent generators) constrained to the relatively blocky nature of offers in the DAM.

Participation in the balancing market is mandatory for generators. In pricing their balancing bids and offers, generators will need to consider the impacts on their assumed starting positions used for preparing offers into the next day's DAM. For example, had the generator assumed that it would begin the day generating, any bid to switch off in the balancing market would need to factor in the costs of re-starting the plant (which were not included in the DAM offer price).

Overall, the proposed I-SEM HLD places far more risk on generators associated with managing their own dispatch and internalising their own costs when compared to the current SEM based around a pool and central dispatch. To manage this risk effectively will require access to the tools typically available in bilateral markets based on self-dispatch, namely day-ahead and within-day liquidity and real-time information on system conditions. An imbalance price that accurately reflects the costs of achieving an energy balance across the system (i.e. a price that is not 'polluted' by balancing actions required to maintain the physical integrity of the network such as constraint management), and established through effective competition between providers of balancing energy, will also be essential.

[1] The alternative of attempting to transact all its output in the within-day market would expose the generator to considerable liquidity risk.

## 3. WHAT IS SCHEDULING RISK?

### 3.1. Definitions

Scheduling risk occurs in centralised markets, such as the current SEM and the proposed I-SEM, since a generator cannot be certain that its plant will be appropriately scheduled under the market or exchange algorithm. This makes the task of managing earnings risk through hedging forward its output and fuel requirements more difficult than is the case in a self-scheduled market.

A baseload generator, one whose short run costs are predictably below the market price, is unlikely to have significant exposure to scheduling risk. There are no start costs to be recovered, and the baseload generator can hedge its output and its fuel (and carbon) costs in forward markets (to the extent there is sufficient liquidity) and lock in a margin.

Scheduling risk is most acute for mid-merit plant, those generators whose output fluctuates according to system conditions and which may need to be frequently switched off and restarted. High efficiency CCGTs already operate as mid-merit units in the SEM and this trend is likely to continue with even more efficient currently baseload generation moving to mid-merit operation in the future with increasing levels of renewable generation.

A mid-merit generator cannot be certain whether it will be "in-merit". In a bilateral market with self-dispatch, the mid-merit generator is able to sell electricity forward and hedge its fuel cost for periods with positive spreads (taking into account potential start costs). Having the option to self-dispatch at the time of delivery then guarantees it can lock in the margin on its forward sale. If at the time of delivery the day-ahead price for electricity is above its short run costs (taking into account its start costs if it is not already running) it will choose to generate. However, if the day-ahead price is below its short run costs, it will re-optimise its position, choosing not to generate and instead purchasing its requirements from the day-ahead (or other prompt) market. This allows the generator to then stockpile its fuel (in the case of coal) or sell it (in the case of gas) to achieve additional margin. Under this dynamic, a generator can only improve on the margin it has locked in through its forward hedging strategy.

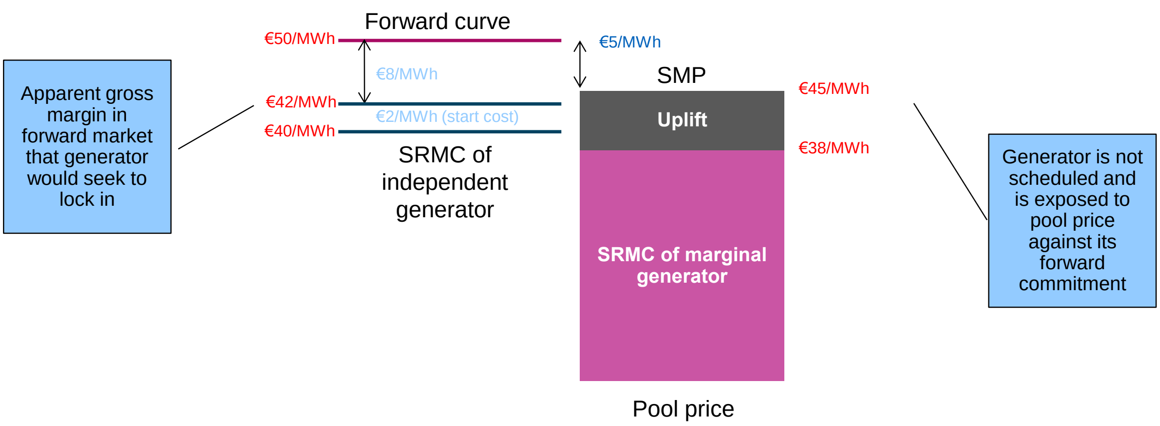
Under a centralised market, the hedging task for a mid-merit plant becomes more complex since it will be dispatched based on the outcome of the market algorithm. At the day-ahead stage there will be considerable uncertainty regarding market conditions, particularly with respect to wind output, and the potential bidding strategies of competitors. In the absence of a Bidding Code of Practice it will be significantly more difficult than under the current SEM to anticipate the offers of competitors, which will increase scheduling risk. A key challenge for generators will be how to internalise start costs and no load costs into offers when there is a high degree of uncertainty regarding the fixed output that these costs can be spread over without increasing risk of exclusion from the DAM schedule. Generators also face the additional problem of how to construct commercial offers that ensure the DAM schedule they receive respects the dynamic technical constraints of their unit(s). It is therefore possible under the proposed design that a generator, bidding at cost, will not be scheduled, even if the DAM price is higher. In this scenario a generator that had hedged forward would be exposed to the market price, at a loss relative to its SRMC. This is scheduling risk.

In the current SEM these important issues are addressed (albeit imperfectly as discussed in Section 3.2 below) through complex commercial and technical offer formats, and the Uplift algorithm, but under I-SEM the under recovery of start-up and no load costs and the receipt of a technically infeasible schedule are likely to represent an increased material risk for generators. The reasons for this are discussed in Section 4 below.

## 3.2. Scheduling Risk in the current SEM

Under the mandatory pool structure of the current SEM, it is difficult for a mid-merit generator to execute a forward hedging strategy because it cannot determine its own schedule. This creates an anomaly whereby the generator can be 'in the money' in the forward market but is unable to capture the implied margin because it is not guaranteed to be scheduled appropriately through the mandatory pool. This problem is illustrated in Figure 3.1 below.

**Figure 3-1 Risks associated with forward hedging under the SEM**




In this example, the forward curve (€50/MWh) is trading above the generation costs (including the plant's start cost – spread across its anticipated running hours) of the independent mid-merit generator (€42/MWh). It therefore sells electricity forward and simultaneously hedges its fuel costs, thus in theory locking in a €8/MWh gross margin. At the day-ahead stage the generator submits an offer to the SEM based on its SRMC (€40/MWh). In this illustrative example, the generator's offer price is slightly above the SRMC of the marginal unit on the system (€38/MWh), causing the generator not to be scheduled in the pool. The generator therefore sells back its fuel hedges and in so doing generates a revenue equivalent to its SRMC. This payment offsets the costs of buying power from the pool (€45/MWh) to meet its forward commitments but because the pool has priced above the SRMC of the generator it results in the generator retaining a residual exposure to the pool. This residual exposure constitutes scheduling risk and means the generator only achieves a gross margin of €5/MWh, lower than the €8/MWh expected on its forward sale. This risk may have contributed to the substantial premium on forward sales evident in the current SEM.

In a bilateral market this dynamic is less likely to occur. Generators still face a challenge in optimising their traded position, as this is done primarily with relatively simple traded products, albeit through multiple channels, but they do have the ability to self-schedule to meet physical forward commitments if they are unable to purchase power below its own costs in the day-ahead market, guaranteeing the margin on forward sales.

## 3.3. Potential scheduling risk issues under the proposed I-SEM HLD

As the example above illustrates, a key source of scheduling risk under the current SEM design is the separation of no load and start costs from SRMCs in the pricing algorithm. This can create a situation where a plant is not dispatched even when prices are apparently above its costs.

Under the proposed I-SEM High Level Design, the generator's no load and start costs are internalised by the generator and hence this specific example would not happen.

However, scheduling risk is unlikely to be eliminated under the new market design since dispatch still relies on the outcomes from a central algorithm (in this case EUPHEMIA) which market participants may not be able to anticipate reliably, particularly in the absence of a Bidding Code of Practice. EUPHEMIA supports complex and sophisticated offer formats to help participants manage their technical and commercial constraints within the day-ahead scheduling process. However, with the exception of the possible partial acceptance on profile offers, complex or sophisticated orders can normally only be executed fully or rejected fully, and this constraint can lead to EUPHEMIA rejecting some complex orders even if they are priced below the outturn market prices. Rejected orders that are apparently in-the-money at outturn prices are termed 'paradoxically rejected orders' in the EUPEHMIA literature.

In the absence of short run cost bidding principles, the generator may, however, have the option of offering at zero price into the centralised day-ahead market, although it is not clear from the Draft Decision Paper whether zero bidding would be allowed. Zero bidding would guarantee dispatch (unless the marginal unit was also bidding zero[2]) and reduce scheduling risk. The downside for the generator though is that it may have been able to fulfil its forward commitment at lower cost (if the day-ahead market outturned below its own costs). Also zero bidding puts downward pressure on day-ahead prices, particularly in a small market such as the SEM, which may undermine the value of forward contracts. Whilst there could be a rationale for a single unit to bid below cost (if others were not doing it), the price dynamics associated with multiple parties doing so are likely to be unfavourable to generators, and hence we would not expect this to be a sustainable strategy in the longer run.

Exposure to scheduling risk under the I-SEM is compounded by the proposed design of the Capacity Remuneration Mechanism which will be based on financial Reliability Options that are likely to be settled against the DAM price. It is possible under the design that a generator will be exposed to payments under Reliability Options but not been scheduled.

In the next section we provide some worked up case studies to illustrate the options for generators to reflect their cost structures using EUPHEMIA offer structures and the limitations of this which contribute to scheduling risk.

[2] This situation is possible, particularly in periods of high wind output.

# 4. I-SEM DAY-AHEAD SCHEDULING AND EUPHEMIA

## 4.1. EUPHEMIA offer types

The pan-European day-ahead market clearing algorithm, EUPHEMIA, can handle a multitude of order formats, ranging from simple hourly and block products through to more complex block formats (e.g. linked, exclusive) and sophisticated conditions (e.g. Minimum Income Conditions). A brief description of each order type is as follows:

- ***Simple Hourly Orders*** consisting of a price and quantity pair for a given hour
- Block Orders applying to multiple hours:
    - ***Simple Block orders*** consisting of a price with a fixed quantity over a set time
    - ***Profiled Block Orders*** consisting of a price with a varying quantity over a set time
    - ***Linked Block Orders*** introducing conditionality such that the acceptance of a 'child' or 'grandchild' block is dependent on the acceptance of a 'parent' block
    - ***Exclusive Groups*** consisting of Simple or Profiled Block Orders where the combined acceptance ratio cannot exceed 1
    - ***Flexible Block Orders*** consisting of a price and quantity pair for a set duration but with the block start time not specified
- ***Sophisticated Orders*** consisting of simple orders with constraints such as Minimum Income Conditions, Scheduled Stop or Load Gradients

While the EUPHEMIA algorithm has been designed to support the full suite of order formats listed above, in practice only subsets of these order formats have been implemented by individual power exchanges to date. EUPHEMIA has been deployed in the North-Western European (NWE) and Iberian regions since 4 February 2014. At present, only OMIE in the Iberian market is supporting sophisticated orders such as Minimum Income Conditions, which are based on the legacy order formats in that market. In the NWE region, the local power exchanges such as EPEX and N2EX have been rolling out 'smarter' block formats but we understand there are no immediate plans to introduce sophisticated orders. Relative to the proposed I-SEM design, the requirements for sophisticated offer formats are less in other European markets given their larger size and more diverse and flexible generation mixes, and the fact that EUPHEMIA is not used as an exclusive route for creating the market schedule.

The RAs' proposed HLD does not specify which EUPHEMIA order formats will initially be supported in the I-SEM DAM. However, as stated in the proposed decision paper, recent analysis has focused on the potential application of Block Orders, and "the requirements for sophisticated constraints such as the Minimum Income Condition may not be as important or as necessary as was previously thought". It is also worth noting that the offer formats available to market participants may not be decided unilaterally by the RAs but through the EUPHEMIA governance arrangements. For the purposes of this study, we assume that Simple Hourly Orders and complex Blocks Orders will be available to I-SEM participants, but not sophisticated orders.

## 4.2. Mapping of generator technical and commercial parameters to offer types

The current SEM trading arrangements feature a centralised scheduling and pricing algorithm which ensures that generator market schedules are both technically feasible and commercially viable. Generators explicitly submit technical parameters (such as ramp rates, minimum stable levels and minimum run times) for consideration by the algorithm. The Uplift component of the market price in the current SEM guarantees the recovery of variable operating costs, including start and no load costs, for generation plant selected to run in the market schedule.

However, in the I-SEM DAM, as in other more decentralised European power markets, participants will be expected to internalise decisions on how to factor generation technical and cost constraints within their scheduling and pricing. I-SEM participants may consider applying some of the more complex order formats supported by EUPHEMIA to proxy the technical and commercial parameters that are handled explicitly in the current SEM. Here we can consider the potential mapping of current SEM technical and commercial parameters to EUPHEMIA order formats.

**Table 4-1 Mapping of Commercial Offer Data**

| SEM Parameter | Explicit I-SEM proxy | EUPHEMIA Order Types | Observations |
|---|---|---|---|
| **Price Quantity Pairs** | ✓ | All formats, including Hourly Orders and Block Orders | • Prices as well as volumes may differ from hour to hour (current SEM limits generators to one set of prices per day) |
| **No Load Costs** | × | All formats, including Hourly Orders and Block Orders | • No load costs need to be internalised within Hourly or Block prices<br>• Higher prices for part-load operation can be represented using Linked Block Orders with the parent block incorporating no load costs |
| **Start Up Costs** | × | Block Orders, *or* Sophisticated Orders with Minimum Income Condition | • Start costs need to be internalised within Hourly or Block prices<br>• Using Linked Block Orders, start costs could be assigned to the parent block |

**Table 4-2 Mapping of Technical Offer Data**

| SEM Parameter | Explicit I-SEM proxy | EUPHEMIA Order Types | Observations |
|---|---|---|---|
| **Minimum Stable Generation** | ✓ | Block Orders | • 'All or nothing' acceptance criteria provides a proxy for minimum stable generation (MSG)<br>• The parent block of a Linked Block could be sized at MSG |
| **Minimum On Time** | ✓ | Block Orders | • Duration of a Block Order can represent minimum on times<br>• Except for a Flexible Block Order, the generator will need to pre-determine the hours of the day to which the block applies |
| **Minimum Off Time** | ✓ | Block Orders | • Duration of a Block Order can represent minimum off times<br>• |
| **Ramp Up , Ramp Down Rates** | ✓ | Profiled Block Orders , *or* Sophisticated Orders with Load Gradient | • Unlike the current SEM, generators will need to pre-determine the hours in which the ramp profile applies |

The generation and load resources in the SEM have differing commercial and technical characteristics. Technical constraints will be more significant for inflexible resources, while start costs may be more material for some generation types than others. SEM participants may consider applying different EUPHEMIA order formats, reflecting these characteristics. Here we summarise key features and limitations of the different order types, and their potential application (ignoring sophisticated orders, as discussed above).

## Table 4-3 Summary of order types

| Order Type | Features | Limitations | Potential Application |
|---|---|---|---|
| **Simple Hourly Orders** | Orders in each hour clear independently. | Risk of technically infeasible schedules for baseload and mid-merit generators, since no modelling of technical constraints. | • Flexible peaking generators<br>• Hydro generators<br>• Pumped storage<br>• Load |
| **Simple Block Orders** | Block duration can represent minimum on time constraints. 'All or nothing' acceptance criteria proxies MSG. | Participant needs to pre-determine the hours in which the block applies. | • Baseload generators<br>• Mid-merit generators<br>• Less flexible peaking generators<br>• Load |
| **Profiled Block Orders** | Profile shape can reflect technical ramp constraints and/or expectations of market value (e.g. lower volumes offpeak). | Participant needs to pre-determine the profile shape based on market fundamentals as well as internal constraints. | • Baseload generators<br>• Mid-merit generators<br>• Hydro generators |
| **Linked Block Orders** | No load and start costs may be allocated to parent block, allowing competitive pricing of incremental energy in child blocks. Allows reflection of higher costs for part-loading. Sale and purchase blocks may be linked. | Required for detail modelling of start and no load costs and technical constraints. Other power exchanges have limited the number of child blocks per parent, reducing potential flexibility. Order may be paradoxically rejected. | • Mid-merit generators<br>• Pumped storage |
| **Exclusive Groups** | Allows participant to submit alternative profiles for the market algorithm to optimise, without risk of over-commitment. | Algorithm delivers market optimal outcomes, which may not be the profit maximising outcome for participant. Cannot be combined with Linked Block Orders. Order may be paradoxically rejected. | • Mid-merit generators<br>• Hydro generators<br>• Energy limited plant<br>• Load response |
| **Flexible Block Orders** | Fixed duration and volume block with flexible start time to be optimised by market algorithm. | Other power exchanges have limited the number of Flexible Block Orders per portfolio. Order may be paradoxically rejected. | • Energy limited plant<br>• Flexible peaking generators<br>• Load response |

In the following section, we consider worked examples of how EUPHEMIA order formats could be applied by different SEM resources, such as baseload or mid-merit generation.

As we note in the table, many power exchanges have placed limitations on the number and size of block orders and other complex bidding formats that participants can submit in the DAM for consideration by EUPHEMIA. These limitations can help ensure the market clearing algorithm reaches a timely and feasible solution. For example, EPEX has restricted Linked Block Orders to only one child per parent, and one 'family' per portfolio and market area. In GB, N2EX allows up to three child (or grandchild) blocks per parent (or child) block. The proposed HLD for I-SEM does not specify what limitations, if any, are likely to be placed on the use of complex order formats by I-SEM participants.

## 4.3. Potential bidding approaches for SEM generators

In this section, we have developed a series of worked examples to consider how different SEM generation categories (baseload, mid-merit, peaking) could make use of the various EUPHEMIA order formats to manage their scheduling risks. The challenge of achieving a technically and commercially viable schedule is arguably most pressing for mid-merit generators. Peaking generators are typically more flexible, while baseload generators are less concerned about start cost recovery. Given the growing contribution of renewables in the SEM, the majority of CCGT and coal assets will operate as mid-merit going forward. Mid-merit generators are therefore the focus of our worked examples.

We have considered the cases of a typical CCGT and coal-fired unit operating in the SEM. The table below summarises the assumed technical and commercial parameters for these two units, which are based on representative mid-point values in the published 2013 Validated Model, together with observation of actual commercial offer data (for start costs).

**Table 4-4 Generic plant assumptions**

| Parameter | Unit | CCGT unit A | Coal unit B |
|---|---|---|---|
| **Maximum Capacity** | MW | 400 | 250 |
| **Minimum Stable Generation** | MW | 200 | 100 |
| **Minimum On Time** | Hours | 4 | 5 |
| **Minimum Off Time** | Hours | 4 | 3 |
| **Start Cost** | € | 95,000 | 30,000 |

Given these assumptions on the generator’s cost structure and technical constraints, we then consider how EUPHEMIA orders could be formulated.

For the purpose of this study, we have not attempted to simulate the day-ahead market clearing and price formation process in the I-SEM and interconnected markets. For illustrative purposes, we assume that the CCGT and coal units are operated by independent generators and essentially operate as price takers in the DAM. We used historical spot commodity prices (gas, coal, carbon) and electricity price profiles (SEM, GB day-ahead, GB within-day) to illustrate potential scenarios for characteristic days. We also note that the success of a particular offer strategy (in producing a cost-optimal generation schedule for an asset) will also be dependent on the strategies deployed by other generators, which will of course not be known in advance. As we are not simulating the algorithm, this is not something we are aiming to demonstrate directly with these examples, but to which we return in considering the implications in Section 5. Furthermore, the simplified methodology for our illustrative examples assumes that block orders will always be accepted if they are in-the-money, whereas in practice block orders can be paradoxically rejected in the EUPHEMIA market clearing algorithm.

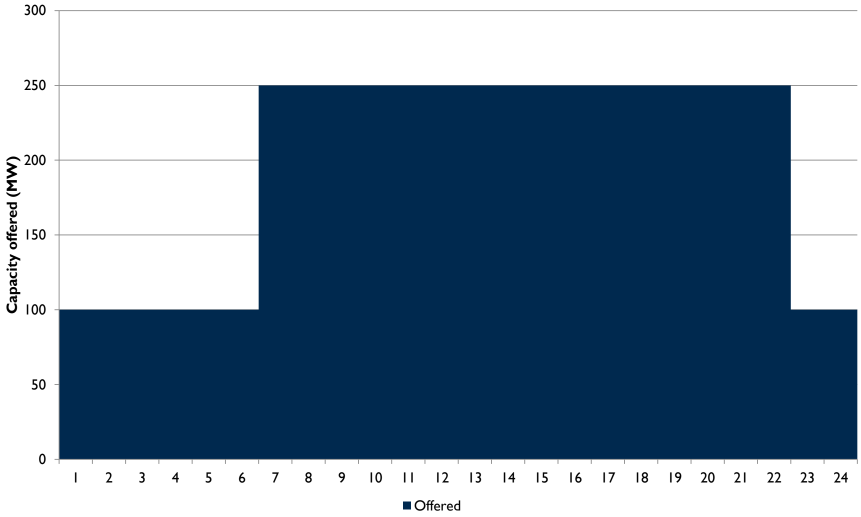
***Baseload***

The economics of baseload generators are such that they expect to be in-the-money in most periods. Start cost recovery is not generally a consideration given the continuous running profile. A Simple or Profiled Block Order format may be appropriate to represent technical constraints (such as minimum on time) and to ensure the plant is scheduled for the whole day in the DAM.

Case 1: Profiled Block Order

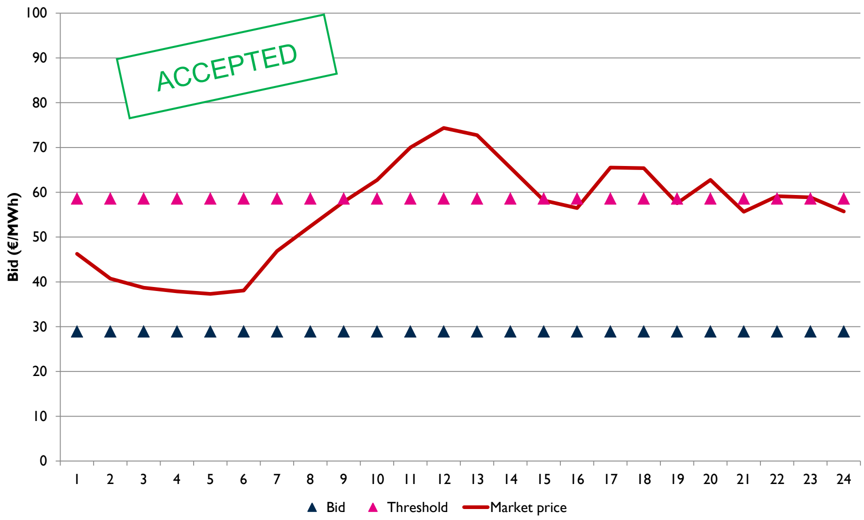
In this example, Coal Unit B expects to be near-the-money during the summer overnight periods and submits a Profiled Block Order to EUPHEMIA, as follows:

**Figure 4-1 Case 1 submitted Block Order for Coal B**




Coal Unit B is scheduled to be running at the end of the previous day, and so start costs do not need to be factored into its day-ahead bids. The unit's block bid price (reflecting its incremental and no load costs) is below the threshold of the volume-weighted average market clearing price, and the order is accepted.

**Figure 4-2 Case 1 Block Order pricing for Coal B**




The market price profile in this example implies that Coal Unit B could have sold incremental output overnight. Incremental power could be traded subsequently in the Intra-Day or

Balancing Markets. Alternatively, a Linked Block Order could be submitted to the DAM with child blocks representing incremental output above the base profile of the parent block.

EUPHEMIA does support partial acceptance of Profiled Block Orders, but this feature has not yet been implemented by all participating power exchanges.

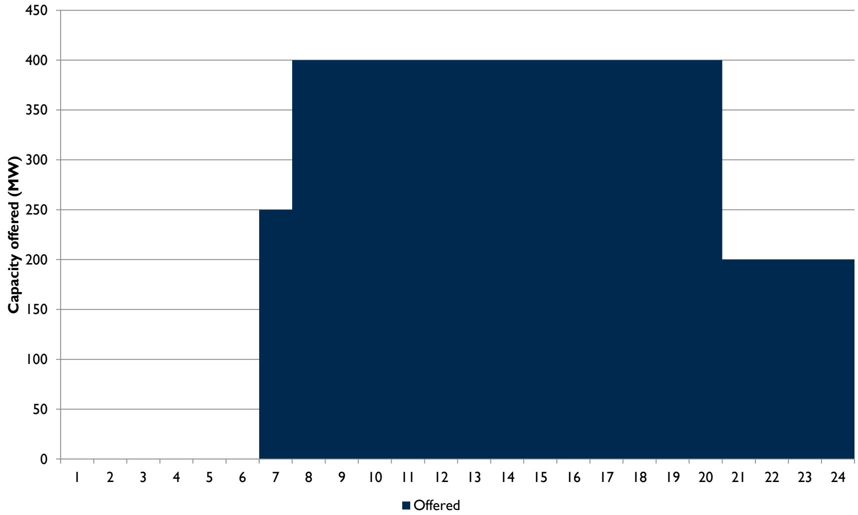
***Mid-merit***

Mid-merit plant may be in or out of the money depending on system and market conditions. As a result, these plant may need to be switched off and restarted on a regular basis. We consider three EUPHEMIA order formats that mid-merit could potentially utilise to manage scheduling risks in the I-SEM DAM – Profiled Block Orders, Linked Block Orders and Exclusive Groups.

*Profiled Block Order*
Case 2: Profiled Block Order

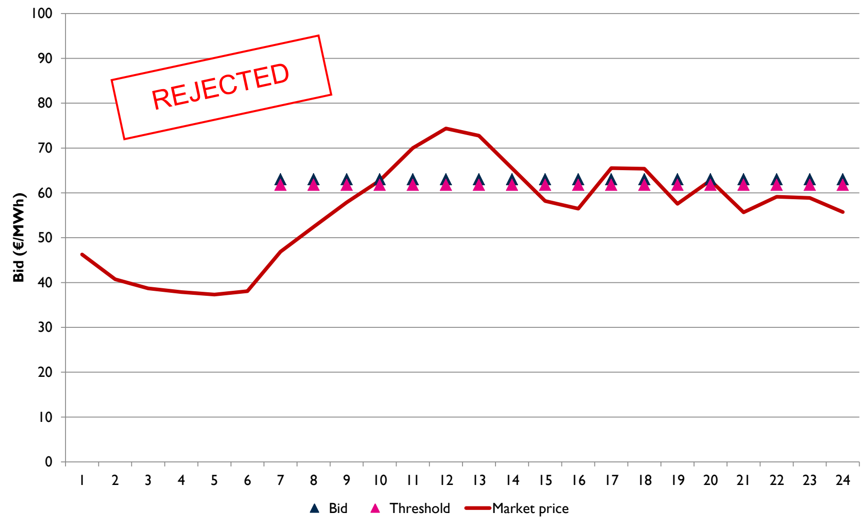
In this example, CCGT Unit A does not expect to be running at the start of the day. It submits a Profiled Block Order to EUPHEMIA, with the offer price reflecting its incremental, no load and start costs. The Profiled Block is 18 hours in duration, and allows for the plant to ramp down to MSG after the expected evening peak.

**Figure 4-3 Case 2 submitted Block Order for CCGT A**




On this characteristic summer day, the bid price for the Profiled Block Order is marginally above the threshold of the volume-weighted market price, and the order is rejected. Note that the incremental and no load costs of CCGT A are around 47 €/MWh at full load in this example, below the hourly market price for the duration of the Profiled Block Order. The block order is out-of-the-money in this case as a result of the internalisation of the assumed start costs.

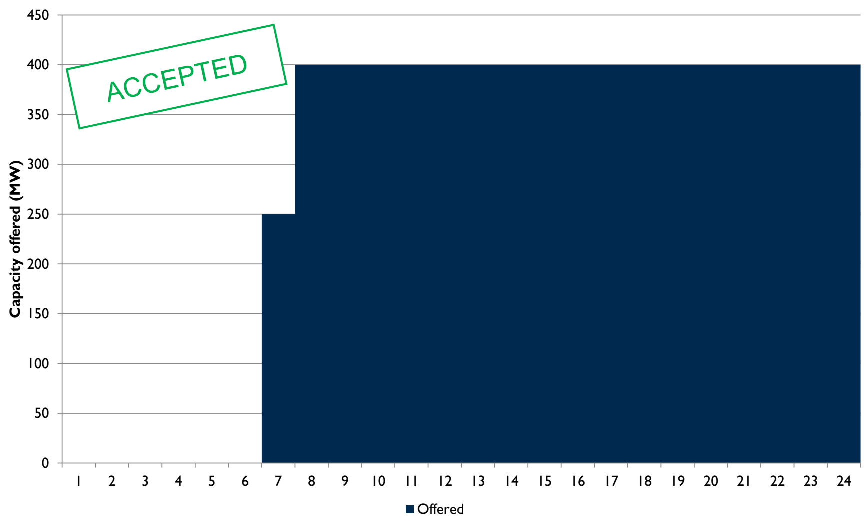
**Figure 4-4 Case 2 Block Order pricing for CCGT A**




Case 3: Profiled Block Order

Taking the same example as Case 2, let us consider an alternative Profiled Block Order, again 18 hours in duration but with the volume maintained at maximum capacity until the end of the day.

**Figure 4-5 Case 3 submitted Block Order for CCGT A**




Applying the same (exogenous) market price profile as before, the block offer price in this case is slightly below the volume-weighted average market price, and the order is accepted. The allocation of start costs is key to the comparison of Cases 2 and 3. Spreading start costs over a larger block volume reduces the profile bid price (by 1.5 €/MWh relative to Case 2), which makes the Block Order more competitive in Case 3. This is despite the fact that Case 2 is perhaps a more accurate representation of the likely running profile of mid-merit plant in the SEM.

These examples are of course schematic (and ignore the interaction between EUPHEMIA orders and price formation) but illustrate some of the challenges facing mid-merit generators, such as the potential need to second guess market requirements. These two examples are alternatives for representing the underlying commercial and technical characteristics of the plant and yet lead to different outcomes, and provide a good example of scheduling risk under the I-SEM. Linked Block Orders provide an alternative bidding option and may be better suited to handle uncertainty around off peak running patterns, as we explore below.

*Linked Block Order*

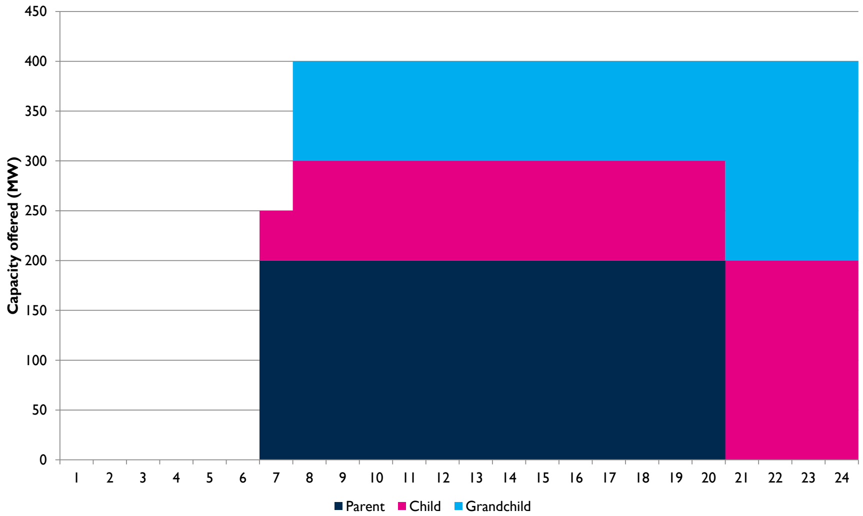
Case 4: Linked Block Order

Building on the example of Cases 2 and 3, let us consider how a Linked Block Order could be applied in this scenario instead of a Profiled Block Order. Taking the same overall availability profile as Case 3, a Linked Block Order could comprise a parent block at the MSG level of 200 MW for an extended period (14 hours here). Incremental output up to 300 MW is represented by one or more child blocks, with additional grandchild blocks reflecting incremental costs at the maximum capacity of 400 MW. A single child block at MSG covers the final 4 hours of the day, with incremental output represented by one or more grandchild blocks.

As noted above, day-ahead market operators in other jurisdictions using EUPHEMIA have placed limitations on participants' use of Linked Block Orders, which would rule out some of the formulations we have developed in these case studies. In principle, the flexibility of mid-merit generators to vary their output profile above MSG could be offered to the market as a 'strip' of hourly child blocks for incremental output above the parent block. In practice, participants in, for example, EPEX, are restricted to one child block per parent. If similar bidding restrictions are imposed in the I-SEM, generators will be limited in their ability to adequately incorporate their technical and commercial characteristics within their day-ahead orders.

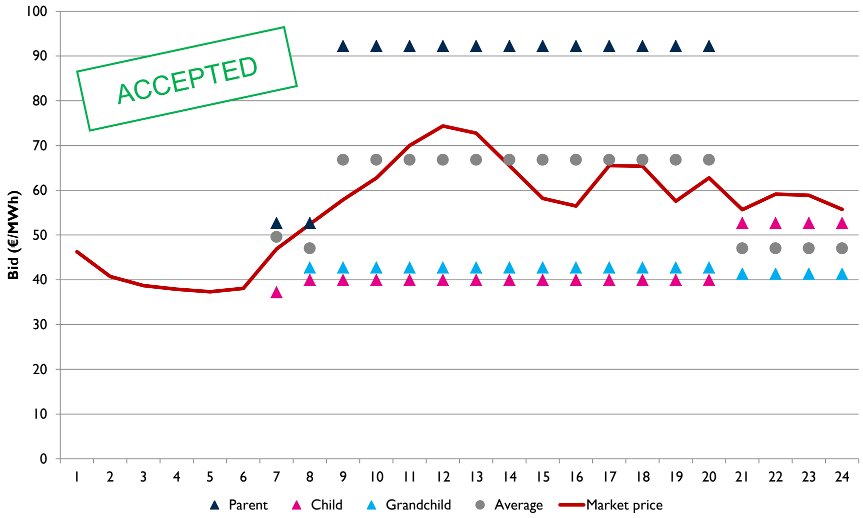
The Linked Block Order structure for this day is illustrated below.

**Figure 4-6 Case 4 submitted Block Order for CCGT A**




In this example, we assume that the start costs and no load costs for CCGT Unit A are fully allocated to the parent block (with no load costs for the final 4 hours allocated to the adjacent child block). Applying the same market price profile as the previous cases, the combination of parent, child and grandchild blocks is in-the-money and all blocks are accepted. The parent block, incorporating start costs, is out-of-the-money in this example, but this loss is outweighed by the positive margin on the child and grandchild blocks.

**Figure 4-7 Case 4 Block Order pricing for CCGT A**

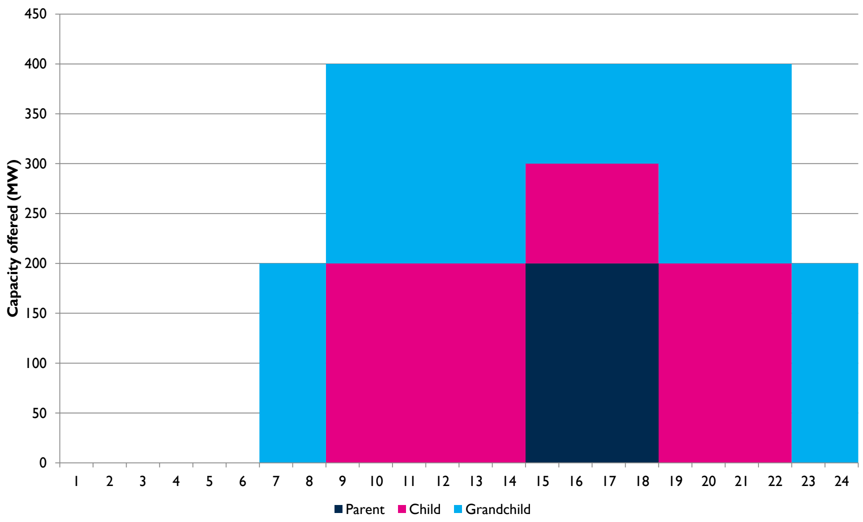



The Profiled and Linked Block Orders for CCGT A in Cases 3 and 4 are near-the-money. As a sensitivity, we found the block orders did not clear if the market clearing price was 1.2% lower across the day. This illustrates that CCGT A could be exposed to scheduling risk by having its block order paradoxically rejected by EUPHEMIA or of misjudging the timing of blocks and offer prices across the day.

<u>Case 5: Linked Block Order</u>

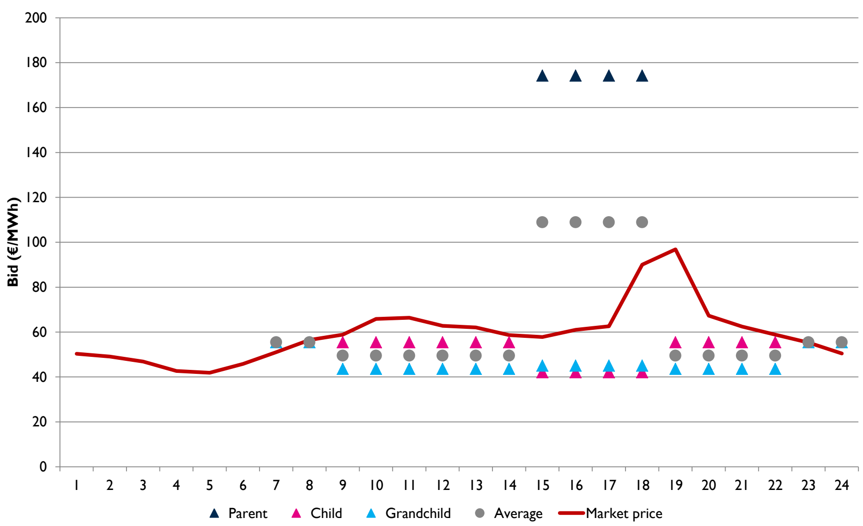
In this example, we construct a Linked Block Order for CCGT Unit A with the intention of presenting the most accurate representation of the unit's technical characteristics and cost structure. In a sense, this is analogous to the bidding methodology in the current SEM trading arrangements. The duration of the parent block matches the unit's minimum on time of 4 hours and the volume represents the unit's MSG of 200 MW. Start and no load costs are fully allocated to the parent block, such that any additional output can be offered at incremental cost. Child and grandchild blocks are then constructed for incremental output and for adjacent periods, as illustrated below.

### Figure 4-8 Case 5 submitted Block Order for CCGT A



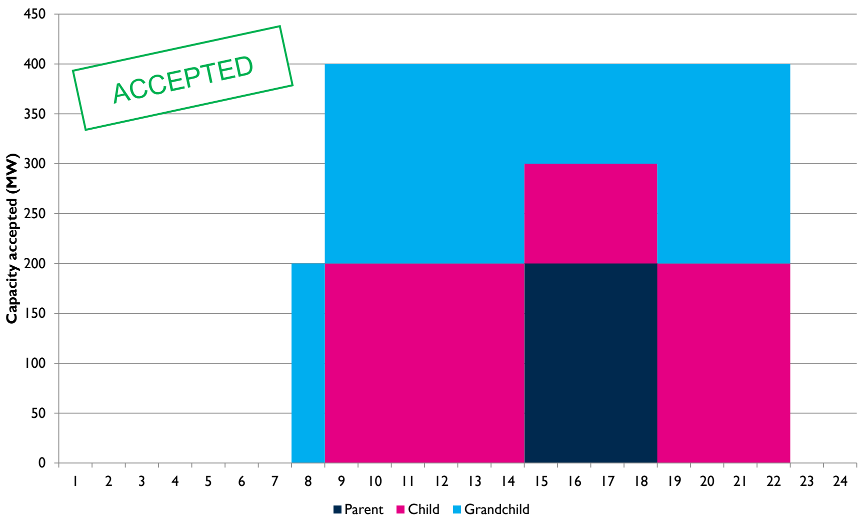

Given our cost assumptions, the parent block in this example is priced at 174 €/MWh. Applying a market price profile for a characteristic winter day, we find that the parent block is out-of-the-money. However, the combination of the parent, child and some grandchild blocks is in-the-money in this example.

### Figure 4-9 Case 5 Block Order pricing for CCGT A




Note that the timing of the parent block in this case does not coincide with the period of highest outturn market prices. Ultimately this did not impact the acceptance outcome in this example (because the family of parent, child and grandchild blocks are considered in combination), but may have done so in other scenarios. In practice, the timing of peak prices in the SEM is likely to become less predictable, due to uncertainty in both the level of intermittent generation and its participation in the I-SEM DAM.

The resulting acceptance profile for CCGT A is as shown below.

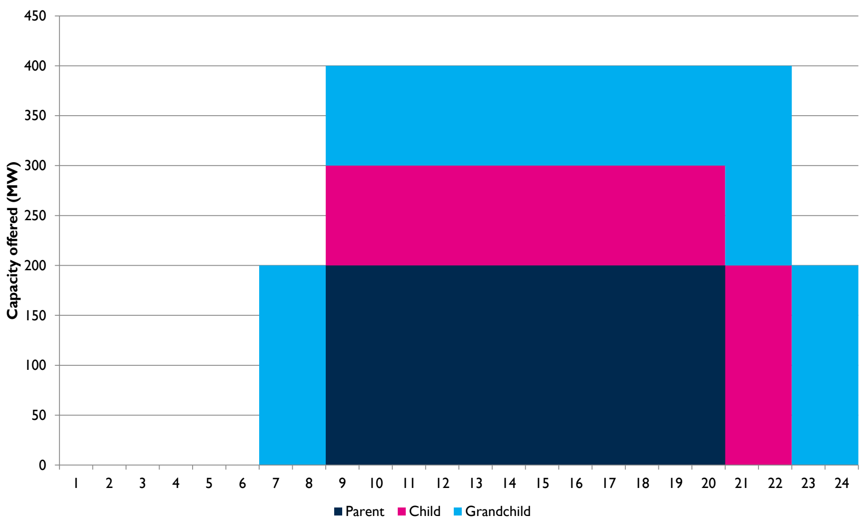



## Figure 4-10 Case 5 accepted order volumes for CCGT A

<u>Case 6: Linked Block Order</u>

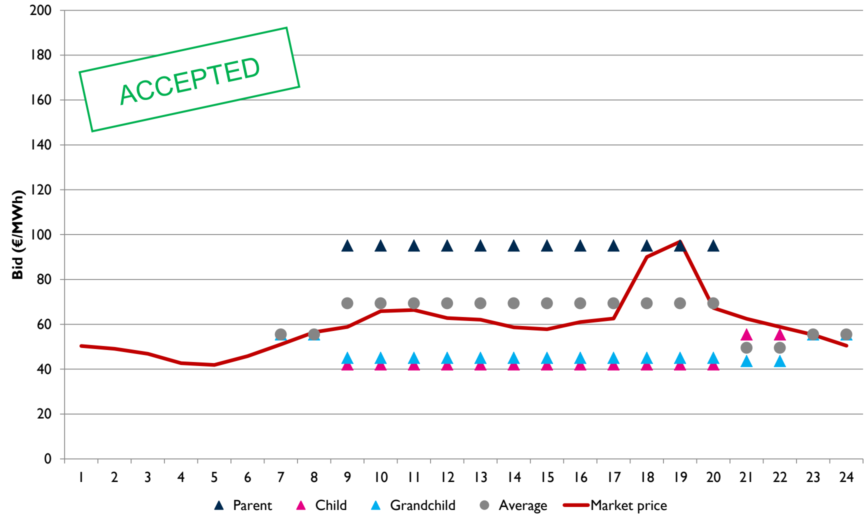
Building on Case 5, let us consider an alternative Linked Block Order using a larger parent block. Applying a 12 hour parent block allows start costs to be spread over a larger volume, potentially creating a more competitive bid price.

## Figure 4-11 Case 6 submitted Block Order for CCGT A




As in Case 5, we assume that start and no load costs are fully allocated to the parent, resulting in a parent block price of 95 €/MWh in this example.

**Figure 4-12 Case 6 Block Order pricing for CCGT A**




Applying the same exogenous market price profile, we obtain the same result in terms of accepted orders. Although margins on individual parent, child and grandchild blocks differ between Cases 5 and 6, the combined margin across the family of blocks does not. In practice, we would expect to see different outcomes in Cases 5 and 6 due to the interaction between near-the-money orders and price formation. Moreover, the mechanics of handling of complex configuration of block orders in EUPHEMIA may mean that the prospects of a paradoxically rejected order differ between the two cases.

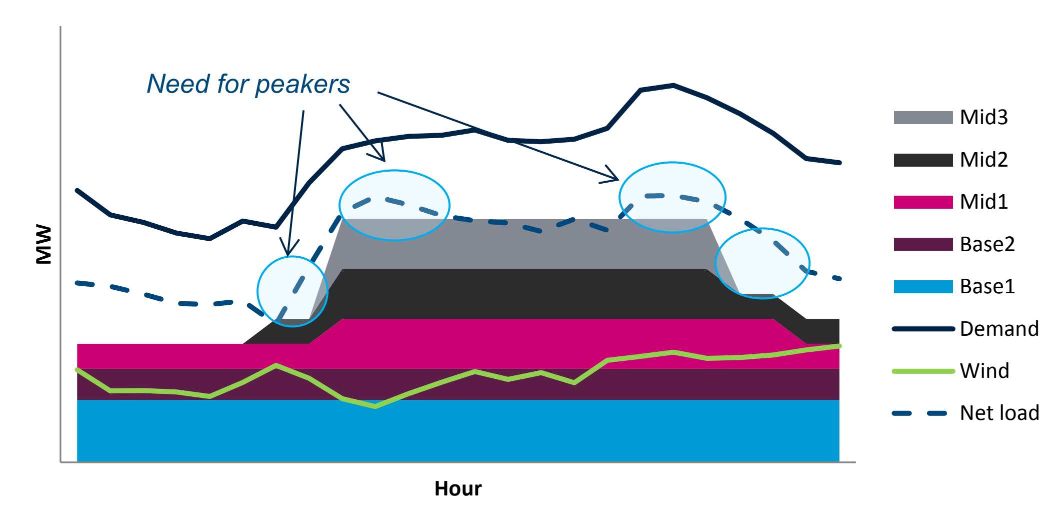
The Linked Block Orders for CCGT A in Cases 5 and 6 are near-the-money. We found that a 0.2% reduction in the market clearing price across the day would lead to the orders being rejected in these cases. Again this illustrates the sensitivity of the outcomes from the central dispatch algorithm to small differences in offer strategies and the potential for increased scheduling risk.

**Implications for system flexibility and predicting net load**

As we have illustrated in the case studies, baseload and mid-merit generators could potentially use Profiled or Linked Block Orders in the I-SEM day-ahead market to reflect their technical and commercial operating parameters. However, the use of block formats could reduce the flexibility offered to the market, relative to the current SEM arrangements, with generators opting to extend block durations and spread cost recovery. Flexibility may be reduced further by any limitations imposed on the order formats (e.g. a limit on the number of child blocks may prevent a strip of hourly orders being offered for output above the parent block level). Reduced flexibility from baseload and mid-merit market participants would place a greater reliance on peaking generators to ‘fill the gaps’ around the block orders.

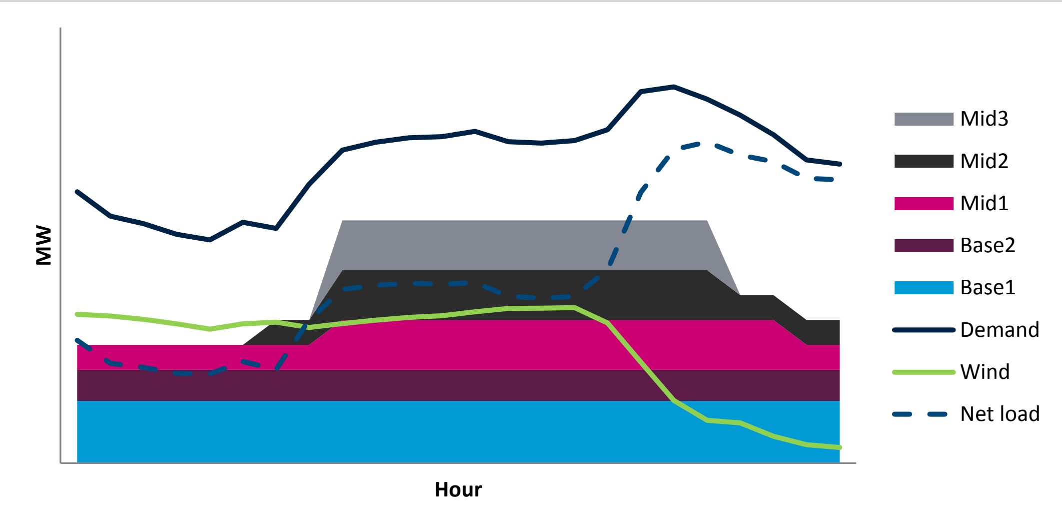
The schematic figure below illustrates how a combination of block orders from base and mid-merit generating units could stack up across the system relative to overall demand, net of wind generation. In this example, the combined profile of block orders broadly follows the system net load profile across the day, but more flexible (e.g. hourly) orders would be needed to match load in each hour. This reliance on flexible hourly orders is accentuated around the edges of the mid-merit blocks.

Figure 4-13 Block orders and system net load




Profiled and Linked Block Orders require participants to pre-determine the start and end times of each block. Participants are therefore at risk of misjudging their block timings and either failing to clear their orders or potentially under-recovering costs (if the profile of accepted orders differs from that expected for cost allocation purposes). With increasing variability in intermittent generation, the net load profile on some days may differ materially from the predicted demand shape. The figure below shows the same demand profiles and block orders with a different aggregate wind profile. Mid-merit block orders structured around day-time operation would be less likely to clear on this day than those supporting a later start and overnight operation.

Figure 4-14 Block orders and wind variability



Case 7: Linked Block Order

Our previous Linked Block Order examples have assumed:

- Start costs are fully allocated to the parent block
- No load costs are fully allocated to the first block (parent or child) in each hour.

Other bidding strategies could consider alternative allocations of start or no load costs, for example:

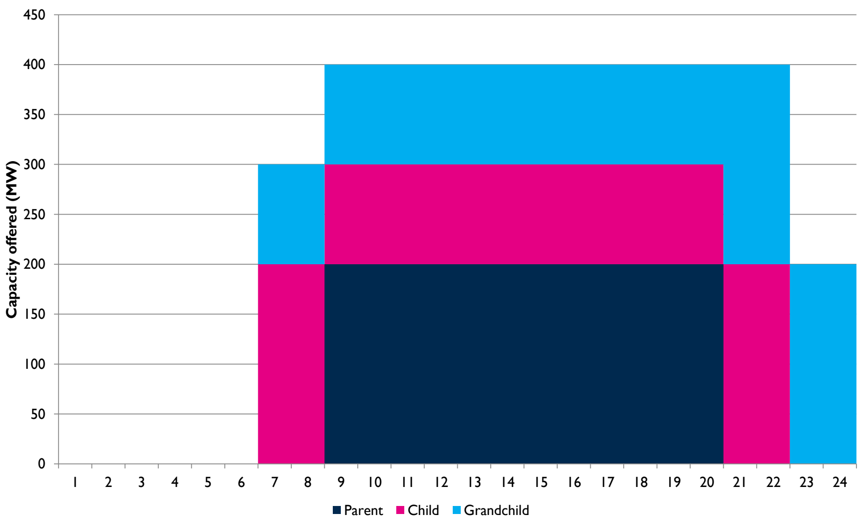
- To improve the competitiveness of the parent block price by allocating some start or no load costs to child and grandchild blocks
- To re-allocate costs between peak and off-peak periods, reducing the price of overnight blocks and potentially avoiding a shutdown

The risk of re-allocating costs away from the parent block or between hours is that some blocks may not be cleared, leading to the potential under-recovery of costs.

For Case 7, we consider a 12 hour parent block structure for CCGT A, as in Case 6. Start costs are fully allocated to the parent block, but no load costs are smeared across the parent, child and grandchild blocks. To improve the competitiveness of overnight pricing, a proportion of the no load costs for the final 2 periods are re-allocated to the grandchild blocks during peak periods (17 to 20).

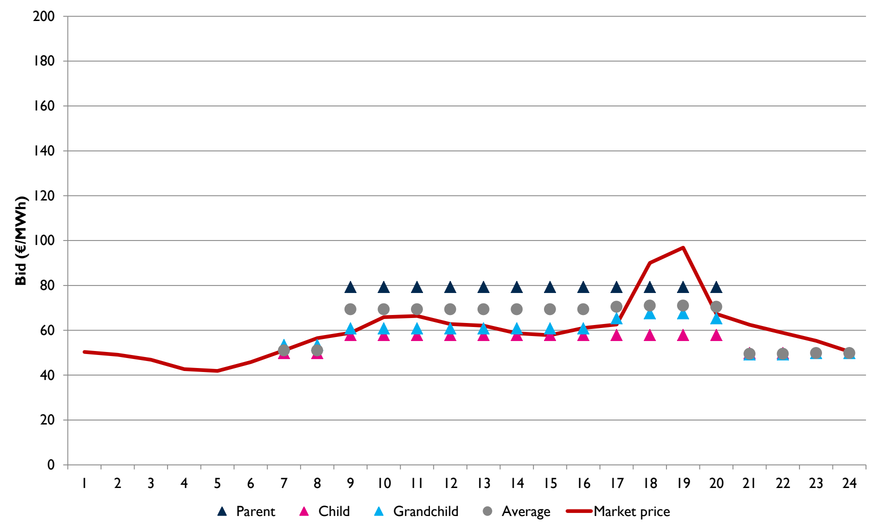
The submitted Linked Block Order structure is shown below.

**Figure 4-15 Case 7 submitted Block Order for CCGT A**




Having re-allocated a proportion of no load costs, the parent block price is reduced to 79 €/MWh in this example. Applying the same winter price profile, the parent block remains out-of-the-money but a combination of parent, child and grandchild blocks is cleared.

## Figure 4-16 Case 7 Block Order pricing for CCGT A

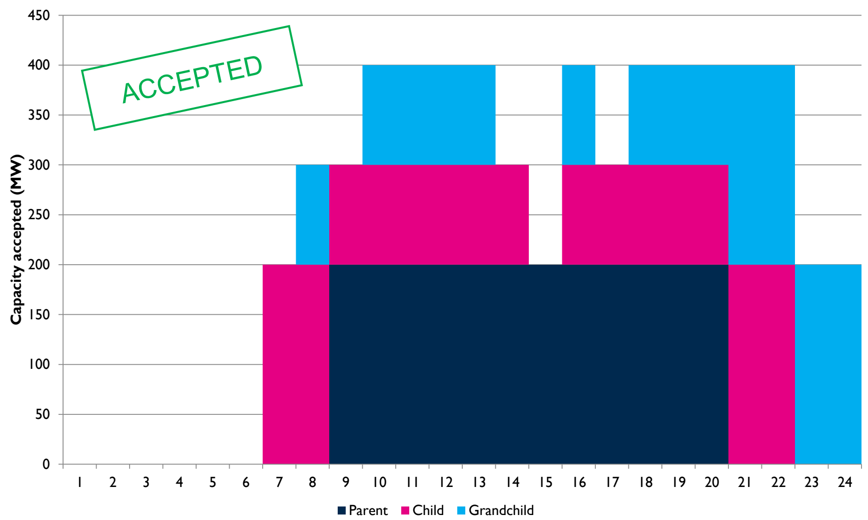



The resulting accepted offer profile is shown below. Compared to Case 6, we find that the addition of no load costs results in child or grandchild blocks not clearing in certain daytime periods (14,15,17). However, additional blocks are cleared during off-peak periods (7,8,23,24), potentially enabling the plant to avoid an overnight shutdown.

In this example, the operating costs for CCGT A are under-recovered by around €7,300 (due to the allocation of no load costs to blocks that were not cleared).

As a sensitivity, we found that a 0.6% reduction in the market clearing price across the day would lead to the family of Linked Block Orders being rejected. Orders would therefore be cleared at lower prices in Case 7 than Cases 5 and 6 for the same characteristic day, but this would result in cost under-recovery.

## Figure 4-17 Case 7 accepted order volumes for CCGT A



Case 7 illustrates how different operating outcomes and gross margins could be achieved by varying the allocation of start and no load costs between blocks. Participants may wish to explore a large range of pricing strategies to strike an appropriate balance between achieving a desired operating profile and ensuring cost recovery. However, it is likely that bidding strategies will need to evolve dynamically in response to changing market fundamentals and the actions of competitors.

Managing the scheduling risk associated with this dynamic spot market position will introduce additional complexity for independent generators compared to the current SEM arrangements, and may lead to participants seeking a higher risk premium on forward contracts.

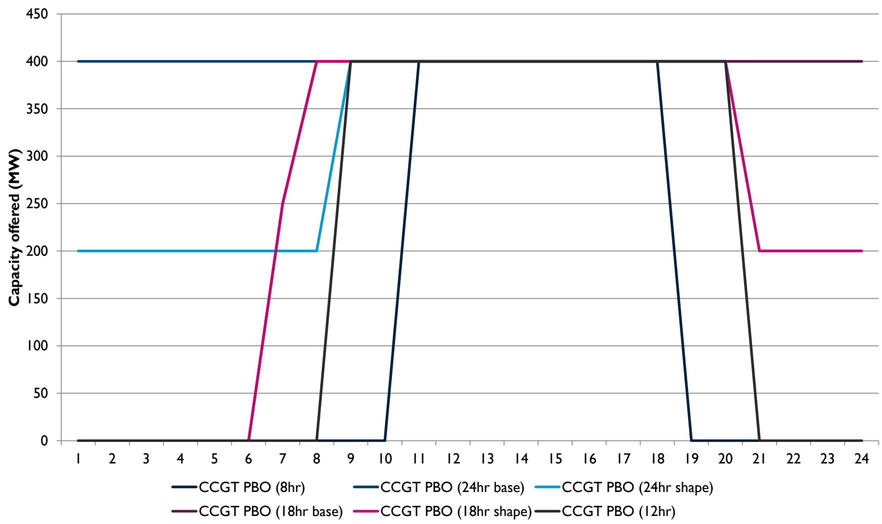
Case 8: Exclusive Groups

As the previous examples have illustrated, Profiled and Linked Block Orders require participants to make judgements regarding block start and end times, and to some extent, the relative competitiveness of their asset across the day. These judgements will be based in part on expectations of market fundamentals and the likely profile of clearing prices. With the increasing growth in intermittent renewables, we can envisage that historical relationships between electricity demand and market prices will no longer hold and the timing of daily peak prices will become less predictable.

Given these uncertainties, there is a risk that participants misjudge the timing of their Block Orders and they fail to clear. Exclusive Groups may help mid-merit generators mitigate this risk by allowing generators to submit a range of alternative operating profiles, leaving the choice of the optimal schedule to be resolved by the EUPHEMIA algorithm. Conversely, Exclusive Groups cannot be combined with parent and child combinations, thus limiting the ability to represent other commercial and technical parameters.

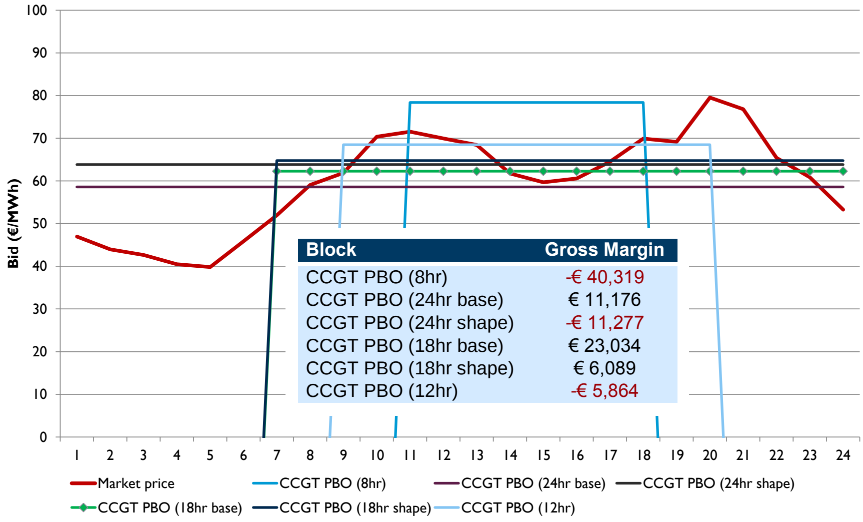
For Case 8, we assume that CCGT A submits an Exclusive Group of six Profiled Block Orders, ranging in duration from 8 to 24 hours. These orders are mutually exclusive, and each is priced to fully recover incremental, no load and start costs over the operating profile.

**Figure 4-18 Case 8 submitted Block Order Groups for CCGT A**



Applying a characteristic autumn price profile, three of the six Block Orders are out-of-the-money. If multiple blocks are in-the-money as in this case, EUPHEMIA will select the Block Order which maximises social welfare. Here we assume the accepted Block Order has the highest implied gross margin. This is a 18 hour base profile, as shown in Case 3.

### Figure 4-19 Case 8 Block Order pricing for CCGT A




## Peaking

Peaking plant are generally more flexible than mid-merit plant. This flexibility can be offered to the DAM using Simple Hourly Orders, assuming plant technical constraints are not binding (e.g. minimum on time of 1 hour or less).

Less flexible plant may consider applying Simple Block Orders, Profiled Block Orders or Linked Block Orders to ensure their technical constraints are adequately represented.

As with mid-merit generators, one of the challenges for peaking participants using Block Orders will be judging the most appropriate block timings for the market. Exclusive Groups may provide one solution to this problem. Flexible Block Orders also rely upon EUPHEMIA to optimise the timing of accepted orders from a market perspective, removing the need for participants to pre-determine their operating schedule. Flexible Block Orders may be particularly suitable for energy-limited resources, as well as demand response.

# 5. IMPLICATIONS

## 5.1. Introduction

In this section we lay out the implications of the I-SEM arrangements for scheduling risk, and the broader market impact. This draws on the illustrative examples explored in Section 4, but also takes into account a broader set of considerations, given the limitations of the simplified approach we have used for these.

## 5.2. Single Asset

**Reflecting flexibility and costs is not straightforward**

From the perspective of a single mid-merit asset, as the examples above demonstrate the I-SEM arrangements mean that it is not straightforward to reflect the technical characteristics and costs of the asset effectively through the available EUPHEMIA offer structures. This could be further exacerbated if there are limitations on how participants can apply the offer structures (such as limiting the number of children in a Linked Block Order). This means that a generator who has hedged forward will face scheduling risk in attempting to re-optimise a position at the day-ahead stage – as this could result in the asset not being scheduled in periods where prices clear above the cost of running the plant, creating a negative outcome relative to the hedged forward margin.

**Risk is greatly exacerbated without a liquid IDM**

This risk would be significantly mitigated if the DA market was accompanied by a liquid intraday market, actively trading from the publication of the DA auction results through to gate closure. This would enable generators to trade out positions from the DA swiftly at limited cost. In the long run the intent is for this to be provided by the harmonised European intraday trading platform, but the timeframe for that is unclear, and it is almost certain that this will not be in place for a material period of time following the introduction of I-SEM.

**Exclusive DAM also limits position management**

In no other European market is the DAM the exclusive route for physical trading. This means that market participants can manage their position through a combination of auction participation, standard bilateral trading, and structured products, enabling a much greater level of control, particularly important for mid-merit plant, even prior to the intra-day market, enabling further re-shaping and refinement. None of these will be options for I-SEM participants. Only under I-SEM would generators be reliant on the specifics of EUPHEMIA offer structures to reflect cost and flexibility.

**There is a possible incentive to zero-bid, reducing market efficiency**

A possible consequence of this is that mid-merit plant may choose to avoid this risk by 'zero-bidding' at the DA stage to match forward contracted positions, unless a less prescriptive version of the Bidding Code of Practice was retained in some format. This enables the plant to reduce scheduling risk and therefore risk to hedged margin. However, at times where the cost of generation for the plant was higher than the resulting clearing price, this would be neither an efficient market solution nor an optimal economic outcome for the plant.

**There may be an incentive to reduce the level of asset flexibility offered**

There are further consequences for a single asset that make the bidding strategy more difficult. There are clearly a reduced set of options for offering generation flexibly to the market compared to the current SEM. The need to recover start costs could lead to a tendency to offer longer duration 'blocks' than could be technically offered (such that the increment associated with the start cost is spread more widely). In addition, it is likely that there will be limits on the number of child blocks that could be offered, which could mean that a potential "hourly strip" of child blocks on a single parent block would need to be aggregated up.

**Risk of cost under-recovery depending on cost allocation in bidding strategy**

Further, the offer strategy for a single asset using Linked Block Orders will face choices about how to spread start-up and no load costs across the parent and child block prices. Loading the full possible start-up cost and no-load cost into the parent block increases the risk that the parent will be out-of-the-money, although these losses may be offset by positive margins on child blocks in determining the final clearing outcome. On the other hand, spreading no-load or start costs across child blocks increases the competitiveness of the parent block, but at the risk of cost under-recovery if child blocks are not cleared with the parent. The examples in Section 4 (albeit simplified through imposing an exogenous change to market price) demonstrated how sensitive offer acceptance could be. Taken together with the potential for paradoxically rejected bids this highlights the potential for significant scheduling risk associated with judgements around offer parameter choices.

**Risk associated with start-of-day state uncertainty will be reflected in balancing bids and offers**

A key uncertainty at the point of submission for DA offers is the running state of the asset at the start of the offer period. Whilst there will be a current traded position, there will still be uncertainty as to any balancing actions that may be executed in the interim. Offers will need to be made based on an assumed schedule. If a balancing bid or offer is then accepted, then additional costs may be incurred (for example, start costs if a balancing bid is accepted for the plant to turn off) and it is likely that the plant would seek to recover these through an appropriate premium (discount) on its balancing offer (bid).

**Generators cannot combine complex options and hence cannot mitigate all risks**

Given that participants will have to choose between the use of offering a set of alternative profiles, versus using a parent-child structure, this implies that they will need to weigh up the uncertainties associated with the within-day shape of prices against the uncertainties associated with accepted volume and duration (and corresponding risk of under-recovery). For example, on a day with significant uncertainty as to wind generation, and hence to the profile of net demand, the participant might choose to utilise a set of profiles to have alternative blocks covering different potential peak periods, rather than offering a parent that might turn out to have been set at a period of low net-demand. This suggests that additional information will be important, particularly in regard to wind and demand forecasts.

**Risk increased due to uncertainty in competitor strategies**

In developing an offer strategy, a generator will need to take into consideration the potential strategies that could be followed by competing generators. The issues outlined above are likely to drive diversity in strategies, and these are likely to evolve in a dynamic way in response to analysis of market outcomes (assuming that such strategies are relatively unconstrained by bidding principles). It is likely that market participants with sufficient resources will aim to model the EUPHEMIA algorithm to enable them to test and develop the sophistication of their strategies. So the scheduling risk inherent in the limitations in EUPHEMIA offer structures will be magnified by the uncertainty and potential instability in strategies applied by different competitors. This is compounded at times when GB and SEM price levels are similar as generators will then need to consider both SEM participant strategies and the potential level and shape of GB offers. Whilst it is difficult without conducting detailed modelling to compare the scheduling risk under current SEM arrangements (associated with the Uplift methodology) and under the proposed I-SEM arrangements, it could be that this “competitive strategy dynamic” leads to a higher degree of scheduling risk. It is possible that over time there could be some stabilisation as strategies mature, but a risk of a return to a more volatile environment will always be present.

## 5.3. Different technologies

**Risks are most material for mid-merit thermal assets**

For plant that are typically running baseload, or for wind (or other intermittent plant) with very low short-run costs, this risk is not relevant. For very flexible plant designed specifically as peakers (such as OCGTs), then the risk is low as these plant can have a more straightforward strategy of offering fully loaded hourly prices (whereby they would recover start costs even if they were scheduled for a single hour). The type of plant for which the risk is most material will be thermal plant that are at mid-merit positions in the stack – which could, depending on relative commodity and carbon price levels, be either gas or coal plant. This is likely to be a substantial subset of I-SEM installed thermal capacity given the high levels of wind generation in the I-SEM.

**Very flexible peaking plant may be beneficiaries**

Given the implications above for such plant, and in particular that there could be a tendency to create offer structures which are less flexible than under the SEM, that would suggest, as illustrated above, that peaking plant could be direct beneficiaries, as there could be more reliance on these assets to provide the hourly profile given the possibility of more ‘blocky’ offers from mid-merit plant. The impact of scheduling of peaking units (potentially at unintuitive times) could lead to price volatility increasing the market risk for other participants.

## 5.4. Asset portfolio

**Portfolio provides a diversity benefit**

As I-SEM requires unit level bidding, then similar considerations to those described above will be relevant for mid-merit assets within a broader portfolio. However, having a portfolio position is nevertheless likely to bring benefits. A portfolio player knows what the rest of its portfolio is doing with regards to commercial offers. In the context of the proposed High Level Design this provides an information advantage over a stand-alone generator who needs to guess this information to determine its most effective strategy. The advantage increases with the size of portfolio. In the current SEM this information asymmetry is managed through the Bidding Code of Practice which guarantees generators can compete on equal terms. However, without bidding principles it is very difficult to estimate the offer prices of competitors. Furthermore, it is not clear how unit-based bidding would in practice be interpreted where offers can be 'co-ordinated' across a portfolio. For example, with a hypothetical portfolio of three mid-merit plant, a strategy might involve zero-bidding for some volume of generation whilst offering capacity from other similar assets through parent/child offers placed at different times of the day.

We note that the High Level Design proposal for a single price cash-out means that longs and shorts in a generation portfolio will effectively net out. While unit bidding is proposed for the DAM and IDM, cash-out will be at a portfolio level. This would potentially advantage portfolio players and reduce within day liquidity, although other aspects of the detailed design may constrain participant behaviour from benefitting from this apparent anomaly.

**Complex algorithm likely to encourage complex portfolio strategies**

More generally, those players with a portfolio of assets are likely to be able to develop more sophisticated strategies over time, given the complex nature of the DAM in terms of offer structures and price setting. This may be especially true in a small market such as the I-SEM, where single plants represent a material share of the stack. It is likely that these players will aim to replicate the EUPHEMIA algorithm to develop and test these strategies, and assess the potential portfolio benefits in terms of an increased level of infra-marginal rent. It may prove very difficult from a regulatory perspective to distinguish between valid commercial strategies and strategies that are potentially anti-competitive or abuse a position of market power at certain times.

Given the potential for additional value to accrue to very flexible plant, then a portfolio with a significant proportion of such capacity could benefit.

## 5.5. Market clearing, balancing and dispatch

**Potential for artificial price spikes and troughs, and increased volatility**

We have discussed above the implications for a single asset or a group of assets. There is a further consideration as to how the combined strategies across the market may interact within the algorithm and how this could affect clearing prices in the auction. This is obviously contingent on the interaction between multiple strategies across different market participants, and is also likely to be dynamic, as strategies are evolved based on experience and observation of competitors. However, there is a concern that the consequence of strategies designed to mitigate scheduling risk, when translated across the market, could lead to inefficient outcomes. For example, if a material number of mid-merit plant were to zero-bid, this could exacerbate an issue that will face the market anyway as wind deployment increases, potentially leading to spuriously low prices at times, possibly combined with spikes as more peaking plant are required to create required shape. Such inefficient volatility is likely to deter forward trading and new investment, to the extent that prices are in part an outcome of the specifics of EUPHEMIA and associated strategies, rather than fundamental costs. In a similar manner, interconnector flows could be distorted in an inefficient manner.

**Mismatch between DAM schedule and feasible physical schedule could be exacerbated**

Given the nature of the EUPHEMIA algorithm, which was not designed to determine optimal physical dispatch, it is clear in any event that there is no guarantee that the result of the DA auction will be technically feasible, particularly for mid-merit plant. It is not yet clear in the I-SEM design how this will be managed (at least prior to any intra-day market) in terms of the steps to a feasible dispatch schedule that EirGrid can operate against. The types of issues discussed above could exacerbate this issue further.

### 5.6. Forward trading

**Potential impacts on forward liquidity**

Relative to the current SEM, the complete removal of bidding principles would mean in theory that an individual generator could ensure dispatch in the DAM to match a forward traded position by offering at a very low price below cost (assuming others were not doing the same). However, in doing so, it is likely to be reducing its expected earnings (since it will not be re-optimising at the day-ahead point, and since that strategy may restrict its ability to offer close to cost at other times), which could either deter forward hedging or result in an inefficient premium on forward prices. This could ultimately increase costs to consumers.

Further, to the extent that a material volume of mid-merit capacity did hedge forward, and then employed adapted DAM strategies to reduce scheduling risk, this could distort price formation in the DAM, in turn presenting a concern for the further development of liquidity.

Forward liquidity may also be impacted by uncertainty around price setting in the DAM, given the volatile nature of prices that could emerge as a result of the dynamic evolution of participant bidding strategies and the clearing algorithm's handling of complex orders in a small market.

## 6. CONCLUSIONS

In this paper, we have highlighted a number of potential risks associated with using the EUPHEMIA algorithm as the primary mechanism for scheduling plant, a concept without precedent in other European markets.

We believe that scheduling risk, present in the current SEM, is likely to endure and may increase under the proposed design, at least initially, impacting on forward market liquidity and prices. We have illustrated a number of examples that illustrate the potential risks. Uncertainty surrounding estimating the level of net demand and how to internalise start-up and no-load costs in offer structures represent the greatest challenge. The uncertainty is further compounded by the proposed relaxation of the Bidding Code of Practice which will make it more difficult to anticipate the offer strategies of competitors. In this respect, portfolio players will have a key advantage.

Given that the primary requirement for a liquid forward market is full confidence that the day-ahead index is reflective of supply/demand fundamentals, transparently derived, and free from potential distortion associated with particular participant strategies, we believe that the set of issues outlined in this document warrants careful consideration if this key objective of the new arrangements is to be met.

# Market Power and Liquidity in SEM

## A report for the CER and the Utility Regulator

15 December 2010

Prepared by:

**Cambridge Economic Policy Associates Ltd**

CEPA

## Contents

## EXECUTIVE SUMMARY

### Introduction

This report has been prepared by Cambridge Economic Policy Associates Ltd (CEPA) and assesses the evolution of competition in the SEM, the appropriateness of the current market mitigation strategy and the outlook for contract market liquidity. As such, the report builds on the analysis presented by the Regulatory Authorities ('RAs') in the August 2010 paper "SEM Market Power and Liquidity State of the Nation Review" ('the State of the Nation Review')[1] and the responses to that publication. The RAs have also asked CEPA to consider ESB's proposals regarding horizontal and vertical reintegration and the associated liquidity undertakings.

The SEM, in its design as a gross mandatory pool, has limited potential for spot market power. However, at its inception, given the dominant positions of ESB and Viridian, the RAs decided to put in place a package of mitigants to prevent abuse of market power and to encourage competition in the wholesale market. The package included the Bidding Code of Practice ('BCoP'), the Market Monitoring Unit ('MMU'), Directed Contracts ('DCs') and the Economic Purchasing Obligations ('EPO'), as well as measures to address local market power where needed.

### Overview of mitigation measures and scenario analysis

The market design and the associated mitigation measures appear to be working well. Reserve margins are high, although in part due to falling demand, and our examination of (falling) profitability in the SEM does not point to any abuse of market power – although some caution is required as falling profits seem to have been driven by falling gas prices rather than the entry of new price-setting plant or enhanced regulatory supervision (through the MMU).

We have also considered how competition will develop in the market, looking ahead to 2015 and 2020, and with forecasts of demand and generation investment based on what is expected in the 2010 Generation Adequacy Report and the "Gate 3" transmission access process. We have then used the Herfindahl-Hirschman-Index (HHI), which measures market concentration, and our preferred measure of the Residual Supply Index (RSI), which uses a continuous scale to examine whether a generator is 'pivotal', to inform an assessment of the potential for a generator to exert market power as the market develops in the chosen scenarios.

Our RSI analysis sets out the frequency of periods in which the system is not able to balance supply with demand without the supply of the 'investigated' market participant. For each scenario, we considered the position of ESB as a stand-alone generator (ESB PG), ESB as a horizontally integrated group (ESB PG and ESBI), ESB as a horizontally and vertically integrated group and of AES. We have also netted out an estimated level of Directed Contracts based on the current methodology which reduces the HHI to 1150 by requiring the larger generators to contract a portion of their expected output.

[1] http://www.allislandproject.org/GetAttachment.aspx?id=e83a335f-8366-416c-a6fe-96a0d54b1721

In all cases, the RSI remains above the selected 1.2 threshold when averaged. It is nevertheless interesting to note that it also drops below 1.1 in more than 5% of cases and even below 1 in a number of situations examined. This is most likely to be due to the impact of the assumed rapid expansion of wind power in the SEM during the forecast period, as in periods of low wind generation generators with even modest market shares may become pivotal. This suggests that a robust market power mitigation strategy is likely to continue to have value for the foreseeable future.

**Review of market power mitigation strategy**

We have examined each of the mitigants in turn and considered their appropriateness, relative to other structural or behavioural measures.

The SEM is a capacity and energy market, such that generators receive revenue separately for making capacity available to the market irrespective of whether any electricity is generated and for the electricity that is actually generated. In part to avoid the risk of generators being rewarded twice for making capacity available, a BCoP was put in place that required generators to bid at Short Run Marginal Cost ('SRMC') in the energy part of the market. The RAs also established the MMU to monitor generators' compliance with the BCoP. Overall, we believe that the BCoP, together with the monitoring by the MMU, has been effective in ensuring that bids are made at or very close to their SRMC. We do, however, note that respondents to the State of the Nation Review make a good case for the MMU to be 'beefed up' such that it can be more proactive in investigating proscribed bidding behaviour including e.g. underbidding. But the apparent success of the SEM should not be taken to mean that the BCoP and MMU should be removed, as our analysis shows that there will still be potential for market abuse under a number of scenarios.

DCs require market participants who are considered to have market power in the wholesale market to forward contract a proportion of their output. DCs also contribute to the availability of hedges, which is of great importance to the electricity market as a whole. Retailers need to hedge their product offerings, especially given consumer preferences for longer term (greater than one month) offerings, and the imperfect fit of fuel market hedges for supply companies that do not have the natural hedge of a group generator. Respondents to the State of the Nation Review noted that whilst DCs are imperfect, they are necessary to promote competition given the relatively illiquid non-directed contract market. Respondents also noted the need for an improved range of DC offering.

Ring-fencing takes two forms: horizontal and vertical. Whilst the BCoP is considered effective, if there is a desire to move over time to a less regulated (and therefore by definition more competitive market), then allowing the horizontal integration of a dominant generator would have a potentially adverse impact on the evolution of competition in the near term, for example increasing the potential for anti-competitive bidding in the energy market. Whilst the BCoP remains in place though, the operational horizontal separation of ESB seems to have little value in promoting competition, whilst adding some cost to ESB, and thus an operational integration could be considered.

Vertical separation and the EPO again seem to have served a useful purpose, not least in encouraging new entry, and potential changes to these arrangements are discussed below.

## Liquidity

We have examined the outlook for contract liquidity in the SEM. Again, this builds on the State of the Nation Review, which provided data on the current state of hedging and liquidity in the SEM. As noted above, contract liquidity enables non-vertically integrated suppliers to effectively source energy and manage risk. It also allows generators to manage gross revenue, which can be important to shareholders.

It is difficult to predict how the traded volumes in contracts outside the DCs will evolve over the scenario period. There are, however, a number of positive factors including:

- the SEM has now been active for a sufficiently long period for its parties to have observed the features of the market in practice and become comfortable with spot price formation;
- the gross mandatory pool market system means spot-price discovery in the market is based on all the generating capacity; and
- the east-west interconnector will mean that the SEM will have significant interconnection and present potential arbitrage and entry opportunities from the GB market.

There are however also a number of potentially negative factors:

- the SEM market is relatively small by volume, raising questions as to whether trading parties will find it economic to participate;
- there are a limited number of domestic market participants;
- DCs may serve to reduce the potential demand for hedging products by suppliers; and
- the perception of strong incumbency with for example information advantages, as well as the potential for vertical ring-fencing to be removed for ESB group may deter entry.

It is important to keep in mind that trading in other markets has taken time to develop, and that interconnection could facilitate significant increases in liquidity, as well as to an extent compete away premiums of Non-Directed Contracts over DCs by providing additional volumes. This will however fundamentally be dependent on effective arrangement for interconnection.

## Policy options and recommendations

We have considered a range of policy options to promote competition under different potential structural scenarios for the SEM. These measures are both structural, i.e. making changes to the industry structure through, for example asset sales or change of ownership, and behavioural i.e. restricting and monitoring the behaviour of market participants.

## Option A: 'No removal of ring-fencing'

The option of 'No removal of ring-fencing' of ESB companies, not surprisingly, offers the most favourable structure in terms of market power metrics with both concentration ratios and RSI outputs reducing as new CCGT and wind capacity is commissioned. In order to achieve even greater competition in the SEM, it could be desirable to see a reduction in the size of some of the existing parties, although our RSI analysis does not indicate that a non-competitive outcome would be very likely before any structural measure is in place. Additional structural change however significantly reduces the HHI. Under this option, it will be prudent to maintain the current market power mitigation package and to enhance the role of the MMU.

We have also considered how to promote liquidity. Under this option a potential strategy would be to reform DCs to help facilitate the development of a forward market. As market power metrics improve, it will not be reasonable to require ESB to support the market with contract offerings that are out of proportion to its market position – instead, under this scenario, market participants would need to view liquidity as a positive market outcome worth investing in as the volumes of DCs available to the market decline as the market becomes less concentrated. Furthermore, under this scenario ESB CS will have a strong incentive to encourage ESB PG to provide a greater range of contract products. In addition to this, there may be a case for adopting a specific policy on minimum levels of hedging from all generators, based on either a market power metric or market shares or to appoint a market maker.

We also think that under all scenarios market liquidity will benefit from an RA-led transparency programme for market data.

**Option B: Horizontal ring-fencing between ESB Group generating companies relaxed or removed**

Horizontal ring-fencing could take one of two forms: either full legal integration or an operational integration that allows the ESB generating companies to share and exchange information and a joint trading arm. Whilst the increased size of ESB as a generator is partially offset by new entry e.g. the Bord Gais Whitegate CCGT, as well as investment by Endesa, the modelled market metrics show that on balance market concentration is likely to remain at material levels and therefore measures to enhance competition and contract market liquidity will need to remain in place, including DC in their current form. As ESB CS will remain ring-fenced, it will continue to need to work with ESB's generation business to offer appropriate contracts, and if the EPO remains in place this offering will ensure a significant proportion of the market, which with the vertical integration of ESB may become internalised, remains contestable. Overall we would expect the appropriate measures to increase liquidity to be similar under this scenario to Option A, however, clearly the volumes of DCs would be expected to be higher as market concentration would be higher.

Under this scenario, options to increase competition are more problematic, although competition may well increase with the introduction of the East-West interconnection, assuming the market rules are changed to allow for effective competition from the GB BETTA market. As with option A, adopting a specific policy on minimum levels of hedging from all generators could be implemented to improve liquidity.

Overall, we see benefits in the form of efficiency savings in allowing operational horizontal integration, with limited risks so long as the BCoP remains in place. Legal integration may be more problematic, as this separation arguably has option value for any future change of ownership.

**Option C: Horizontal and vertical integration of ESB allowed**

Under this scenario ESB would vertically and horizontally integrate, with ESB's supply business being fully backed by the capacity of both ESB PG and ESBI. Under this option, not surprisingly, the competitive starting point is significantly worse, both in terms of market concentration and RSI metrics. There are also significant potential impacts on retail market power, as, absent DCs, ESB would have little incentive to innovate in providing contract market liquidity. This, combined with a lesser incentive for the supply arm to purchase outside of the generation arm, may have a detrimental impact on other suppliers and end consumers through inefficient contracting, which may more than offset any operational efficiency savings from integration. Thus if vertical integration were to be allowed, there would need to be a review of the nature of tariff regulation in retail markets that are not competitive.

ESB has submitted a liquidity undertaking which would serve as a potentially positive step in proving volumes to the market, but this undertaking needs to be set against the potential adverse effects of reduced overall incentives to trade in the market and increased market concentration which severely limits the ability for the regulators to relax market mitigation and regulation in the market – both of which are seen by market participants as positive steps in encouraging liquidity to emerge. In addition, ring fencing and the EPO disappear, and it would be difficult to address the removal of an important structural remedy through behavioural measures alone.

It is further worth noting that under these conditions the market power mitigation strategy through the DCs ensures that the RSI stays above 1.2 in most scenarios as well as above 1.1 in during more than 95% of period. These metrics are though of course sensitive to assumptions for demand, interconnector flows and investment, all of which can have significant impact. In addition to this it can be argued that the impact of DCs is reduced if the vertically integrated ESB is allowed to take up the DCs it would be entitled to through the consumer load of ESB CS.

A preferable option under these conditions could be to balance the re-integration of ESB with structural divestment (into separate ownership) to help facilitate the development of liquidity and wholesale market competition. Such structural changes would however need to be carefully designed to ensure it delivers a competitive outcome. In this regard we understand that the Irish Minister for Finance has appointed "The Review Group on State Assets and Liabilities" to consider, inter alia, the potential for asset disposal in the Public Sector including commercial State Sponsored Bodies. Another alternative would be to create two separately ring-fenced vertically integrated entities to reduce ESB's market share. This would allow the benefits of vertical integration while also promoting competition between the two entities.

**Conclusion**

The SEM wholesale market appears to be working well. Competition is increasing, in part due to the current market mitigation strategy. With significant market developments in the near-term (mainly interconnection, potentially bringing competition from GB once appropriate access arrangements are in place, and increased wind penetration), we consider it prudent not to implement ESB vertical integration in the near-term as that might damage competition, but instead to focus on enhancing measures to promote competition and improve liquidity.

# 1. INTRODUCTION

In August 2010 the RAs published the information paper the State of the Nation Review. The report presented market participants with a range of information including:

- An explanation of the rationale for, and function of, the existing market mitigation measures;
- A presentation of market data showing how the composition of the SEM has evolved since its start almost three years ago;
- A presentation of market power metrics and how these have evolved; and
- A presentation of the current and historical availability of contracts and contract liquidity in the SEM.

The State of the Nation Review asked for the views of market participants on a range of issues across the topics of market power and liquidity in the SEM.

Following on from the State of the Nation Review, the RAs have commissioned a study by CEPA to assess how competition can be promoted in the SEM. This has focused on the appropriateness and need for the market power mitigation strategy, with an emphasis on how it, through its components could be amended to promote competition. It is important to note from the outset that the market power mitigation strategy was intended to be a "package" of measures, and thus when assessing the individual measures they are always, unless otherwise stated, considered as being discussed within the context of the other measures remaining in their current form.

We have also examined the outlook for contract market liquidity in the SEM. We consider that liquidity is a desirable and important feature of a competitive market. We note that liquidity is not an end in itself, to be accomplished at any cost, but rather a feature that, if it exists, will help enhance competition across the electricity value chain.

## 1.1. Interactions with other work undertake by the Regulator Authorities

This workstream naturally interacts with other work being undertaken by the RAs. This includes work on price deregulation of the retail market in Republic of Ireland (RoI) and on day-ahead trading[2]. In this workstream, we have taken account of the The Roadmap to Deregulation (CER/10/058) ('The Roadmap') published in April 2010 and progress towards retail market price deregulation in the near term. The day-ahead trading project is, we understand, just commencing, so, whilst any interaction on liquidity impacts will be important, this is likely to happen during the consultation phase of this project.

## 1.2. Structure of report

The remainder of this report is structured as follows:

[2] Please see annex 2 for details.

- Section 2 sets out background to the market power mitigation strategy, its objectives, and the context within which it was designed. This section complements the fuller outline provided in the State of the Nation Review.
- Section 3 presents a brief overview of the market power measures referred to through this paper - this again complements the analysis already presented as part of the State of the Nation Review.
- Section 4 presents an assessment of the market power mitigation strategy adopted so far in the SEM.
- Section 5 outlines an assessment of the current drivers of contact market liquidity in the SEM, as well as an evaluation of what the drivers will be in the future.
- Section 6 sets out the policy options available to mitigate market power and to promote competition, and outlines the recommended changes to the market power mitigation strategy, as well as our proposals for measures to enhance contract liquidity in the SEM.

Annex 1 summarises the responses received to the questions raised in the State of the Nation report. The responses by market participants have informed this report.

Annex 2 provides a summary of the Terms of Reference for the Day-Ahead Trading work.

Annex 3 sets out higher level scenario metrics.

Annex 4 sets out sensitivity analysis undertaken and shows the impact on RSI curves.

Annex 5 sets out ESB's proposals.

Annex 6 sets out the modelling assumptions used.

Annex 7 provides the list of consultation questions, on which the RAs would welcome specific responses.

## 2. OBJECTIVES AND CRITERIA

Before we consider how the SEM market structures have evolved and consider the effectiveness of the Mitigation Strategy, we should first consider the regulatory objectives these are designed to achieve. In this section, we therefore set out the objectives of the RAs, as well as the objectives and design criteria behind the Market Power Mitigation Strategy. Further details behind the design criteria is available in the State of the Nation Review.

### 2.1. Introduction

The Market Power Mitigation Strategy was designed by the regulators of the SEM, CER and NIAUR, to mitigate certain features which they anticipated that the SEM market structure would have upon its inception. But before we consider the objectives and design criteria of the SEM it is first useful to consider the overall objectives and missions of the SEM Committee, as well as the RAs.

The objectives of the SEM Committee are outlined in box 2.1.

*Box 2.1 Objectives of the SEM Committee*[3]

| **Objectives of the SEM Committee** |
|---|
| …is to protect the interests of consumers of electricity in Northern Ireland and Ireland supplied by authorised persons, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the SEM.<br><br>Having regard to<br><br>(a) the need to secure that all reasonable demands for electricity in Northern Ireland and Ireland are met; and<br><br>(b) the need to secure that authorised persons are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity Order or the Energy Order or any corresponding provision of the law of Ireland; and<br><br>(c) the need to secure that the functions of the Department, the Authority, the Irish Minister and CER in relation to the SEM are exercised in a co-ordinated manner,<br><br>(d) the need to ensure transparent pricing in the SEM;<br><br>(e) the need to avoid unfair discrimination between consumers in Northern Ireland and consumers in Ireland. |

The objectives of the regulators need to be borne in mind, as the details of the Market Power Mitigation Strategy and any proposed changes will ultimately need to better fulfil these objectives.

[3] Set out in Section 9 of the Electricity Regulation (Amendment) (Single Electricity Market) Act 2007 and Section 9 of the Electricity(Single Wholesale Market) (Northern Ireland) Order 2007.

## 2.2. Objectives of the Market Power Mitigation Strategy

Due to the existence of two large electricity groups on the island - ESB and Viridian - the RAs considered that, in addition to the standard features of the SEM, a specific strategy would need to be implemented to mitigate market power and its potential abuse. The objectives of this strategy, as referred to in AIP-SEM-31-06, are:

- To prevent market participants from abusing their market power; and
- To maintain efficient incentives for new entry and exit. In particular, all market participants should see correct market signals and, where possible, have available to them a range of competitive strategies.

The secondary objectives are:

- To expose the incumbents to competitive pressure, which should lead to increased efficiencies; and
- Not to unfairly discriminate between new entrants and existing players.

The RAs considered in AIP/SEM/02/06 that any market power mitigation strategy should meet the criteria outline in box 2.2.

*Box 2.2 Criteria for the design of Market Power Mitigation Strategy*

| **Criteria** |
|---|
| *Effectiveness*<br><br>The market power mitigation measure should be effective at mitigating market power.<br><br>*Feasibility*<br><br>A market power mitigation mechanism which cannot be effectively applied by the RAs is of no value.<br><br>*Retention of the Profit Motive at the Margin*<br><br>Rate-of-return regulation eliminates the market power problem through elimination of the profitability of market power exploitation schemes. However it is the profit motive which in fact engenders improvements to customers which no regulatory scheme can achieve. Thus, whatever market power mitigation scheme is adopted, it should not eliminate the profit incentive.<br><br>*Allows for Innovative Strategy*<br><br>In order for competition to deliver benefits to consumers, market participants should have as wide a set of strategies to employ as possible. Any market power mitigation scheme will limit the strategies available to market participants to some extent but, ideally and where possible, only those strategies which are directed to the exercise of market power should be limited while allowing all others. Given a choice between two otherwise equivalent schemes in terms of their ability to control the exercise of market power, the RAs aim to choose the one which leaves the most scope for important economic choices to be made by all market participants. |

*Regulatory Efficiency*

The selected market power mitigation scheme should not be an excessively difficult or expensive one to implement. More generally, any market power mitigation scheme ought to achieve benefits in excess of its costs.

*Flexibility*

The mitigation scheme must have the flexibility to deal with surprises in the SEM, whatever they turn out to be.

*Transparency*

As much as possible, the mitigation scheme should be transparent. Generators should know what is expected of them; whether or not they perform up to those expectations ought to be simple to monitor.

*Ability to Sunset*

If conditions warrant removal of a particular market power mitigation scheme, it should be removed and if possible, the conditions under which such a scheme will be removed should be stated in advance.

*Impact on Retail Markets*

The implementation of a market power mitigation strategy needs to take account of the method of PES regulation

The proposals we develop throughout this paper keep these criteria and the objectives of the regulators at their heart. The assessment and policy options we develop in this paper build on these objectives by considering how the objectives and can potentially be better fulfilled, reflecting both the experience for the SEM to date, and the outlook for the next 10 years.

# 3. ASSESSING MARKET POWER

## 3.1. Introduction

In this section we firstly briefly outline the basic concepts of market power and why it is considered harmful for consumers from an economic point of view and how the features of electricity as a product has an impact on the assessment of market power in these markets.

We then briefly outline the market power measures employed, including their strengths and weaknesses. It is important to note from the outset that indicators of market power do not necessarily suggest that market power is being used, or that it would be possible for the party to use it. Similarly, it should be noted that there are special features of electricity markets: in particular, that it is instant in nature, non-storable and demand is relatively unresponsive to price, and these features mean that it may be possible for market power to occur even when traditional indicators of market power, such as market shares or HHI's may suggest it would be unlikely to appear.

We then assess profitability in the SEM, and assess possible causes for the apparent decline. We then undertake RSI analysis to assess the impact of different options on market power.

## 3.2. Defining market power as a concept

When considering competition, it is important to specify the meaning of the concept "market power", as well as the related concepts of "substantial market power" and "dominance"[4].

Market power is an economic concept often linked to the legal concept of dominance. Dominance as a legal term derived from Article 102[5] of the European treaty. It is clarified in European case-law in particular through the "United Brands" ruling which specifies a position of dominance as:

> "The dominant position thus referred to by Article 86 relates to a position of economic strength enjoyed by an undertaking which enables it to prevent effective competition being maintained on the relevant market by affording it the power to behave to an appreciable extent independently of its competitors, customers and ultimately of its consumers." [6]

Dominance is a legal term, rather than an economic concept which can more easily be assessed. The corresponding economic term is usually a concept characterised as substantial market power. The link between the two concepts are explicit in the UK, and highlighted through working papers by the European Commission[7].

[4] Substantial market power and dominance are concepts of general competition law. It is important to note that in an electricity market context it is often argued that harm from market power may arise in circumstances not captured by the Article 102 of the EC treaty. For example, consider the market power case in Scotland considered by the GB regulator Ofgem, and the subsequent development of a Market Power Licence condition: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=42&refer=Markets/WhlMkts/CompandEff

[5] The current Article 102 was previously article 82 of the Treaty of Amsterdam, and before that Article 86 of the Treaty of Rome

[6] United Brands v Commission Case 27/76 1978

[7] DG COMP: DG Competition discussion paper on the application of Article 82 of the treaty to exclusionary abuse (DG Competition, December 2005)

More generally market power is described in guidance from the Office of Fair Trading (the GB competition authority), which is closely aligned statements by DG-COMP as:

> "Market power can be thought of as the ability profitably to sustain prices above competitive levels or to restrict output or quality below competitive levels. An undertaking with market power might also have the ability and incentive to harm the process of competition in other ways, for example by weakening existing competition, raising entry barriers or slowing innovation. However, although market power is not solely concerned with the ability of a supplier to raise prices, this guideline, for convenience, often refers to market power as the ability profitably to sustain prices above competitive levels."[8]

It is important to note that market power is not a black and white concept, but rather possessed by firms in a continuum ranging from perfect competition at one extreme to monopoly at the other. Some degree of market power exists in most markets and an important role for policymakers, competition authorities and regulators is to determine when it mandates intervention.

An important nuance to note is the need for a firm to be able to *profitably* sustain prices above the competitive level. This requirement also hints at longer term strategies whereby a party with market power may be able to exercise his market power to drive the competitor out of the market by offering his output at prices below cost. This strategy would, however, only be profitable if the party is able to recover the cost of the strategy once the competitor has left the market, by gaining the ability to for example withhold capacity. This would, for example, require some form of barrier to other competitors entering the market.

### 3.3. Market Power in Electricity

Assessing market power in electricity markets can be different from markets for many other products. Electricity as a product has several features that mean that particular care is needed to safeguard against abuse of market power concerns when competition is introduced in markets. There are several characteristics of electricity as a product and of transmission networks that are important to consider:

- It is an instantaneous product, as in order for the electricity network to operate it is necessary to maintain its frequency within a narrow band. This means that supply and demand on the system needs to be kept in balance in real time.
- It cannot be stored economically to a material extent. This means that production needs to be balanced to supply in real time, and arbitrage over time is limited. Systems with significant hydroelectric reservoirs are slightly different in this respect.
- Electricity markets have developed with a regional; or national scope and interconnection between networks is often limited.
- Demand is relatively unresponsive to price, particularly within day and often driven by seasonal and weather factors, rather than economic signals.

[8] OFT415: Assessment of market power:
http://www.oft.gov.uk/shared_oft/business_leaflets/ca98_guidelines/oft415.pdf

- Limitations to transmission capacity exist within electricity transmission networks.

These characteristics imply that the supply/demand situation and market conditions will change on a continuous basis and transmission constraints may mean that even within a network localised market power can arise, and move over time. For example outages in specific stations or circuits on a network may create situations whereby a specific powerstation is in a uniquely able or necessary to maintain the system frequency. If the station can predict when this will occur it implies that that it has the ability to raise the prices it asks for its production independently of other market participants.

### 3.4. Measures of market power in electricity

A range of both general and sector specific indicators and investigatory tools exist to detect market power. Many of these metrics are better suited to investigate the "raw" market structure – i.e. before taking into account the structural features of the SEM.

Some of these measures outlined are obviously less relevant in the SEM due to its design as a central dispatch market, and the existence of the Bidding Code of Practice ('BCoP'). It is nevertheless important to keep some of these in mind given that this project also considers ways in which the existing measures could be altered to facilitate competition.

It is important from the outset to note that metrics do not necessarily imply that a party has market power. In addition to this market power in electricity can materialise and be exploited even in contexts where metrics suggest there should not be a problem.

*Market Shares*

The most simple indicator or measure of market power is market share. The measure benefits from being readily understood and easy and transparent to calculate. By summing the market shares of the n largest (usually 4) participants in the market, a basic measure of market concentration is obtained. Market concentrations are relevant as fewer or larger market participants are considered to make it easier to exercise market power.

Market shares, concentration ratios and HHIs are calculated in the context of a defined "relevant market". A relevant market is commonly defined across several dimensions including:

- Product – such as energy production, baseload generation, short term capacity or long term capacity.
- Geography – is the relevant market the island of Ireland? Is it RoI and NI as separate markets? Or will it develop with interconnection and market coupling to become RoI, NI and GB as one market?
- Time – this last aspect is particular important given the non-storable and instant nature of electricity. This implies that electricity production during the morning hours are not substitutable with production in the afternoon peak hours (you generally[9] cannot buy the

[9] it should be noted that the storability question is slightly different in systems with a large quantity of hydroelectric capacity

former cheap and sell it for more in the later period). Similarly electricity production in the winter is not substitutable with production in the summer.

The traditional economic approach is to use the Small but Significant Non-transitory Increase in Price test (the "SSNIP-test") to define a market. The SSNIP test starts with the product of the party being investigated and asks the question "if the product held by the party was a market, would it be worth monopolising?" The way to answer this question is to examine if the party would be able to raise his price by a small amount (usually 5-10%) and profitably sustain the rise in price for a year. The definition is then expanded with the closest substitute until the narrowest possible definition where it is possible to profitably[10] raise prices by 5-10% is found.

It is however often difficult in practice to apply the SSNIP test and a potential alternative is to investigate market power under a range of scenarios characterising the more likely relevant markets. Consideration of market definition is nevertheless important in the context of the SEM as interconnection with GB increases during the next decade, both through the East-West interconnector, and the potential for expanding the export capacity to GB on the Moyle interconnector from the current 80MW to the full capacity of the interconnector of 450MW.

*Herfindahl-Hirschman Index (HHI)*

The Herfindahl-Hirschman-Index (HHI) measures the concentration in a relevant market. It is different from other concentration ratios as, rather than calculating the sum of the n largest firms in the market, it calculates the sum of the squared market shares of all market participants in a market. This yields a number between close to 0 and 10,000. The result is commonly characterised into three categories:

- HHI below 1,000 – unconcentrated;
- HHI between 1,000 and 1,800 – moderately concentrated; and
- HHI above 1,800 – highly concentrated.

By using the square of the market shares, rather than the actual shares, the HHI places additional weight on larger market shares than on lower ones and will highlight if a market is concentrated to a few large firms. One attraction of the HHI is that if firms act as Cournot oligopolists (that is, they decide on their supply to the market assuming that this has no impact on the supply decisions of their rivals), then the average Lerner Index (the output-weighted average of the price-cost margin as a proportion of the price) is proportional to the HHI and inversely proportional to the elasticity of market demand. This, however, ignores contract positions and makes strong assumptions about short-run bidding behaviour that may be a poor description of the way electricity wholesale markets operate.

*Pivotal supplier Indicator and Residual Supply Index*

The Pivotal Supplier Indicator (PSI) is an electricity specific indicator that makes an assessment that combines supply and demand conditions in the electricity markets. The PSI assesses if a particular generator is "pivotal" in serving demand. In other words it examines if demand could

[10] Profitably in this context suggests that the increased revenue from increasing prices outweigh the opposite effect of loss of sales as a result of the price increase.

be met without the capacity of that generator. The exercise is repeated for each period of the dataset being investigated.

The measure is, however, not without faults as it for example does not take into account contracting of stations (which would limit the ability of the generator to exercise his market power in practice). In addition to this, it does not address the potential for collusion or co-ordinated behaviour.

Some of the shortcomings of the PSI are addressed in the Residual Supply Index (RSI), which is an evolution of the former. While the PSI is a binary metric (you are either pivotal or not), the RSI uses a continuous scale. It is calculated as follows:

RSI = (System capacity (including import capability) – Uncommitted capacity of investigated generator) / demand

Uncommitted capacity here is that part of capacity that has not been contracted forward, and requiring an increase in the RSI for the investigated generator is equivalent to requiring an increase in its contract cover. If the RSI is below 115 then the capacity of the generator is necessary to meet demand (allowing for a planning reserve margin of 15%, otherwise it would be 100 + the required planning reserve margin). The ability to set a threshold is useful - however, similar to market shares and HHIs, there are no consensus rules as to what the critical value should be. Empirical studies in California suggests an RSI above 120% would result in a competitive market price outcome. In addition to this the studies undertaken as part of the European Commission Sector enquiry highlighted a critical value of at least 110% for 95% of the periods observed.

*Barriers to entry and Market Entry/Exit*

In addition to the metrics it also important to examine evidence for barriers to entry and expansion in a market. Low barriers to entry acts as an important check on competition and will help ensure that even large market participants will not be in a position to exercise market power. This means that where barriers to entry are relatively low, and there is a credible threat of entry, then even quite high market shares may not be a particular concern. In assessing the barriers to entry in a market it is useful to consider a range of different factors, including:

- Market liquidity: wholesale market liquidity can be a barrier to entry in a market as low liquidity may for example undermine the confidence market participants have in the price formation (and through that investment signals). It can also raise questions about the ability of participants to hedge their output and make entry by non-vertically integrated companies too risky.
- Compliance with trading arrangements and regulatory rules.
- Planning limitations and barriers to investment.

### 3.5. Market power and access to information

One very important way through which market power may be exercised is through the information advantages a large player will possess compared to smaller competitors. One of the premises upon which competitive markets are based is the requirement that all market participants have good (or perfect) information and that no party possesses an information advantage.

The specialised, and real time nature of electricity markets require that detailed, and timely information be available in order to enable market participants to take decisions in a timely manner. Absent information being made available to all on an equal basis a larger player may, through access to his large portfolio of generating stations, be in possession of information about plant availabilities, transmission outages and other factors that could enable it to take actions independently of its competitors. In many markets, including the SEM this type of advantage is often solved by requiring generators to make public the forecast maintenance plans for their plants, either directly, or through an agent. Critically access to transparent information also enables market participants to detect exploitation of market power by their competitors, and is therefore an important source of discipline in the market.

As we will discuss later in this paper information and transparency is also a very important feature to provide the confidence in the price formation necessary for liquidity to emerge.

### 3.6. Evolution of market power in the SEM

The MMU published a report in April 2009[11], which outlined the key developments of the SEM through to the end of 2008. Notably the report observed that:

- The highest SMP points coincided with highest demand periods during days;
- The movements of the SMP was in broad alignments with rises and falls in the underlying fuel prices and the carbon price;
- The SMP has tended to be inversely related to the available capacity margin; and
- The daily price profiles broadly follow the trends in GB balancing prices.

The report further undertook analysis of Pivotal Supplier Indexes which noted that one or more of the participants were pivotal (i.e. demand could not be met without their portfolio) in 65.8% of the period considered.

The MMU concluded that these observations were encouraging and that it suggested that the market design was working as expected. It further noted that much work had gone into the clarity of the BCoP and ensuring it is clear to interpret.

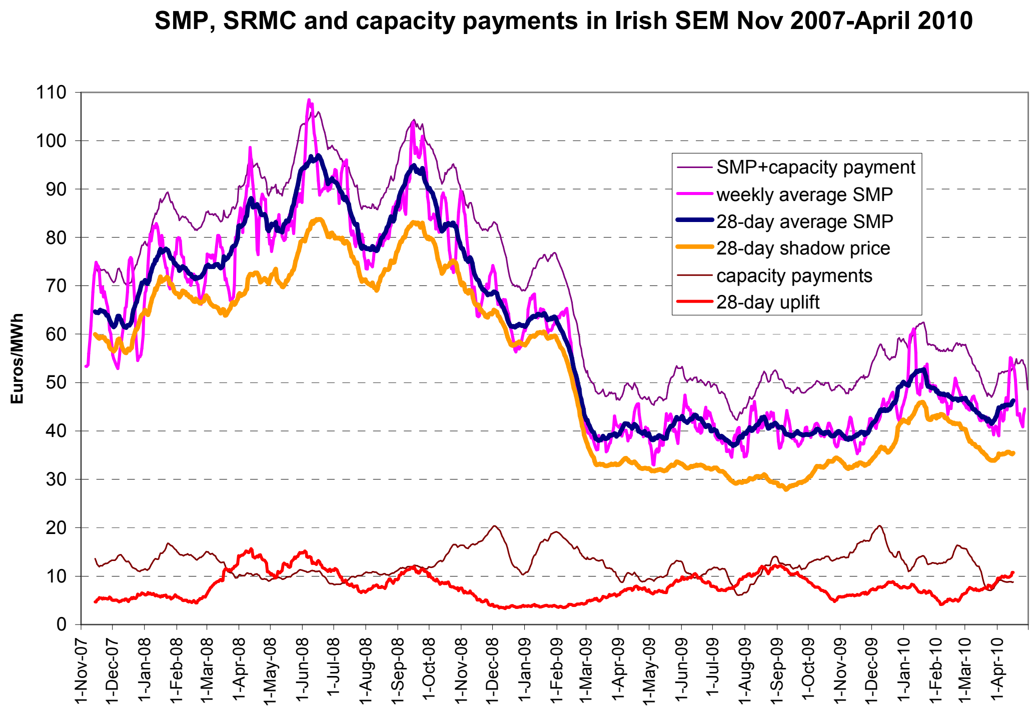
### 3.7. Evolution of profitability in the SEM

In most markets, one simple test of the presence or absence of market power, and more precisely, possible changes over time, is to examine corporate profit margins. In the SEM, market power is already heavily mitigated by the BCoP, but it is nonetheless worth examining recent trends in profits to see what trends emerge and what explanations might fit (ignoring for the time being any profits on contracts and assuming that all power is sold at the wholesale price).

[11] SEM/09/039 Market Monitoring Unit, Public Report 2009

Figure 3.1 below shows the weekly and 28-day averages for the shadow price, the uplift, their sum, the System Marginal Price (SMP), and the capacity payments that, when added to the SMP, determine the total payments to scheduled generators (those available but not dispatched just receive the capacity payment). It reveals a steady decline, but before concluding that profits have fallen with declining incumbent market share we need to examine fuel costs and other drivers of estimates of profits.

*Figure 3.1: Components of wholesale price, 7 and 28-day moving average (source: SEMO)*




There are a number of factors that might have driven any changes in gross profit margins, namely:

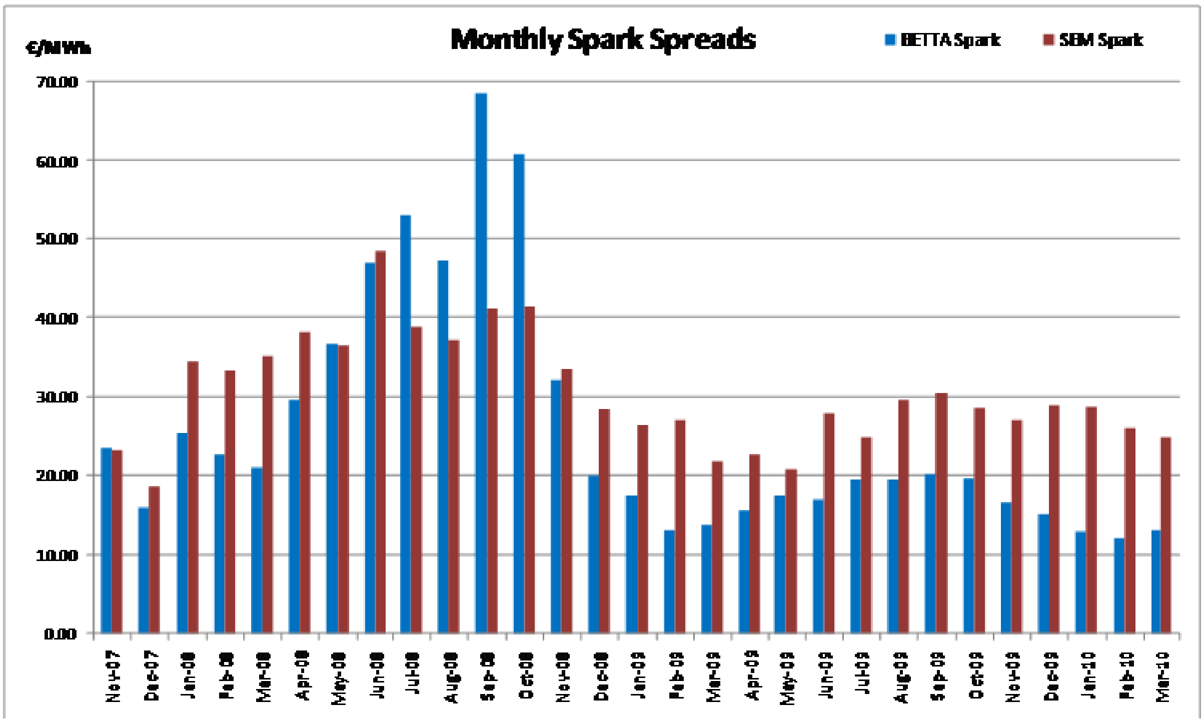
- Changes in fuel prices: in power generation markets, gross margins in part depend on fuel prices and relative heat rates. So, for example, if an OCGT is the marginal unit (i.e. the price setting unit) and gas prices fall, then the gross margin for a CCGT will decline in proportion to the relative heat rates.
- New generation has shifted the price-setting plant to plant with lower short-run marginal cost.
- Market monitoring is becoming more effective and is reducing opportunities to increase profits unreasonably.

We examine the first two factors further below. The last factor may in principle have been a driver, but the MMU has not as far as we are aware observed any unreasonable attempts to increase profits, so its actions are unlikely to have further reduced opportunities to increase profits.

### 3.7.1. Changes in fuel prices

The analysis provided in the State of the Nation Review showed that spark spreads (the wholesale price of electricity less the gas price, adjusting for the heat rate) have fallen since the peaks of mid-2008, as per Figure 3.2 below. This is likely to have been a major driver of declining profitability in the SEM, given the predominance of gas-fired generation.

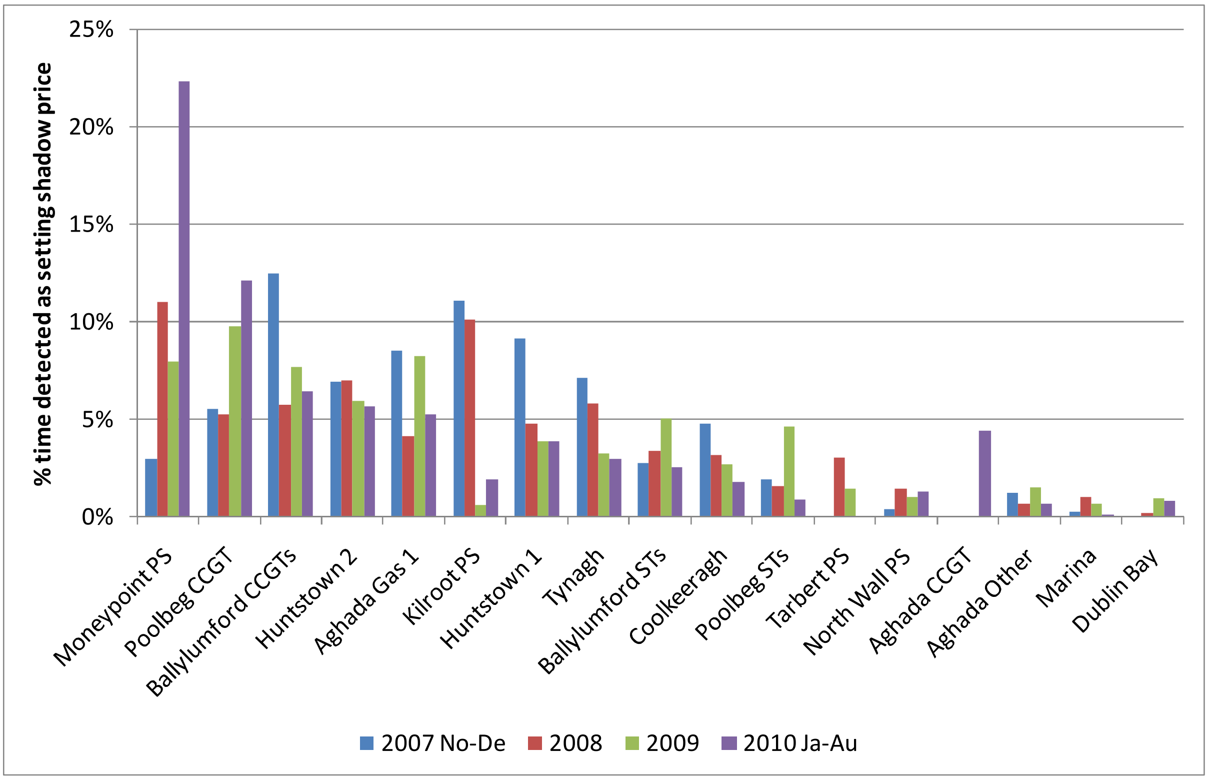
*Figure 3.2: Monthly spark spreads*




### 3.7.2. Changes in price-setting plant

Figure 3.3 shows which plants have set the SMP for what percentage of time between November 2007 and August 2010. It shows that there is considerable volatility in the percentage of time which any plant and indeed any fuel has set the SMP, with the main movements between gas-fired plants and coal-fired plants (Moneypoint and Kilroot). But it is apparent that on average, gas has been the price-setting fuel, although the spike in 2010 for Moneypoint (as the price setting plant) most likely reflects the relative movement between coal and gas. This would again point to changes in fuel prices being a major driver of changes in profitability for the SEM as a whole.

*Figure 3.3: Plants setting shadow price (source: SEMO)*




### 3.7.3. Assessment

It appears that gross profits have fallen significantly in the SEM since late 2008, which would not give a prima facia cause for concern that market power is being exercised. It seems likely that the major driver of falling gross profits was declining gas prices, rather than new entry of more efficient plant.

Caution is required, however, as falling profitability should not be taken to mean that there is no potential to exercise market power if the current mitigants are changed or removed.

## 3.8. Analysis of RSI in the SEM

In this section we outline analysis of RSI undertaken on a series of forward looking scenarios modelling market conditions in the SEM. The modelling was undertaken for the years 2015 and 2020, with demand and generation investment based on data from the 2010 GAR and Gate 3 transmission entry. The scenarios were modelled by the RAs through Plexos. A number of scenarios for input assumptions were prepared, these are outlined in Table 3.1 below.

*Table 3.1 Plexos input scenarios*

| Variable | Summary of Scenario |
|---|---|
| SEM Demand[12] | Low Growth 2.0% annually |

[12] The growth scenarios are based on the GAR. It should be noted that the high growth scenario was excluded due to further adverse economic developments since the 2010 GAR was published.

| | |
|---|---|
| Coal prices | A central and low case scenario for coal prices was modelled |
| GB interconnection | In order to model flows through the interconnectors with the GB the GB electricity market is modelled through a representative gas generator. To model the potential impact of different flows through the electricity interconnectors scenarios for a differentiating gas price, significantly lower and higher than the price of gas in the SEM was the input assumption for GB. |

The scenarios have the following higher level properties, as presented in Table 3.2. Additional higher level metrics from these scenarios are presented in Annex 3.

*Table 3.2 Higher level metrics of the SEM*

| Variable | 2015 | 2020 |
|---|---|---|
| Total Consumption | 39.81 TWh | 43.82 TWh |
| Wind Output | 11.07 TWh | 17.06 TWh |
| Peak Load | 7,971 MW | 8,700 MW |

For each combination of input scenario we calculated the RSI for the two largest generators in the SEM. We also calculated the RSI for a hypothetical, horizontally integrated ESB Group as well as the RSI for the ESB Group once the Directed Contracts (based on an HHI threshold of 1150) have been take into account.

The results of the RSI analysis for the 2015 and 2020 scenarios are presented in Figures 3.4 – 3.5. As outlined earlier, an RSI of more than 1.2 suggests a competitive outcome, while one below 1 suggests that the system is not able to balance supply with demand without the (uncontracted) supply of the investigated market participant. Thus, if a line in these charts intercepts the “1” axis at the 5% mark, it indicates that the market would not be able to balance without the capacity of that party in 5% of half hours in a year. It should be noted that the curves deducting the impact of the Directed Contracts are based on approximation and does not necessarily provide a fully accurate picture of the ability of Directed Contracts to mitigate against market power. In addition to these scenarios, a number of sensitivities around SEM prices relative to GB prices and coal prices relative to gas prices are included in Annex 4.

*Figure 3.4: RSI for 2015 low demand scenarios, high coal, and medium GB price*

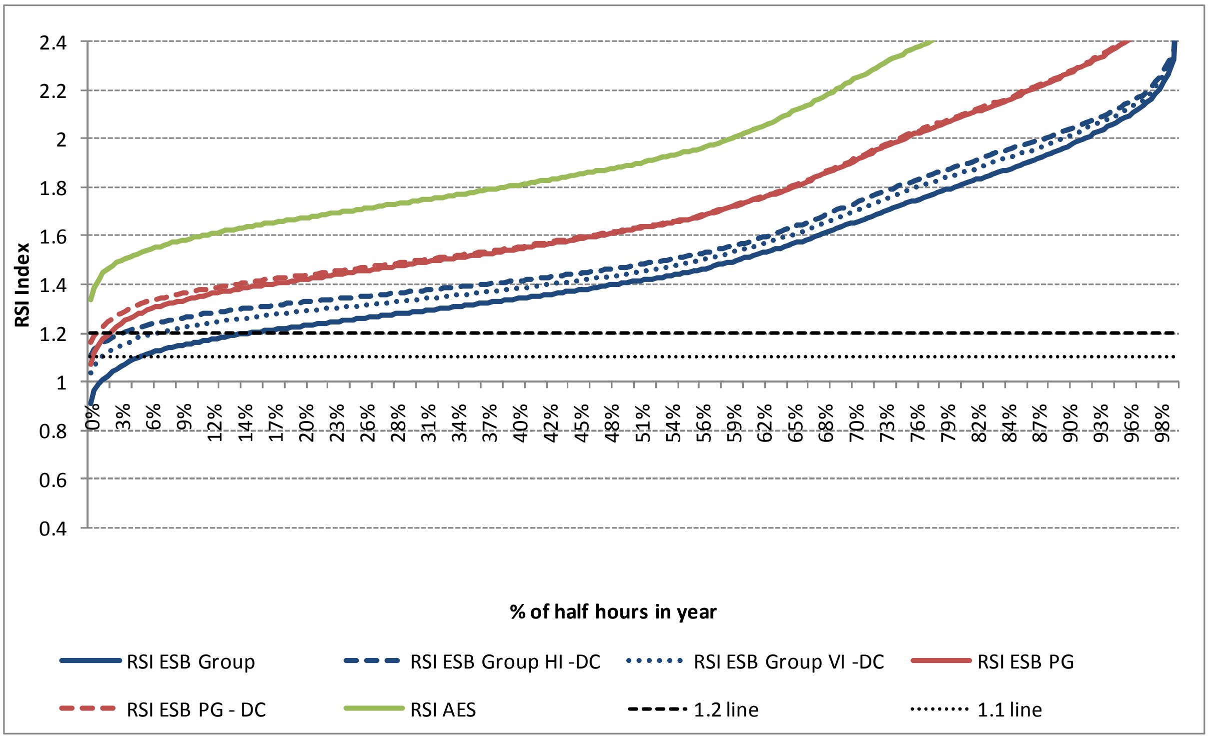
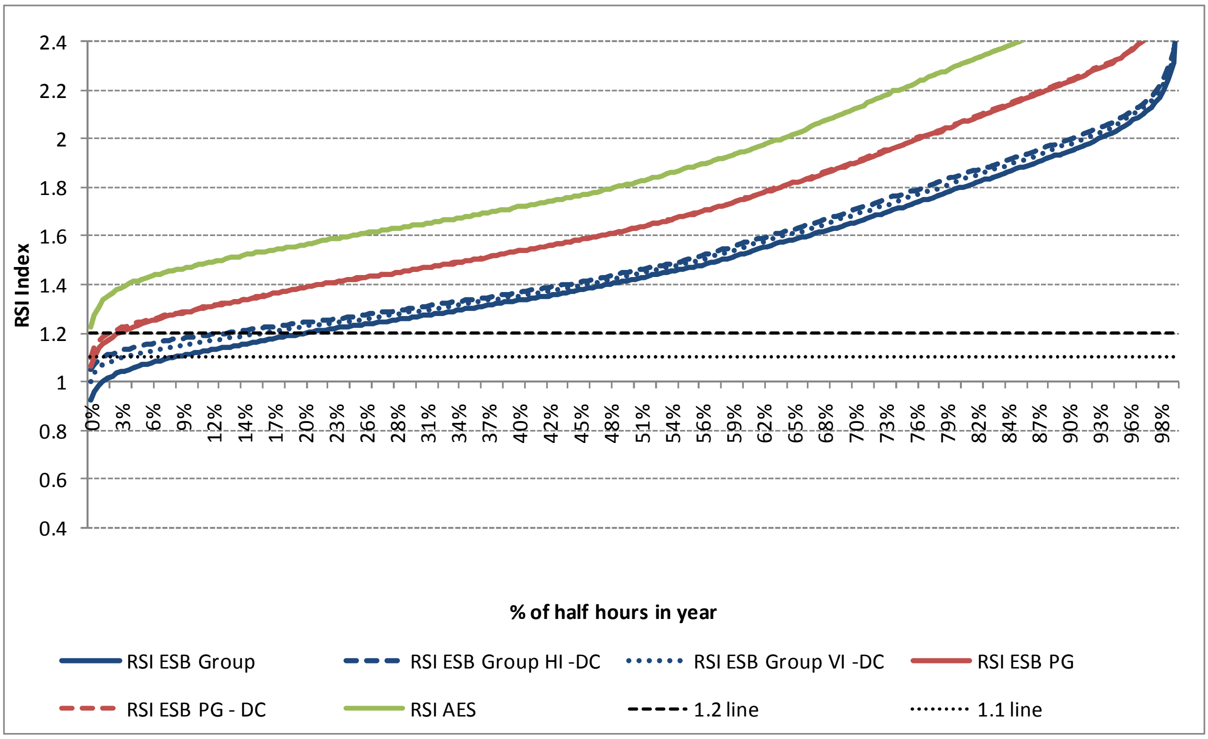



*Figure 3.5: RSI for 2020 low demand scenarios, high coal, and medium GB price*




The following approach has been taken in undertaking the calculations:

- ESB PG: This calculates the RSI for ESB PG with its current power generation portfolio. This line simulates the outcome before contracting has been taken into account.

- ESB PG – DC : This calculates the RSI for ESB PG with the simulated quantity of DC removed from the capacity to illustrate the impact on RSI of the DCs.

- ESB Group: This calculates the RSI for ESB Group under a scenario where ESB PG and ESBI integrate horizontally. Under this scenario the conventional generating capacity of both ESB PG and ESBI is included, as well as the renewable capacity grouped under ESBI.
- ESB Group HI – DC: This calculates the RSI for the horizontally integrated ESB Group (i.e. ESB PG + ESBI), net of the simulated volume of Directed Contracts which would be offered by such as grouping.
- ESB Group VI – DC: This calculates the RSI for the horizontally and vertically integrated ESB group net of the simulated volume of Directed Contracts such a grouping would be required to offer and net of volumes which ESB CS would be eligible for, with an adverse impact on the RSI metric.
- AES: This calculates the RSI for AES.

In both charts we have plotted the RSI for ESB PG, as well as when combined with the capacity of ESBI though horizontal integration. Since the ability of a party to affect the market outcome is also influenced by its contracting position we have also investigated the RSI of these generator groupings after the capacity estimated would be required to be contracted by them through DCs.[13]

In addition to Figures 3.4 and 3.5, Tables 3.3 – 3.8 provide an additional overview of the findings of the forward looking RSI analysis.

*Table 3.3 Average Half Hourly RSI for 2015 scenarios*

| Scenario | RSI ESB Group | RSI ESB Group HI net Directed Contracts | RSI ESB Group VI net Directed Contracts | RSI ESB PG | RSI ESB PG net Dicrected Contracts | RSI AES |
|---|---|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 1.28 | 1.35 | 1.32 | 1.47 | 1.48 | 1.72 |
| *High Coal price, Low Load, Medium GB price* | 1.50 | 1.58 | 1.55 | 1.73 | 1.74 | 2.03 |
| *High Coal price, Low Load, Low GB price* | 1.58 | 1.67 | 1.63 | 1.82 | 1.83 | 2.13 |
| *Low Coal price, Low Load, High GB price* | 1.28 | 1.35 | 1.32 | 1.47 | 1.48 | 1.72 |
| *Low Coal price, Low Load, Medium GB price* | 1.48 | 1.56 | 1.53 | 1.70 | 1.71 | 1.99 |
| *Low Coal price, Low Load, Low GB price* | 1.58 | 1.67 | 1.63 | 1.82 | 1.83 | 2.13 |

*Table 3.4 Percent of Half Hours the RSI is below 1.2 for 2015 scenarios*

| Scenario | RSI ESB Group | RSI ESB Group HI net Directed Contracts | RSI ESB Group VI net Directed Contracts | RSI ESB PG | RSI ESB PG net Dicrected Contracts | RSI AES |
|---|---|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 43% | 29% | 36% | 15% | 11% | 1% |
| *High Coal price, Low Load, Medium GB price* | 15% | 3% | 6% | 2% | 1% | 0% |
| *High Coal price, Low Load, Low GB price* | 12% | 3% | 5% | 2% | 1% | 0% |
| *Low Coal price, Low Load, High GB price* | 43% | 29% | 36% | 15% | 11% | 1% |
| *Low Coal price, Low Load, Medium GB price* | 18% | 4% | 8% | 2% | 1% | 0% |
| *Low Coal price, Low Load, Low GB price* | 12% | 3% | 5% | 2% | 1% | 0% |

*Table 3.5 Percent of Half Hours the RSI is below 1.1 for 2015 scenarios*

[13] Assuming an HHI Threshold level of 1150

| Scenario | RSI ESB Group | RSI ESB Group HI net Directed Contracts | RSI ESB Group VI net Directed Contracts | RSI ESB PG | RSI ESB PG net Dicrected Contracts | RSI AES |
|---|---|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 25% | 8% | 15% | 5% | 3% | 0% |
| *High Coal price, Low Load, Medium GB price* | 5% | 0% | 1% | 1% | 0% | 0% |
| *High Coal price, Low Load, Low GB price* | 4% | 0% | 1% | 1% | 0% | 0% |
| *Low Coal price, Low Load, High GB price* | 25% | 8% | 15% | 5% | 3% | 0% |
| *Low Coal price, Low Load, Medium GB price* | 6% | 0% | 2% | 1% | 0% | 0% |
| *Low Coal price, Low Load, Low GB price* | 4% | 0% | 1% | 1% | 0% | 0% |

*Table 3.6 Average Half Hourly RSI for 2020 scenarios*

| Scenario | RSI ESB Group | RSI ESB Group HI net Directed Contracts | RSI ESB Group VI net Directed Contracts | RSI ESB PG | RSI ESB PG net Dicrected Contracts | RSI AES |
|---|---|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 1.30 | 1.34 | 1.33 | 1.50 | 1.50 | 1.68 |
| *High Coal price, Low Load, Medium GB price* | 1.48 | 1.53 | 1.51 | 1.71 | 1.71 | 1.91 |
| *High Coal price, Low Load, Low GB price* | 1.57 | 1.62 | 1.60 | 1.80 | 1.81 | 2.02 |
| *Low Coal price, Low Load, High GB price* | 1.30 | 1.35 | 1.33 | 1.50 | 1.50 | 1.68 |
| *Low Coal price, Low Load, Medium GB price* | 1.46 | 1.51 | 1.49 | 1.68 | 1.68 | 1.88 |
| *Low Coal price, Low Load, Low GB price* | 1.57 | 1.62 | 1.60 | 1.80 | 1.81 | 2.02 |

*Table 3.7 Percent of Half Hours the RSI is below 1.2 for 2020 scenarios*

| Scenario | RSI ESB Group | RSI ESB Group HI net Directed Contracts | RSI ESB Group VI net Directed Contracts | RSI ESB PG | RSI ESB PG net Dicrected Contracts | RSI AES |
|---|---|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 40% | 35% | 37% | 16% | 16% | 3% |
| *High Coal price, Low Load, Medium GB price* | 20% | 13% | 16% | 3% | 2% | 0% |
| *High Coal price, Low Load, Low GB price* | 15% | 8% | 11% | 3% | 2% | 0% |
| *Low Coal price, Low Load, High GB price* | 39% | 35% | 37% | 16% | 16% | 3% |
| *Low Coal price, Low Load, Medium GB price* | 22% | 16% | 19% | 4% | 3% | 0% |
| *Low Coal price, Low Load, Low GB price* | 15% | 8% | 11% | 3% | 2% | 0% |

*Table 3.8 Percent of Half Hours the RSI is below 1.1 for 2020 scenarios*

| Scenario | RSI ESB Group | RSI ESB Group HI net Directed Contracts | RSI ESB Group VI net Directed Contracts | RSI ESB PG | RSI ESB PG net Dicrected Contracts | RSI AES |
|---|---|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 25% | 19% | 22% | 6% | 6% | 0% |
| *High Coal price, Low Load, Medium GB price* | 8% | 2% | 3% | 1% | 0% | 0% |
| *High Coal price, Low Load, Low GB price* | 6% | 1% | 3% | 1% | 0% | 0% |
| *Low Coal price, Low Load, High GB price* | 25% | 19% | 21% | 7% | 6% | 1% |
| *Low Coal price, Low Load, Medium GB price* | 10% | 2% | 5% | 1% | 0% | 0% |
| *Low Coal price, Low Load, Low GB price* | 6% | 1% | 3% | 1% | 0% | 0% |

In most cases the RSI will remain above the indicative 1.2 value when averaged. It is nevertheless interesting to note that it also drops below 1.2 and 1.1 in a significant number of cases and even below 1 in a number of scenarios examined. This feature is likely to be due to the impact of the rapid expansion of wind power in the SEM during the period studied. The increase in wind generation has the effect of:

- increasing the supply margin in a large number of cases; but
- in periods with low wind generation, generators even with a moderate market share may become pivotal for the supply of electricity in the SEM.

It is further apparent from the RSI analysis that the price difference between the SEM and GB has an important effect on the competitive conditions in the market, and this suggests that much of the spare capacity in the market may be concentrated in the larger generators, as when demand increases and the margin narrows, it increases the potential for large generators to exploit their market power. As we discuss further in Section 5.6, this is further supported by an increase in HHIs and required DCs when coal is an in-merit fuel. The variation of the HHIs and potential market shares of ESB for our 2015 scenario is illustrated in Table 3.9 and Table 3.10 for the 2020 scenario.

It is further interesting to note that under the combined vertical and horizontal integration of ESB, the analysis indicates that the current configuration of DCs alone may not be sufficient to ensure a competitive outcome as measured by the RSI analysis. It is nevertheless worth noting in these scenarios that the additional contracting done by ESB through its liquidity sell undertaking would further increase the proportion of output contracted in these scenarios, making it more difficult to profitably withhold capacity.

*Table 3.9HHIs and Market Shares for 2015 Scenarios*

| | HHI - no integration | HHI - horizontal integration | Market share of ESB PG | Market Share of ESB PG + ESBI |
|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 1073 | 1572 | 17% | 32% |
| *High Coal price, Low Load, Medium GB price* | 1112 | 1612 | 15% | 32% |
| *High Coal price, Low Load, Low GB price* | 1193 | 1682 | 15% | 31% |
| *Low Coal price, Low Load, High GB price* | 1300 | 1981 | 25% | 39% |
| *Low Coal price, Low Load, Medium GB price* | 1486 | 2118 | 28% | 39% |
| *Low Coal price, Low Load, Low GB price* | 1614 | 2031 | 29% | 37% |
| | | | | |
| *By capacity* | 1349 | 1873 | 28% | 38% |

*Table 3.10 HHIs and Market Shares for 2020 Scenarios*

| | HHI - no integration | HHI - horizontal integration | Market share of ESB PG | Market Share of ESB PG + ESBI |
|---|---|---|---|---|
| *High Coal price, Low Load, High GB price* | 984 | 1356 | 14% | 27% |
| *High Coal price, Low Load, Medium GB price* | 1043 | 1412 | 13% | 27% |
| *High Coal price, Low Load, Low GB price* | 1135 | 1484 | 12% | 25% |
| *Low Coal price, Low Load, High GB price* | 1200 | 1732 | 22% | 34% |
| *Low Coal price, Low Load, Medium GB price* | 1318 | 1784 | 23% | 33% |
| *Low Coal price, Low Load, Low GB price* | 1468 | 1803 | 24% | 31% |
| | | | | |
| *By capacity* | 1144 | 1721 | 23% | 36% |

It is important to consider the impact of increasing interconnection on competition in the SEM. As our forward looking modelling reveals, depending on relative price levels, additional interconnection with GB has a significant impact on the competitive outcome. If GB electricity price levels are consistently higher than SEM levels, this would then limit the ability of the interconnector to constrain market power in the SEM. If prevailing GB price level is higher than the SEM then this effectively means that the additional interconnection increases SEM demand by close to 950MW (and similarly if the SEM price was to be consistently lower than GB, then demand is 950MW less). This has an important impact, in particular in the 2015 scenario, as while investment in additional CCGT capacity by Endesa and Bord Gais means competition among baseload plants will increase, and concentration decline, spare capacity appears to remain concentrated. This is illustrated by higher HHI and market shares when measured by installed capacity compared to when it is measured by output. Since baseload plant are usually less likely to be price setting this suggests that concentration among the price setting plants will be higher than the overall HHI suggests.

This indicates that unless concentration in generation declines through structural changes, intervention through the BCoP and DCs will still be appropriate. The BCoP offers protection against concentration in spare capacity as it restricts the ability of a generator with multiple plant in a merit order sequence to price his cheaper plant up to the cost of his most expensive (knowing that the expensive plant is the plant placing a competitive constraint rather than the cheaper plant, but that the expensive plant is still cheaper than the next competitor). DCs also help in this situation as, despite the BCoP, a generator could still withhold capacity from the market by making the plant unavailable. For a withholding strategy to be profitable, the generator would however need to be able to ensure that the price increases sufficiently such that revenue received by his remaining plant is higher than the loss of revenue from the withheld capacity. Two factors of the SEM protects against this type of behaviour:

- DCs ensure that a proportion of the large generators output is already forward contracted. This means that the generator is not able to increase the revenue received by that capacity by increasing the SMP price through withholding. This reduces the chance of such opportunities arising.
- The revenues received would also need to cover the Capacity Payments foregone by the generator when he withholds the capacity.

Overall, the modelling suggests that the forecast entry and investment in the SEM, and the increase in intermittent generation, is, on the whole, likely to result in increased competition and (absent a market power mitigation strategy) a decreasing ability for generators to exploit market power. It nevertheless also suggests that the intermittency on the system may mean that opportunities to exploit market power may still present themselves in a significant number of cases. This suggests that a robust market power mitigation strategy is likely to continue to have value for the foreseeable future.

### 3.9. Conclusion

In this section, we have noted the particular features of electricity markets that might give rise to market power.

The forward looking modelling of the SEM reveals that the increase in intermittency and interconnection has the potential to have a significant effect on competition in the wholesale market. The analysis further suggests that competition will continue to increase with the commissioning of additional generation. It is however nevertheless the case that the increased level of intermittency may also mean that opportunities for opportunistic behaviour will continue to arise under several potential scenarios. It is therefore likely that there will be an ongoing need for robust market monitoring and bidding principles.

# 4. ASSESSMENT OF THE MARKET POWER MITIGATION MEASURES

## 4.1. Introduction

In this section we evaluate the current market power mitigation measures. The five market power mitigation measures are:

- The BCoP, including monitoring by the Market Monitoring Unit (MMU);
- DCs;
- Ring Fencing;
- The EPO; and
- If necessary, a targeted package of certain local market power mitigation measures.

The last measure was aimed solely at generators that must be operated for local transmission concerns and face no effective competition. These measures could be made effective through the capping of constraint payments or full Reliability Must-Run (RMR) treatment which involves out-of-market contract payments to the generator. As the package was to be applied only 'as necessary', and in practice has not been used to date it is not discussed further in this document.

The first measure applies to all market participants, while the next three measures only apply to ESB and Viridian (who we also refer to as NIEES).

When assessing the market power mitigation strategy for the SEM it is important to consider the measures separately, but also recognise that the RAs intended that they form a coherent overall strategy to mitigate market power. This section discusses the measures separately before drawing together an overall analysis of the market power mitigation measures.

It is important to recognise that during the three years that the SEM has operated, the market power mitigation strategy appears to have helped deliver a generation market which currently appears to attract new entry through investment, alongside new entry in the retail market. It is however the case that there are differences in the level of competition between the retail markets in Northern Ireland and the Republic of Ireland. It is harder to draw conclusions about the relative success of the SEM compared to wholesale markets in other countries, but the high level of reserve margin and transparent wholesale pricing are positive signals. The State of the Nation Review does, however, indicate that the SEM may have higher per unit costs than a number of European wholesale markets, although lower than some others, most likely due to generation mix, back-up fuel requirements, economies of scale and transportation costs.

If competition for peak, mid merit and baseload continues to develop in the SEM, then it would be expected that the need for intervention in the market should decline. Furthermore, the operation of the SEM and the market power mitigation measures provide an opportunity to consider which of the measures have been most effective, and which may have led to unintended negative consequences. Given this, it is appropriate to consider what the overall level of intervention should be in the market given the current levels of market power, and importantly, risks of abuse of market power.

In the subsequent sections we firstly provide a brief overview of the current measures and then discuss the market power mitigation measures in turn.

### 4.2. Design of the current Market Power Mitigation Strategy

The Market Power Mitigation Strategy is outlined in more detail in Section 3 of the SEM Market Power and Liquidity State of the Nation Review (SEM-10-057). Box 4.1 reproduces a high level overview of this document.

*Box 4.1 The Market Power Mitigation Strategy*[14]

| **Components of the Market Power Mitigation Strategy** |
| --- |
| • Bidding principles for generators that reflect an expectation that bids in the energy market should reasonably reflect marginal costs. Thus a Bidding Code of Practice was developed, which are a set of principles upon which participants are required to build Commercial Offer Data (including energy bid prices) for their Generator Units. The principles state that participants must bid their Short-Run Marginal Cost (SRMC) in to the market, and are designed to help mitigate the potential abuse of market power by Generators. |
| • Market monitoring to monitor adherence to the bidding principles by generators and to alert regulators to problems with market rules that may create unintended pricing power or gaming opportunities primarily for generators with large portfolios. Thus the Market Monitoring Unit was created, which, among other activities, involves ex-post monitoring of the operation of the SEM to ensure that generators have submitted bids to the market in line with the Bidding Code of Practice. The Market Monitoring Unit also conducts investigations into the exercise of market power including but not limited to the violations of bidding principles or other market rules. |
| • Directed Contracts (DCs) that incumbent generators with large shares of control over generation in the SEM will be required by the RAs to offer. DCs are essentially financial hedge contracts - Contracts for Differences (CfDs) – which exist outside of the physical electricity market and whose price are based on the projected SMP in the SEM. DCs help ensure that generators with market power do not have an underlying incentive to attempt to abuse their dominant positions in the SEM to the detriment of competitors or consumers (this is explained in more detail later). They also have the benefit of providing forward liquidity to the SEM by helping suppliers, especially those which are not vertically integrated, to manage the risk associated with movements in the SEM's SMP. As they are "directed", it is the RAs who decide upon the methodology, pricing and quantity of these DCs every year. |
| • Ring-fencing arrangements between affiliated generating and supply businesses within the ESB and Viridian groups. The main purpose of these arrangements is to ensure that, via licences, the ESB and Viridian businesses operate independently of each other. They feature separate management, separate accounts, as well as a prohibition of anti-competitive behaviour, cross-subsidies (either to or from their affiliate businesses) and contracts with affiliates other than those which are on an arm's length basis on normal commercial terms. This applies to both the generation and supply arms of the ESB and Viridian groups. As part of the licensing and ring-fencing of ESB and Viridian, the Regulatory Authorities put in place, for ESB Customer Supply (CS) and NIE Supply, an Economic Purchase Obligation (EPO) requiring them to purchase forward contracts in a manner that is economic, fair and transparent. Without an EPO these |

[14] As set out in SEM Market Power and Liquidity State of the Nation Review (SEM-10-057) http://www.allislandproject.org/en/market_decision_documents.aspx?article=dcda0d63-660c-4b28-b71f-9896f306e6cc

suppliers could, where there is market power in the supply market, pay too much for contracts from their affiliates, resulting in their customers paying too much for their electricity and competition in the market being distorted. Note that an EPO was in place for ESB since 1999, but was adapted for the new market structure.

- A targeted package of certain local market power mitigation measures *if necessary* aimed solely at generators that must be operated for local transmission concerns and face no effective competition. These measures would be through the capping of constraint payments or full Reliability Must-Run (RMR) treatment which involves out-of-market contract payments to the generator.

In the following sections we discuss the four main components of the Market Power Mitigation Strategy in turn, comment on their respective performance to date and provide an assessment of whether or not they are likely to remain fit for purpose.

### 4.3. Bidding code of practice, and monitoring by the Market Monitoring Unit

The SEM is a capacity and energy market, such that generators receive revenue separately for making capacity available to the market irrespective of whether any electricity is generated, and for the electricity that is actually generated. In part to avoid the risk of generators being rewarded twice for making capacity available, a BCoP was put in place that required generators to bid at Short Run Marginal Cost (SRMC) in the energy part of the market.[15] The BCoP provides guidelines about how the different elements of SRMC should be made up, including for example, that fuel costs should be calculated on the basis of the opportunity cost of the fuel rather than the price the generator actually paid for the fuel, if for example, it is supplied under a long term contract.

The RAs established the MMU to monitor generators' compliance with the BCoP. The MMU investigates complaints about bidding behaviour and also behaviour that its own analysis may suggest is in breach of the BCoP. Although much of the activity of the MMU is undertaken on a confidential basis we understand that it has investigated a range of concerns about generators bidding behaviour, and some of the investigations have led to concerns being raised by generators or changes/ clarifications to aspects of the BCoP.

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. As we discuss further below this has implications for the demand for contracts to hedge price risk in the SEM.

Overall, without 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. While the MMU has investigated some events during the SEM, the lack of major concerns about bidding behaviour, also suggests that the BCoP substantially limits the ability of market participants to exploit any market power they may have.

[15] In a market such as the SEM that separates remuneration for capacity and energy, it would be expected that in a well functioning competitive market on most occasions generators would bid at SRMC for the energy component of the market.

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. The success of the BCoP and MMU also has implications for other market power mitigation measures, and in particular, it may suggest that the RAs should be careful to ensure that any other measures that are put in place clearly address risks of exploiting spot market power that are not effectively addressed by the BCoP and MMU.

### 4.4. Directed Contracts

DCs require market participants who are considered to have market power in the wholesale market to contract a certain amount of their output by making it available to all market participants.

ESB has made a proposal to the RAs to supplement the directed contracts with a liquidity release mechanism linked to its wholesale market share. Under this approach ESB would no longer be subject to the vertical ring fencing provisions discussed below and the amount of liquidity made available would be partly determined by its market share. We discuss the undertaking proposed by ESB further in Chapter 5. Apart from raising questions of market power, such a change would, absent such a liquidity undertaking, have a considerable impact on market liquidity, and thus needs careful consideration, as does the wider question of whether the contract market is working well.

The RAs determine the volume and pricing approach for the directed contracts based on relatively mechanistic approaches, including the use of the HHI to help determine the volume of contracts in the baseload, mid-merit and peaking segments of the market that are made available. Box 4.2 discusses whether or not an alternative metric may be more suitable to determine the volume of DCs to be offered to the market.

*Box 4.2 DC volumes HHI or alternative metric*

**Would it be appropriate for DC volumes to be based on an alternative metric to HHI?**

Directed Contact complement the Bidding Code of Practice, and other bidding arrangements, in helping to prevent market participants from using market power in the spot market. As the quantities of DCs that market participants are required to provide is determined ex-ante, the mechanism through which these quantities are determined is an important consideration.

The RA evaluated two measures of market power when the DCs where originally put in place; HHI and RSI. The RAs choose to adopt the HHI ahead of the RSI for three main reasons:

- It focuses on high market concentration throughout the price duration curve, while the RSI focuses only on the peak period (price spikes at times of scarcity), and is incapable of detecting potential for the exercise of market power in shoulder and off-peak periods;
- The HHI is a more established and widely used index that has been applied to multiple industries; and,
- The HHI measures competitiveness of an industry while the RSI measures only the power of the largest participant.

Each of these reasons are can be challenged, and could be reconsidered. Specifically;

- The RSI measure can be calculated for any time period, not just peak times. It is also not necessarily correct that peak periods alone are the only times of scarcity. An RSI for baseload, shoulder and peak times is possible and more applicable and informative than

HHI measures over similar periods, due to the electricity market specificity of the measure and the characteristics of electricity markets.

- HHI is a widely used measure in many industries but it is not best suited to electricity markets and can be incapable of detecting market power as it focuses on market shares and not the indispensability of a generator to meeting load.

RSI can be calculated for any market participant, it is not limited to the largest. The measure, by definition, measures the ability of the market, less a participant, to supply the (hourly) load. Based on these objections, it could indeed be preferable to use the RSI to determine the volume of contracts that should be offered.

From the responses to the consultation it is clear that there are concerns amongst some market participants about the effectiveness of directed contracts even where market participants consider that regulation and direction of contracts is appropriate. These concerns are focused on the timing, shape and pricing of directed contracts, although there is an acceptance that the role of the regulator will always be second best i.e. the ideal would be to have an active competitive market for forward contracts. However, most market participants other than ESB argued that some form of regulated mechanism to ensure that liquidity is maintained in the contract market is required. There was a concern that without such a mechanism ESB would have little incentive to contract with third parties, and would instead rely on internal hedging. It is however important to note that these comments are not based on reviewing the ESB liquidity undertaking, which was not available to respondents. Currently ESB is providing the bulk of contracts to the market, including (with the exception of a period in 2009) all the Directed Contracts, as well as around 70% of the non-directed contracts available to the market (if the PSO backed CFDs are included in the calculation this number would be higher still). Figure 4.1 shows the volumes of CFDs offered to the market by incumbents and Figure 4.2 shows the volumes offered by ESB PG alone. In addition to this Figure 4.3 shows the share of contracts offered by the two incumbent generators to the market.

It is also the case that ESBCS and NIEES, owning to their market shares, are currently entitled to take up most of the DCs in the market, and it appears likely that, given that ESB CS is vertically separated from ESB PG, it would also have significant demand for Non-Directed Contracts and PSO-backed CFDs. The overall share of contracts taken up by the Incumbent suppliers is indicated in Figure 4.4.

*Figure 4.1 Volumes of Contracts available in the SEM and Figure 4.2 Volume of contracts offered by ESB (source: State of the Nation paper)*

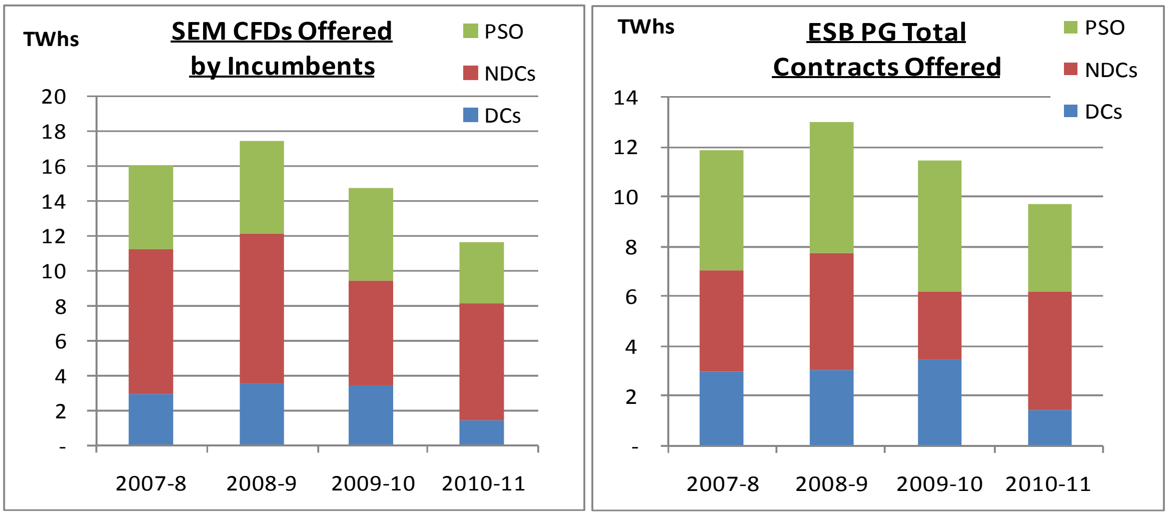
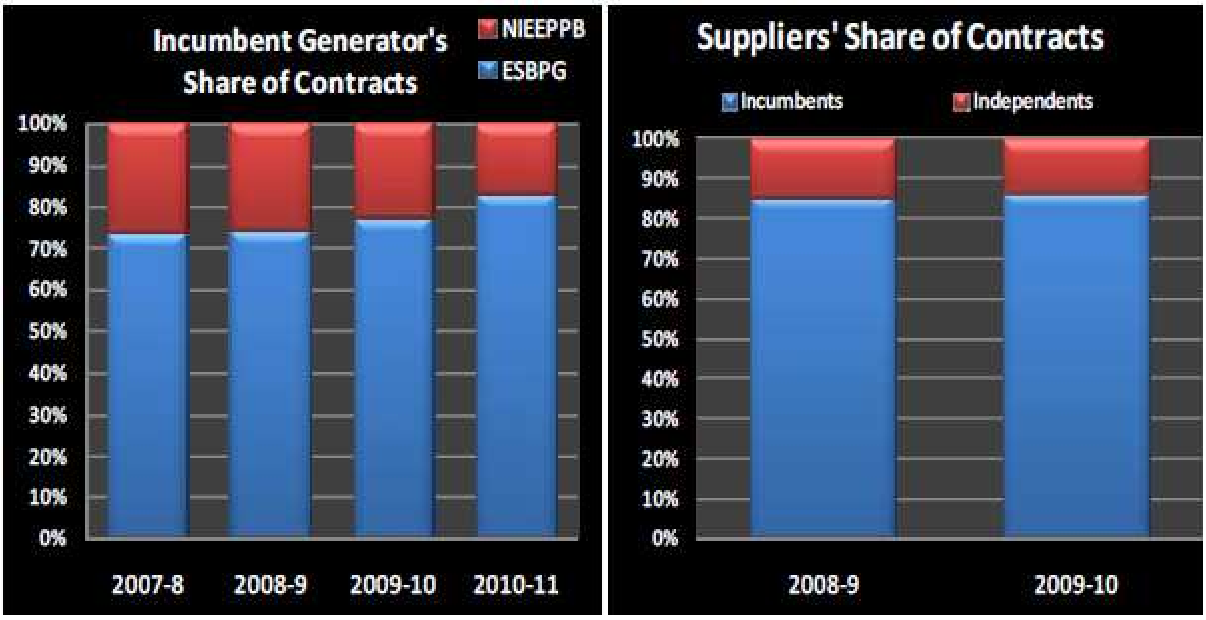



*Figure 4.3 Shares of and Figure 4.4 Volume of contracts offered by incumbents and taken up by incumbents and independents suppliers (source: State of the Nation paper)*




There is an important question about the demand for hedging contracts against SEM prices. A key determinant of changes in SEM prices is fuel costs, and most of the main fuel costs used by generation plant within the SEM can be hedged in primary commodity markets that are relatively very liquid, including gas and coal markets. Therefore, market participants can in theory achieve a substantial hedge against a key price risk in the SEM without using SEM related contracts, although this hedge will be less than perfect i.e. participants will still be exposed to some SEM price risk. As the correlation between the SMP and fuel prices becomes less good with an increase in wind, the option of hedging in fuel markets will become less attractive.

However, it is important to note that fuel cost hedges are an imperfect hedge against the risks associated with the SEM, and hence suppliers are likely to want to hedge the SEM price through SEM forward contracts. Other risks associated with SEM prices include the level of demand, and therefore, how far up the merit order dispatch is required. Although the SEM is a relatively mature market, so the merit order should be relatively well understood by most market participants, as the extent of wind penetration increases, so the accuracy of any prediction of the shadow price will likely decrease. So most participants who require revenue/ cost certainty will require CfDs.

Nevertheless, it is important to note that there are reasons why a relatively low level of contract market liquidity in the SEM might be expected (these reasons are set out in section 5 of this document). A number of respondents to the information paper suggested that a much more liquid contract, especially for shorter term offerings, was required.

Overall we recognise that DCs provide an important source of hedging and liquidity release mechanism and absent them, some third parties may find it difficult to access electricity hedging contracts, and that the risks of market power being exercised would increase due to the potential reduction in contracted capacity by generation. While we discuss liquidity further in Chapter 5, it is important to note that the scale and timing of changes to DCs should be carefully considered so that it does not attempt to require companies to make available far more output than would be expected to be required for reasonable risk management activities in the SEM. It is also important to ensure that the requirements are place on market participants in a fair and proportional way, recognising not only the special responsibility incumbent on a market participant with market power in a market, but also that a liquid contract market is of interest to all market participants in the SEM.

## 4.5. Ring Fencing

The ring fencing provisions can be described as having two main parts. Horizontal ring fencing prevents the generation and supply businesses of ESB and NIEES (see the State of the Nation Review for details) from sharing information and working together between units at the same level of the supply chain. For example, different generation businesses within the ESB group are ring fenced separately from each other. Vertical ring fencing prevents ESB and NIEES from sharing information and working together between their retail and generation businesses. These two types of ring fencing seek to address different aspects of the potential abuse of market power. Horizontal ring fencing seeks to address only market power at the level of the supply chain to which it applies, e.g. separating generation business units. Vertical ring fencing seeks to address the concern that a vertically integrated company may be able to exploit market power across the supply chain, and particularly in the domestic retail market, which evidence from GB suggests remains an issue even in a larger market with six large competitors. We discuss each of the types of ring fencing in turn.

Given the discussion above about the effectiveness of the BCoP and MMU, we are sceptical about whether horizontal ring fencing provides significant additional protection against the exploitation of market power whilst the BCoP remains in place. Furthermore, ESB has stated that ring fencing imposes material costs on its businesses, although it is unclear whether this is a commonly held view. Overall, given that operational horizontal ring fencing does not seem to materially increase the protection against the exploitation of market power given the presence of the BCoP and MMU, but can impose costs, its continued role should as a minimum be carefully considered. It may be premature to horizontally merge the companies, as maintaining legal separation has option value, but this in itself would not be an argument against information exchange and possibly economising on associated costs by sharing trading activities.

The main effect of vertical ring fencing, alongside the EPO/NDO, is to prevent ESB CS and NIEES from having a natural hedge[16] against the risks associated with the costs for supplying their customers – this natural hedge occurs when, simplistically assuming that a supply co is 100% self-supplied, the generating companies and supply companies are viewed at the group level – any loss/ gain on retail contracts arising from movements in wholesale prices will be offset by equal and opposite gain/ loss on generating profits and vice versa. Instead they can at best seek to hedge the risk through CfDs or direct hedges of fuel costs, or if their parent companies chose so to do they can deal with risk at the group level, through the natural hedge. As ESB has noted, many retailers in gas and electricity markets in other countries (with relatively competitive markets) use natural hedges to a significant degree, which suggests that such an approach is an efficient way of managing risk, notwithstanding that it is difficult to draw conclusions about the SEM from other markets with different structures. This means it is important to consider whether the vertical ring fencing is significantly reducing the risk of market power being exploited given other measures such as the BCoP and MMU, and furthermore, whether it is the best way to reduce the risk of market power being further exploited if additional measures are required. As discussed above for DCs, we recognise that there may be a residual issue regarding a lack of liquidity in the contract market, which vertical ring fencing could in principle help address because it encourages ESB PG to make CfD's available and encourages ESB CS to purchase them, more so than if they could rely on a natural hedge. However, vertical ring fencing imposes some costs on the companies to implement e.g. through the need to duplicate trading and finance functions, which may mean that revised arrangements for directed contracts or alternative liquidity release provisions should be considered as potentially cost effective ways to address a lack of liquidity in the contract market given the presence of market power.

Overall, we consider that the benefits of operational horizontal ring fencing seem unlikely to outweigh the costs of implementing the ring fencing given that it is unclear what additional protection such ring fencing provides against the exploitation of market power, over and above the protection provided by the BCoP and MMU.

Vertical ring fencing could in principle help address the concern about a lack of liquidity in the contract market due to the presence of market power. More importantly though, vertical ring-fencing, incentivises ESB to innovate in providing contract market liquidity and to purchase in the most cost effective manner from a range of generators. If this benefit is passed on to consumers, it may more than offset any operational costs imposed by vertical ring-fencing.

### 4.6. Economic purchasing obligation

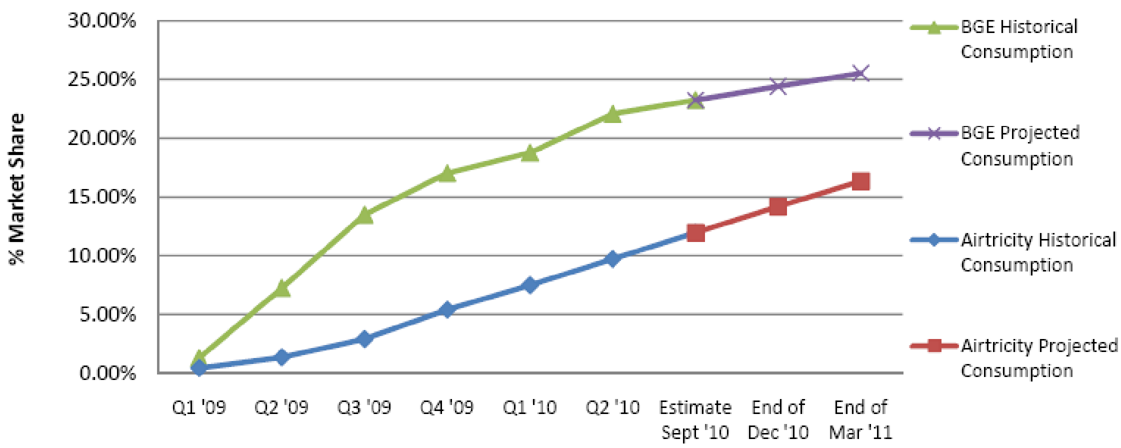
This obligation is placed on ESB CS and NIEES to seek to ensure that they do not procure electricity ineffectively and pass on inefficient costs to their customers, which would lead to these paying more for wholesale electricity than is appropriate, although it clearly has an impact on the generation market as it only allows suppliers subject to the EPO to buy economically priced power. It allows the RAs to review *ex post* the purchasing and hedging decisions of the

[16] By a natural hedge we mean the ownership or control through contracts, of generation capacity that matches a material proportion of the demand requirements of customers.

companies to ensure that they were efficient and offered value for money[17]. The provisions are intended to recognise that the companies can only make decisions based on the information available at the time and the RAs should not use hindsight to evaluate the decisions. To help with compliance with the provisions the companies develop procurement principles within which their decisions are taken.

It is important to recognise that this provision has implication for both retail and wholesale market power. A company could comply with the EPO for its retail customers while still exploiting market power in the wholesale market to raise wholesale electricity costs for all customers. Therefore, the provisions are only likely to remain appropriate while there is a concern that the companies have a level of market power in the retail electricity market that would allow them to pass through higher than efficient wholesale electricity costs. The introduction of retail competition in RoI is eroding any potential benefit from inefficient purchasing, although the position in the domestic market is very different in Northern Ireland (although the EPO was removed for the more competitive industrial and commercial market in Northern Ireland in 2009). Figure 4.5 illustrates the rapid gain of consumers by independent suppliers in the RoI. The most recent quarterly Retail Market Competition Review[18]further found that the average annual switching rate over the previous 12 months was 22.

*Figure 4.5 Gain of domestic retail market share by BGE and Airtricity[19]*




Further to the Roadmap consultation, the EPO has been removed from ESB CS for industrial and commercial, coincident with the cessation of retail price regulation from the 1st October, and CER intends that it will be removed for ESB CS domestic customers once the criteria are met for this market, subject to any replacement mechanism which the SEM Committee may deem necessary. In this context, we note that the 3rd Package places requirements on regulators to monitor the market to ensure that customers are benefiting from competition, and to take action where that is not the case.

*Figure 4.6 Spot prices and fuel costs*

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[17] We understand that to date, the CER has assessed compliance by engaging independent consultants to audit ESB CS as the PES supplier.

[18] Retail Market Competition Review Q2 2010 CER/10/116: http://www.cer.ie/GetAttachment.aspx?id=76226042-e3de-4028-8f64-92794db01d48

[19] Source: Figure 2.4, page 9 of Retail Market Competition Review Q3 2010 CER/10/196

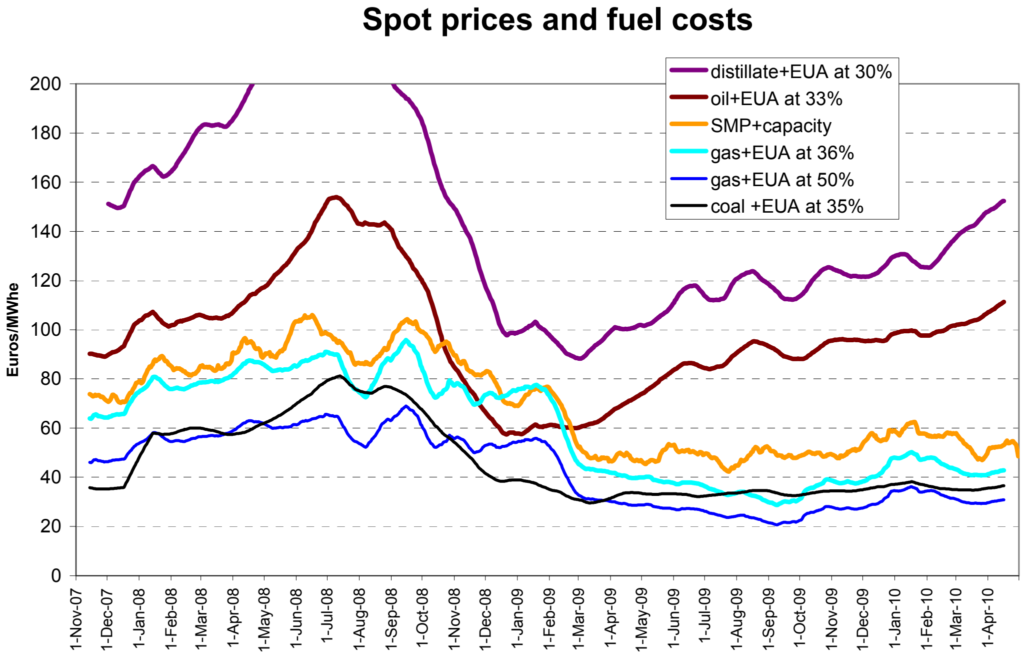



Figure 4.6 shows that in the latter part of 2008 clean[20] oil and coal prices collapsed, and in early 2009 so did clean gas prices. Incumbents who had hedged their fuel costs forward to reduce the risk of offering fixed price electricity contracts suddenly found that the spot fuel costs and SMP in the SEM had sharply fallen, allowing entrants to offer discounts on ESB CS's offerings (typically 10%) as they could contract at now considerably lower prices. So some caution is required in drawing conclusions about the future path of retail competition and market shares from this single event, and while the value of the EPO may be reduced where part of the market for which the company is purchasing wholesale electricity is vigorously competitive (because it will in practice be difficult for the company to purchase some electricity efficiently and other electricity inefficiently) one must be cautious in assuming that retail market competition will continue to deepen.

There is also a practical question as to whether an EPO can be effectively enforced. It is likely to be difficult for a regulator to determine that all but the most obviously inefficient decisions by a company breach the obligation. In other words, companies are likely to have a reasonable margin of error within which to make slightly inefficient decisions before any action is taken. This is because it is very difficult for a regulator to reasonably question decisions that a company makes even if in hindsight they turn out to have been more costly than other available decisions.

### 4.7. Wider observations on the domestic retail market

In this sub-section we briefly discuss the domestic retail market in the Republic of Ireland and the imminent full removal of the EPO, the potential concerns arising from the high market shares of the ESB group, and the potential need for regulatory intervention.

[20] When hedging electricity prices, it is the fuel cost that matters, and this includes the EUAs necessary to burn the fuel in the relevant power station. The clean fuel costs include the cost of EUAs as well, which can also be hedged.

The Roadmap set out the CER's phased approach to deregulation of the Irish retail electricity market. It noted a number of criteria that would need to be met in order for ESB to be de-regulated, including:

- There are at least three suppliers active in the relevant market.
- There is a minimum of 2 independent suppliers, each of which has at least 10% share of load (GWh) in the relevant market.
- ESB PS and ESBIE combined serves or will serve within a specified period a defined percentage of consumption market share in a relevant market. For each of the Business markets, the percentage market share is 50% or less. In the Domestic market, the percentage share is 60% or less.

Additional criteria for the Domestic market were set out as (i) switching rates greater than 10% and (ii) a commitment, satisfactory to CER, for the rebranding of ESB supply companies prior to the deregulation of the domestic market.

The Roadmap also noted that, given the unidirectional constraint between jurisdictions (arising from limitations in switching systems in Northern Ireland), the Irish market and the Northern Irish market should be considered separately, but that this will be reviewed upon completion of the Harmonisation Project in 2012.

The Roadmap also considered the EPO and the CER has decided that effective competition and commercial pressures render the EPO unnecessary and inappropriate and that therefore, subject to the Roadmap criteria for a competitive market being met, CER has removed the price control from ESP PES and the obligation of the EPO for business customers from 1st October 2010 and will do so for domestic customers when the criteria has been met. The removal of EPO on either PES is subject to replacement by any new conditions that which the SEMC may deem necessary to address wholesale market power or liquidity issues.

Domestic customers have respond to clearly announced offers by new entrants undercutting incumbents. But as noted above, the conditions that led to this may not be repeated, and the evidence from domestic liberalization in GB was that many of the new suppliers entering rapidly exited, and they now have less than 1% of the market, and concerns remain that six largely vertically integrated incumbents appear capable of sustaining prices above competitive levels, although no actual evidence of this has been found. Given that the GB market is more stable and mature, this raises concerns as to how retail competition will continue to evolve in the SEM, and whether some further measures will be appropriate as and when the EPO is removed and if vertical ring-fencing was permitted, given the market shares of the incumbent. Such measures might include a price cap on the margin of the supply business, but at this stage we simply wish to flag the importance of addressing concerns about retail market power, and the risks of implementing (the reversal of) structural decisions that were designed to make the retail market more competitive.

### 4.8. ESB's proposal to re-integrate

In this section we briefly discuss ESB's proposal to re-integrate. The proposal submitted by ESB is summarised in Box 4.3.

*Box 4.3 ESB's proposal to re-integrate*

| **Summary of ESBs proposal** |
|---|
| ESB's retail market share has fallen from almost 100% of the Republic of Ireland (ROI) market in 2000 to 52.5% in 2010. In addition, its wholesale market share has fallen from over 90% of the ROI market in 2000 to 45.1% of the Single Energy Market (SEM), and ESB predicts it will fall below 40% in the next two years.<br><br>Due to these changes and the competition and market arrangements in the Irish electricity market, ESB believes that if it were deregulated from a retail price perspective, the market structure would prevent it from exercising market power in the wholesale market, and it would remain unable to profitably follow the strategies that the regulations are designed to prevent.<br><br>ESB believe that de-regulation will bring four key benefits to the Irish energy market:<br><br>**1) De-regulation will reduce the duplication of unnecessary activities to the benefit of consumers.**<br>**2) De-regulation will allow ESB to manage the risk associated with a stand-alone supply business.**<br>**3) De-regulation will avoid potential distortions and instabilities in the retail market that are contrary to the interests of consumers.**<br>**4) De-regulation will avoid the likelihood of discriminating unfairly and will avoid regulating where it is obsolete or unnecessary.**<br>As such, ESB developed six key proposals that it believes would improve the current regulatory environment. These are summarized below.<br>1) The Regulatory Authorities (RAs) should immediately approve arrangements permitting the disclosure of commercially sensitive information between CS and Power Generation (PG), and the use of this information by both businesses. This will allow PG to hedge the risks to which CS is exposed, and allow CS to develop products that account for such risk.<br>2) The RAs should immediately modify the licences granted to the independent generators within the ESB group, removing all conditions requiring these to be separated.<br>3) Directly following retail de-regulation, the RAs ought to remove all conditions requiring the separation of CS and ESB Independent Energy (ESBIE) and remove the condition in the ESBIE licence preventing it offering supply to customers with consumption lower than 225MWh. This would allow ESB to remove some duplication of operations, and it argues this would also bring benefits to industrial and commercial customers.<br>4) As of January 2011, the CS and PG licences should be modified to remove all conditions requiring vertical separation between those businesses.<br>5) As of January 2011, the PG licence and the licences for all of ESB's independent generation businesses should be modified to remove all conditions requiring their horizontal separation.<br>6) Following the commissioning of the East-West connector between ROI and GB (expected to be completed in 2012) there should be a review and consultation process with the aim of phasing out Directed Contracts, as by this stage the market will be large enough that additional measures restricting market power will be unnecessary.<br><br>ESB foresees that if these proposals were expected, they would protect the interests of consumers, promote competition, ensure that the licensee can finance activities, and promote efficiency and economy.<br><br>The submission by ESB was complimented by a proposed liquidity undertaking to the SEM committee. This is summarised in Box 5.2 and the full reintegration and liquidity proposals are attached as Annex 5 to this consultation. |

We discuss the ESB proposals further alongside our policy options in Section 6.

### 4.9. Conclusions on market power mitigation measures

Developments since the introduction of the SEM suggest that it may be appropriate to consider relatively material changes to the market power mitigation measures. In particular, we have reached the following preliminary conclusions:

- The BCoP and MMU provide substantial protection against the abuse of market power. Nevertheless feedback from market participants have identified that the monitoring activities could be more transparent.
- There appears to be a residual and reasonable concern about a lack of liquidity in the contract market, notwithstanding that we would not expect the SEM to be characterised by very high levels of contract market liquidity. There are some concerns from market participants about the operation of the DCs that, if addressed, should in principle help address these issues, although it should be borne in mind that DCs are first and foremost a market power mitigation tool, rather than a liquidity release mechanism.
- It is unclear what additional risks of exploitation of market power operational horizontal ring fencing would address, that are not already addressed whilst the BCOP remains in place. Given the costs of such ring fencing provisions it may be appropriate to amend them to allow operational horizontal integration. Operational information exchange and sharing of a common trading platform might deliver all the benefits of removing the horizontal restraints without the need for full legal integration.
- Vertical ring fencing is an important component of measures to restrain market power in the domestic retail market, which evidence from GB suggests is more prone to the exercise of market power than comparably concentrated markets for other goods and services. Indeed, Ofgem now requires separate accounts between the retail and power generation arms of the big six integrated GB companies. Given the salience of the retail market, great care should be exercised before taking structural decisions that might increase costs for customers through reduced incentives for efficient purchasing and contracting.

Vertical ring fencing, together with the Non Discrimination Obligation, can in principle help address the lack of liquidity in the contract market by encouraging contract provision, but revised directed contracts or an alternative liquidity release mechanism may also be appropriate mechanisms to address this issue. We would welcome market participants and other stakeholders' views on these initial conclusions.

# 5. CONTRACT LIQUIDITY IN THE SEM

## 5.1. Introduction

In this section we examine the current level of contract liquidity in the SEM, as well as outlook for liquidity and access to hedges. The section starts off by providing a brief overview of liquidity as a concept, including why it is a desirable feature of a traded energy market. It then discusses the current levels of contract liquidity in the SEM and what is currently driving it and provides some international examples. It should be noted that the starting point for a discussion of liquidity in the SEM is slightly different from similar debates in for example GB. This is because the gross mandatory pool market system of the SEM means that price formation in the spot pool market is based on nearly 100% of capacity.

## 5.2. Contract liquidity as a concept

In this section we briefly discuss why contract liquidity is, firstly, needed and, secondly, a desirable feature of a competitive energy market structure.

Liquidity is, alongside effective access to networks and price signals on a spot market, an important and desirable feature of competitive markets. When present, contract liquidity enables non-vertically integrated parties to effectively source energy and manage risk. This lowers barrier to entry in both upstream and downstream electricity markets. Absent contract liquidity:

- A supplier is exposed to the SMP price, as well as uncertainty about its consumers' demand. This limits the ability to offer fixed price contracts, and will also increase the risk to the supplier's cashflow and profitability, unless it can pass on the variability in input prices to his consumers, or hedge through fuel proxy hedges.
- A generator is also exposed to the SMP and less able to reduce risk by "locking in" gross revenues. In the SEM, the risk to a generator is arguably lower than in self dispatch systems (such as BETTA), as the generator will be dispatched and receive the SMP and Capacity Payment if it is in merit, and the Capacity Payment if it is not in merit, but still available. This is not to say that market participants seeking to invest in a new project would not be aided or need forward price certainty through forward contracts or tolling agreements to help bank their projects. Furthermore, shareholders often value predictability of gross revenue.

Absent contract liquidity, a rational actor may seek to hedge through vertical integration[21]. This is driven by a desire to lock in gross margin by securing fuel hedges matching the duration of its consumer contracts. It is however unlikely to take a fully hedged position in order to protect himself against the risk of being too long, which could for example come about through customer turnover, or being out of the market.

[21] Note that market participants may still wish to hedge their exposure through vertical integration even if they have access to a liquid wholesale market.

As identified in the detailed document published by Ofgem[22], contract liquidity provides a range of benefits as it can:

- facilitate new entry in generation and supply by allowing new entrants to buy and sell electricity to match their output and customer base with confidence;
- reduce the ability of market participants to engage in market manipulation;
- lead to a wider range of products and counterparties for participants to hedge their risk exposure;
- increase confidence in traded prices;
- allow non-vertically integrated entrants to participate on the same terms as vertically integrated incumbent firms by enabling them to effectively hedge their position;
- allow parties to better manage long-term risk and provide long term price signals about future market development, which inform investment decisions and promote long term security of supply; and
- allow market participants to fine tune their positions without extensive costs.

The nature of the SEM as a gross mandatory pool means that by definition the physical spot price is set by reference to the total market volume (in other words the spot market churn is 100%). This means that the confidence in the spot price will be high, as all available supply and demand factors will be reflected in the resulting price. To a certain extent this differs from the liquidity discussion currently ongoing in the GB BETTA market, where typically the exchanged based spot market churn has been much lower at around 3-5%. Confidence in the spot market price formation is important, as financial contracts need a fair benchmark to be settled against. It is further worth noting that if there is significant vertical integration in a market, and in the absence of bidding rules, the spot price may become less relevant as a transparency tool as it may not reflect the value vertically integrated players put on the power.

In the subsequent sections we focus on the development of contract market liquidity; in other word contracts for power with a longer time horizon than the immediate day-ahead prompt market, which has transparent price formation due to the mandatory nature of the SEM.

### 5.3. Key features of liquidity and measures

Before we investigate liquidity in the SEM and its drivers it is useful to establish the key functions and concept of liquidity. A first important distinction to make is between effective access of market participants to hedging contracts and regular trading:

1. The ability of suppliers to obtain hedging contracts at a reasonable cost: this is the critical concern for electricity suppliers as it enables them to offer desirable fixed price contracts to their consumers.

[22] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Liquidity%20Proposals%20for%20the%20GB%20wholesale%20electricity%20market.pdf

2. Whether or not the contracts are regularly traded, and there is sufficient volume for trades to be executed with a reasonably small impact on the prices[23]. This aspect is important as it both provides on-going price signals and confidence in the price formation in the market, but it also importantly reduces the risk of suppliers taking up longer term hedging contracts as it enables them to moderate their positions.

In the context of the SEM as an evolving electricity market it is important to consider both of these aspects of the market. In order to safeguard the competition already achieved in the RoI retail markets, and facilitate the development of competition in NI the ability to obtain hedging contracts is important. As we note elsewhere it is possible to undertake a degree of hedging using fuel contracts, but for smaller suppliers access to suitable product is important. In order for the SEM to continue to evolve and deliver benefits to Irish consumers it is however also desirable for the second aspect to emerge.

### 5.3.1. Measures of liquidity

Before considering the drivers of liquidity and experience to date it is useful to first briefly consider the potential measures of liquidity available. There are multiple possible definitions of contract liquidity, and also several ways to measure it. Common measures include:

- **The Churn Rate:** churn is simply the total volume of trade divided by the physical demand of a market. Commonly it is calculated on an annual basis as:
    - total annual volume traded/total annual electricity demand
    - In other words a churn rate of "2" would imply that every MWh of electricity consumed in a market will have changed hands twice.
- **Number and distribution of trades:** this measure studies how frequently a particular product is traded, and how trading occurs over the duration of contracts;
- **Products available:** are the products available suitable to the needs of market participants. For example the product size may not be suitable for suppliers of minor quantities;
- **Bid-offer spread:** in a liquid market the spread between bids and offers on the markets will be reduced, reflecting the lower transaction cost involved;
- **Forward contracts:** this measures how trading develops along the various durations of products. For example how does the frequency and volume of trading on a contact 12 months from delivery compare to one 5 months from delivery?
- **Number of active market participants:** this final measure can provide an indication of how attractive potential market participants consider the market to be.

These measures provide reasonably simple metrics of the overall liquidity of the market. Measures such as the churn ratio, the number of trades and the number of market participants furthermore allow for simple comparisons of liquidity between markets.

[23] One aspect of contract liquidity is the ability of the market to absorb transactions without the market price moving significantly as a result.

It is however important to note that all of these measures only provide a higher-level picture of liquidity, but do not individually provide a complete picture of how liquid the market is. As discussed earlier contract liquidity is not an end in itself, but is a likely feature of an effective market. In light of this it is important to complement the study of the higher-level indicators with consultation with market participants.

### 5.4. Current state of contract liquidity in the SEM

In the State of the Nation Review, the RAs provides a presentation of the available data on the current state of hedging and liquidity in the SEM. The electricity hedging available is focused to three types of products; Directed Contracts, Non-Directed Contracts and PSO-Levy backed Contracts for Difference. We now discuss the data available for each of these.

#### 5.4.1. Directed Contracts

The Directed Contracts are not market liquidity instruments as such, but rather instruments provided as a product of the Market Power Mitigation Strategy. The contracts are “Directed” for several reasons:

The *type and quantity* of contracts offered are determined by the RAs. As discussed in Section 4, the types and quantities are determined with reference to the HHI index for the forthcoming period. It is an iterative calculation. In each iteration, the largest party is required to offer additional contacts, until the predicted HHI index reaches a pre-determined level.

The *Price* of the Directed contracts is determined by the regulatory authorities by calculating what the cost of the products would be given the current valued of underlying fuel and CO2 products.

The *eligibility* for suppliers to take up the Directed Contracts is based on the supplier’s consumer portfolio, and the supplier can choose take up the directed contracts within certain contracting windows. Contracts not taken up by an eligible supplier are then re-offered to remaining suppliers.

It is important to note from the outset that these characteristics of the Directed Contracts mean that they are not market hedges in a conventional sense (i.e. voluntary contracts entered into by parties to mitigate risk). They do however provide a degree of hedging to suppliers based on their current share in the downstream market.

*Figure 5.1 Directed Contracts Volumes (source: data from RAs)*

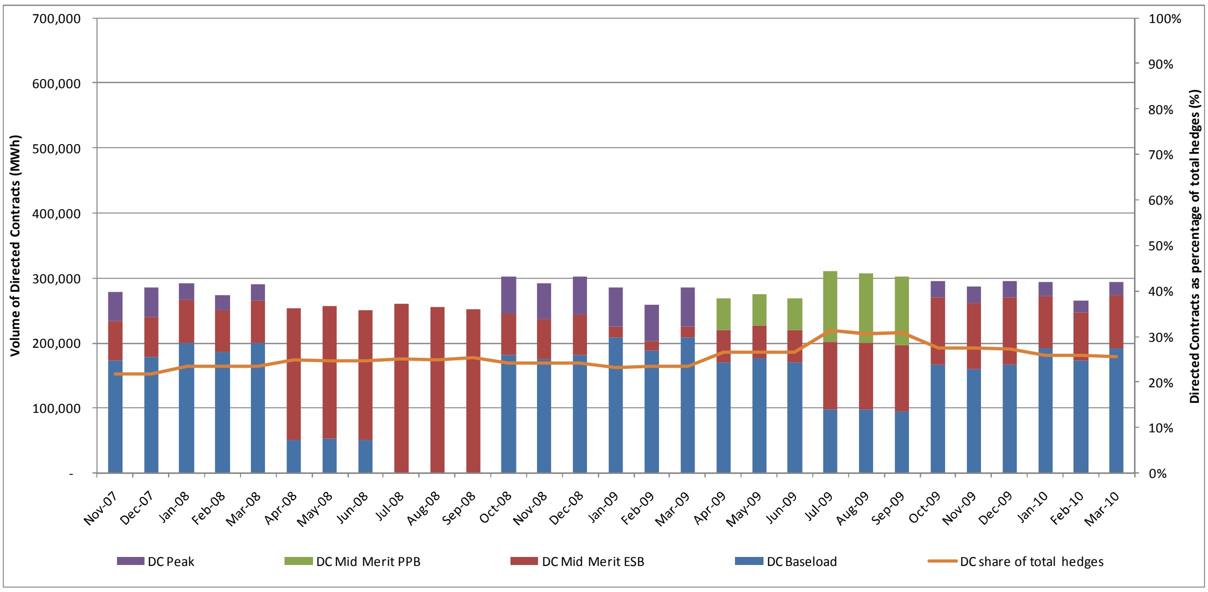



Figure 5.1 illustrates how the volume of energy covered by DCs has evolved since the start of the SEM. Note that whilst the chart shows variations on a monthly basis, the volumes of DCs were in practice determined on a quarterly basis over the period. Any month on month within-quarter variation is due to differences in the number of days of the months. As explained elsewhere the quantity of contracts available is linked to a measure of market power in the SEM, and hence if the measure of market power increases then the total volume of DCs would increase.

Due to the nature of DCs it is not likely that there would be any re-trading of these products unless a better priced contract becomes available. Since DCs are provided to the market on eligibility in proportion to their current market share, they effectively reduce the need for further hedges without effecting the relative positions of current market participants. Thus by selling its DCs a participant would increase his market exposure relative to his competitors. Since the alternative hedges offered through the Non Directed Contracts and PSO levy backed CfDs tend to trade a premium to the DCs the party would then be worse off. It would not be impossible for a vertically integrated, or over-contracted player to offer a NDC type product backed by the volume obtained through the DC thereby exploiting any premium between DC and NDC prices. In practice however there are currently only seven parties likely to be recipients of DC volumes.

A further issue worth mentioning again is that marker power metrics such as HHIs and market shares are only valid in the context of a particular relevant market[24]. With interconnection with GB it is possible that the relevant wholesale electricity market may also see a significant increase in competitive constraints from the GB market. If the market definition was to change then the HHI measure, which the Directed Contracts is based on would diminish significantly, while a degree of market power, as indicated by the RSI analysis may remain. While we do not consider it possible this point to determine under what conditions market integration between the SEM and GB would be sufficient for the market definition to be expanded, this could have an effect on the DCs, both as a market power metric, and provider of a degree of hedges to the market.

### 5.4.2. Non-Directed Contracts

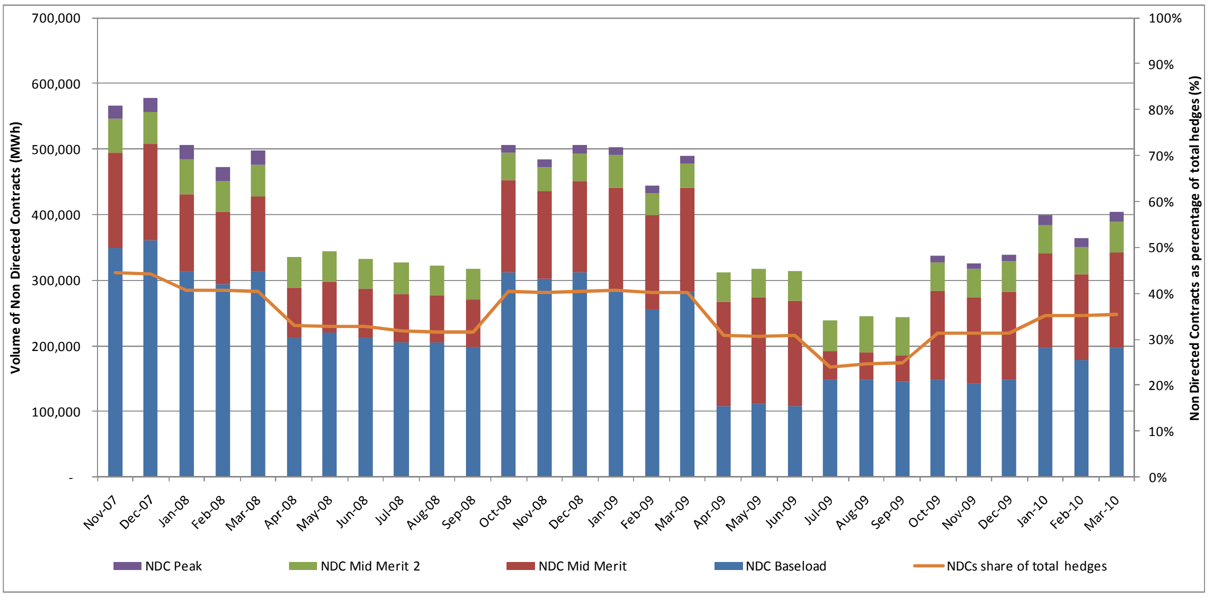
[24] The RSI does not rely on the definition of a relevant market and remains applicable.

Non-Directed Contracts are market instruments offered by parties[25] in the SEM on a voluntary basis. Non-Directed Contracts have the following properties.

- The *type and quantity* of Non-Directed Contracts offered are determined by the offering parties;
- The *Price* of the Non-Directed Contracts is determined through auctions, subject to reservation prices set by the offering party; and
- The *eligibility* is not restricted[26] and any interested party can bid for contracts.

The price and quantity of Non-Directed Contracts are determined by market dynamics. Figure 5.2 shows how Non-Directed Contract volumes available for particular period have evolved over time.

*Figure 5.2 Non - Directed Contracts volumes (source: data from RAs)*




### 5.4.3. Republic of Ireland PSO Levy Associated Contracts For Difference

The PSO Levy backed Contracts for Difference are a special type of product offered by the market on the basis of mainly peat stations. The PSO backed CfDs have the following properties:

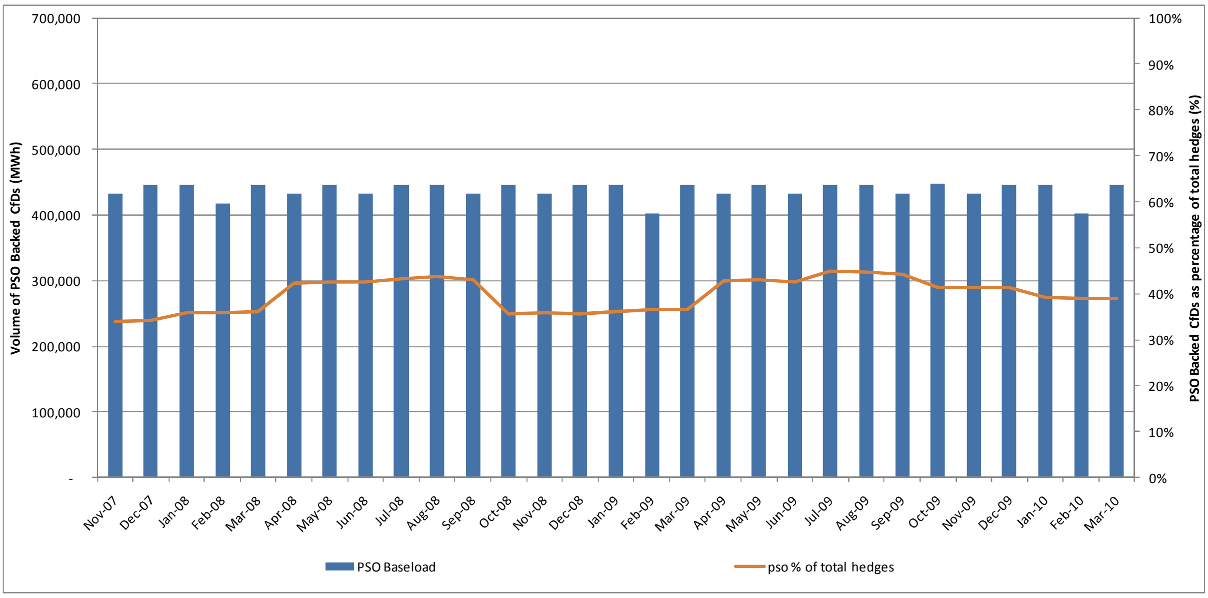
- The *type and quantity* of the CfDs are determined by the Regulatory Authorities based on the output of the backed plants;
- The *Price* of the PSO levy backed CfDs is determined through auctions, subject to reservation prices set by the CER; and
- *Eligibility* is not restricted and hence any interested party can bid for contracts.

The price of the PSO backed CfDs are therefore determined by market dynamics.

[25] For the purpose of our discussion here the PPB PSO contracts are included as part of the NDCs.

[26] Eligibility is however subject to credit cover requirements and costs associated with legal review of contract documents. It is also worth noting that there are de-minimis quantities.

*Figure 5.3 PSO Backed CfD Contracts Volumes (source: data from RAs)*




## 5.5. Drivers of liquidity

In this section we discuss the drivers of contract liquidity in the SEM to date. From the outset we consider it is important when considering the prospects for liquidity in the SEM to consider three important features of the market.

- Firstly the SEM is still a relatively young market, having only been in operation for three years.
- Secondly products offered in the SEM to date have had a relatively long duration (quarters, years), and in many cases started a period out into the future. Given the lack of products with shorter duration closer to delivery, it is difficult for parties to moderate their hedging positions closer to delivery. This increases the risk of entering into contracting positions. It should be noted that monthly products have recently been made available and that products are being made available on a more regular basis. This serves to reduce the risk of parties entering into contracts by making the contracts price less risky. Absent secondary trading it is however still difficult for parties to moderate their positions once they have been entered into.
- Thirdly the SEM is a relatively small market which may mean that it possible that the market simply is not large enough to attract generic trading. By way of comparison, it was only when NordPool was expanded from Norway to also cover Sweden, Denmark and Finland in the period of 1996-2000 that financial trading started occurring at a large scale.

These factors present natural reasons why, firstly, financial trading has not emerged to a greater extent in the SEM, and secondly also highlight that this may not actually mean that there is a fundamental flaw with the SEM that may need to be addressed.

As in most liberalised electricity markets based on thermal generation[27], a vertically integrated participant in the market (generation and supply) could potentially offer a range of different products to its end users based on underlying fuel contracts. For example the vertically integrated player could:

- Offer a longer term fixed price product, which would then be underpinned by the fuel hedges (such as gas and coal) required by its generating portfolio over the same timescale;
- Offer shorter duration products, such as products based on monthly prices; and/ or
- Offer ex-post tracker products, based on the actual settlement price of the fuel contract, rather than forward products.

A vertically integrated supplier would also have a natural hedge against variability in the efficiency of the plant type, which it would be less able to hedge against using a fuel hedge. This could provide the vertically integrated supplier with additional flexibility to develop innovative products relative to a stand-alone supplier[28].

In the subsequent sections we examine the incentives on stand-alone generators to offer hedges and for stand-alone suppliers to take these up.

### 5.5.1. Incentive for generators to supply hedging contracts

In this section we discuss the incentives on generators to offer hedging contracts to the market.

In many electricity markets, generators will generally seek to offer forward contracts (or tolling agreements). This is because an independent generator will wish to contract forward to ensure forwards utilisation and revenue of its plant. The generator will effectively seek to "lock in" a gross margin based on an agreement to sell its output, and also contract for its fuel price over a similar timescale. Such behaviour will help secure gross revenue for the generator. Contract market liquidity is therefore a key consideration for an independent generator as it enables it to manage the risk profile of his investment. Absent an ability to contract forward the independent generator will need to rely on the potentially more volatile shorter term market for revenue.

A generator with a vertically integrated supply business is subject to a slightly different set of incentives compared to the independent generator. A vertically integrated party can manage the overall risk to his business by offering fixed price contracts to his end users, and then locking in a gross margin by signing a forward agreement for his input fuel. This means that overall the vertically integrated business is less dependent on the effective operation of the contracting market.

The SEM have some features which mean that there are deviations from these principles outlined above. In particular three factors will influence the incentive for independent suppliers to offer hedging contracts:

[27] It is different in hydro dominated systems. In hydro dominated system the forward cost of electricity often reflects the underlying hydro reservoirs, rather than underlying fuel contracts.

[28] This is based on the important assumption that a stand-alone supplier would only be able to enter into underlying fuel hedges, not power market hedges.

- Firstly, at least a significant proportion of the generator's fixed costs are covered by the capacity payments.
- Secondly, even in the absence of contract liquidity, a generator has certainty regarding dispatch as long as he is in merit.
- Thirdly, the gross mandatory pool system means that the generators are guaranteed dispatch as long as he is in merit. The central dispatch system also means that a forward contracted generator becomes subject to the risk of not being dispatched.

Taken together these factors mean that an independent generator in the SEM is likely to be subject to less risk than a similar company in say the GB BETTA market. Given this, it appears likely that there will have been less of an incentive on generators to drive the development of liquidity to date.

### 5.5.2. Demand for hedges by suppliers

In this section we examine the risks faced by a stand-alone supplier in the SEM. The section assumes that the only hedging available to the supplier is through underlying fuel contracts, and does not consider the possibility that the supplier would be able to cover part of its load from Directed Contracts.

Stand-alone generators are partially hedged through the link of SRMC to the SMP, although the analysis above suggests that the hedge is incomplete, as a different fuel than that of the generator may fuel the price-setting plant. Stand-alone suppliers are more exposed as in the absence of electricity hedging contracts they are exposed to the risk that the efficiency of the price setting plant, or the fuel type and price is different from their expectation. An interesting question is how the variability of prices may develop. Three effects are likely to impact on this:

- the increased importance of intermittent generation, which is priority-dispatched means that the range of potential price setting plants will increase;
- the increased interconnection will bring the total "demand swing" implied by interconnection up to 1,900MW, which will further increase the potential range of price setting plant; and
- over the period investment will take place in a number of new CCGTs, and a number of older, fuel oil fired plant condensation plant will close.

*Figure 5.4 Price duration curves for 2009/10, 2015 and 2020*

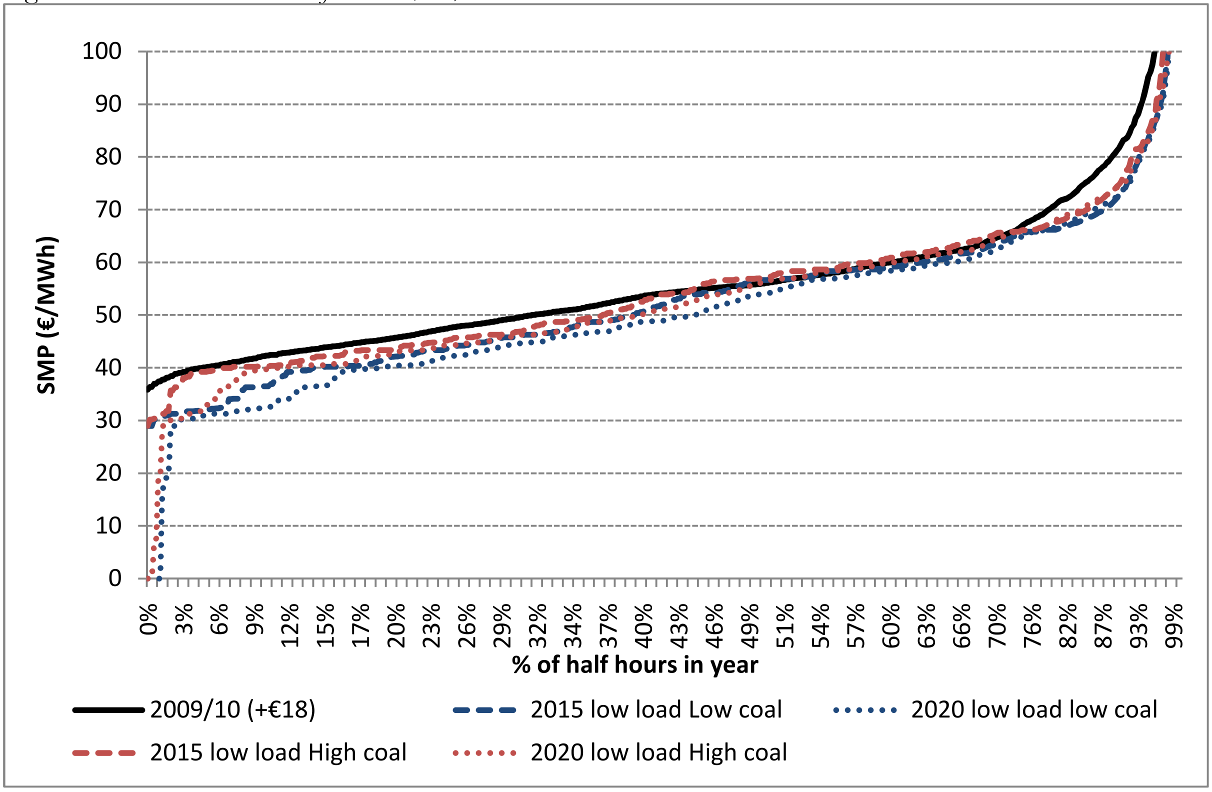



Figure 5.4 plots price duration curves for 2009/10, 2015 and 2020. The price level of the chart for 2009/10 has been raised by a constant to more clearly illustrate the relative slopes of the curves. The graphs have the following properties:

- The slope for 2015 and 2020 are steeper towards the lower end of the curve relative to the 2009/10 curve.
- The slope for 2015 and 2020 increases less quickly towards the upper end of the curve relative to the 2009/10 curve.
- The curves for scenarios where coal is in merit are steeper overall. This suggests a greater variability between high and low prices.

Overall the analysis is interesting because it suggests that the variability of SMP prices will increase somewhat (in particular if coal is in merit). It does however also suggest that the investment in CCGT capacity means that the likely type of price setting plant will become more uniform. Taken together this analysis has implications from the ability of suppliers to use fuel price hedges as a proxy for electricity forwards. The increase in slope suggests that the hedge will remain imperfect. The steadier slope towards the upper end of the curve does however also suggest that the range over which the price setting plant is determined by relative plant efficiency, rather than by fuel type, will increase. This indicates that predicting the price setting fuel type will become easier thereby reducing some of the risk of gas price hedges.

Figure 5.5 shows the monthly average prices[29] for the August-08 demand-weighted[30] average wholesale price including capacity payments (weighting by other months makes a negligible difference) compared with standard products for the same definition of prices. It shows that a simple average of base-load and mid-merit 1 would replicate the monthly average closely, although the variation from month to month is considerable, certainly compared to the margins on retailing.

*Figure 5.5 Monthly average wholesale prices for various products (source SEMO/RA data)*

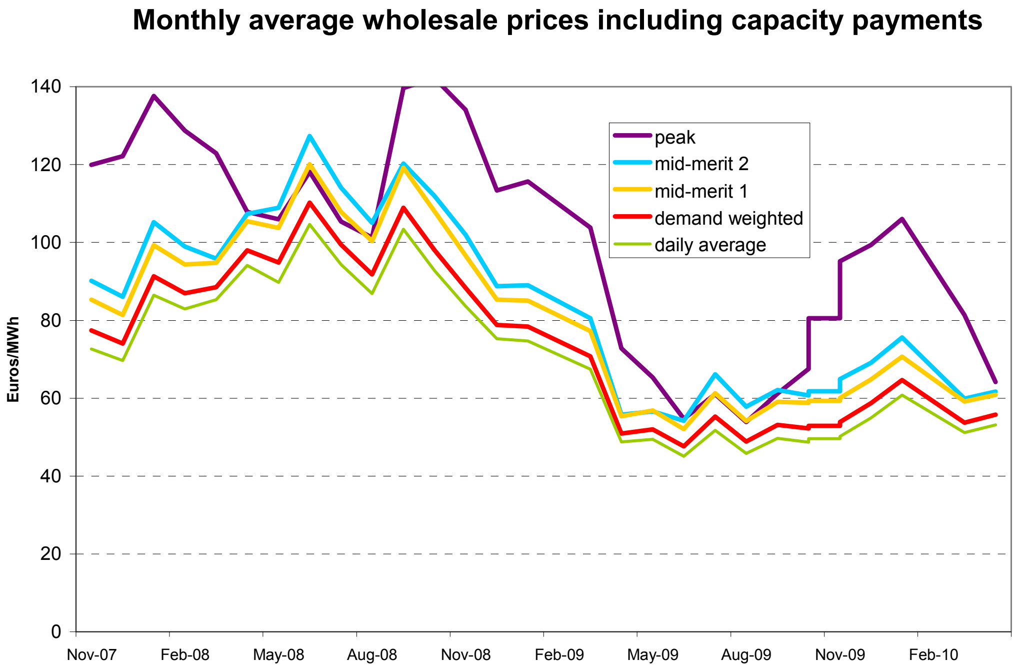



Figure 5.5 suggests that suppliers lacking a generation hedge might need a means of hedging their fixed price retail offerings. The combination of a base-load and mid-merit standard CfD, and possibly a one-sided CfD[31] with a high strike price should provide sufficient hedging, while keeping a small number of instruments would maximise liquidity, which should reduce the mark-up over the average of the spot prices. The main concern is that if ESB is vertically integrated then the Non Discrimination Obligation on ESB PG no longer induces ESB PG to offer competitive non-directed contracts, and the removal of the EPO on ESB CS will mean that it will have less of an incentive to shop around for better hedges. This means that other suppliers may be put at a disadvantage.[32] To judge how much they might be willing to pay a monopoly

[29] These are the averages for the calendar month, not the centred moving averages of previous figures.

[30] Demand weighting means weighting each hourly price by the fraction of daily demand (MSQ), in this case the average demand is for August 2008.

[31] A one side Cfd is one where compensation is only paid for movements in one direction.

[32] If ESB PG offers CS cheap contracts then it must do so to other suppliers, and this will be unattractive, but if PG offers expensive contracts then CS might find cheaper ones in the market and would be under an obligation to buy these instead, disadvantaging PG.

contract supplier we need to explore their residual risk after they have hedged using other types of contract, specifically forward fuel contracts.

A further point to note is that the NDC and PSO contracts offered are not licence conditions, but voluntary. The non-discrimination clause on ESB PG only applies to the extent that it offers CfDs. So ESB PG is not obliged by licence to offer CfDs (beyond DCs).

*Hedging with one-month forward fuel contracts: an illustration*

Below we illustrate the simple strategy of buying 1-month forward fuel contracts shortly before the start of the relevant month (trading closes two working days before the relevant month), and then offer contracts to domestic households based on that hedge[33]. The main risk is that if the fuel (and hence electricity) contract is out of the money, then customers will switch. That could be mitigated by offering customers contracts of varying durability (rather like building society deposits of typically instant access, or term deposits that have a penalty for early encashment).

*Figure 5.6 Monthly average wholesale prices, fuel hedges and revenue at risk (sources SEMO/RA data)*

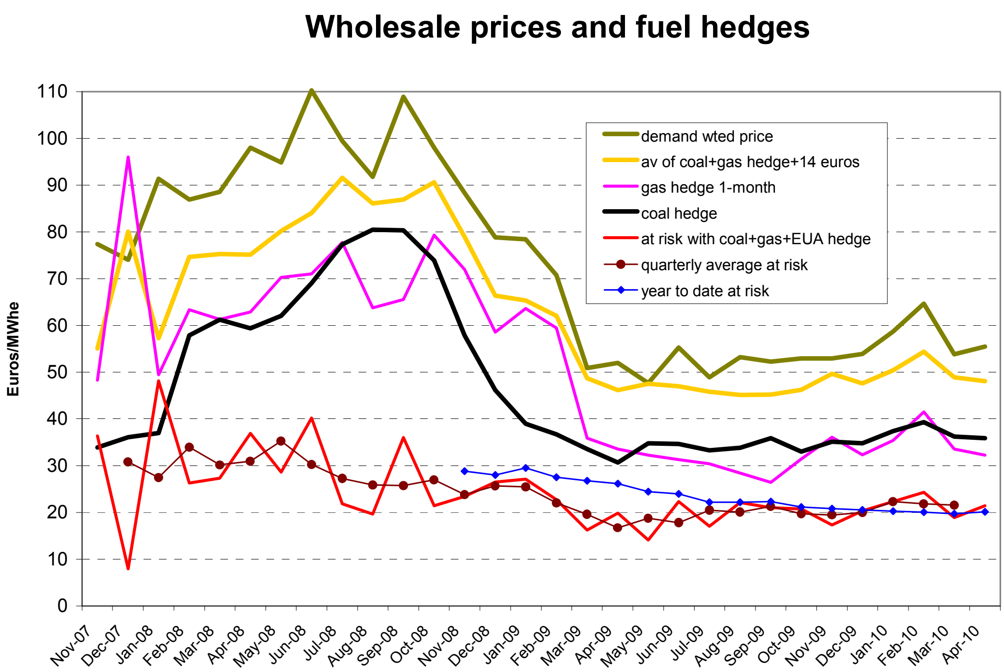



Figure 5.6 plots the monthly average August-08 demand weighted wholesale price, and the price of the 1-month ahead coal and gas contracts, in each case with the required volume of EUAs and adjusted to the coal and gas efficiencies (35% and 50% respectively). They are then averaged and €14/MWhe added to show how closely this composite hedge tracks the average wholesale demand-weighted price. The lower plots show the difference between the average wholesale price and the average of the coal and gas hedges, showing the difference as "at risk". The volatility if risk calculated over any period longer than one-quarter is quite low.

The simple rule followed is to offer a "retail" price (to which would have to be added all transmission, distribution and retailing charges) equal to the previous month's wholesale

[33] We recognise that consumer preferences tend to favour fixed price contracts, although this may change in the future with remotely read metering and supplier product innovation.

demand-weighted average price plus any increase in the average fuel+EUA forward price (equal weights of coal and gas generation costs). The profit on this contract is the daily average spot price less this fixed retail price. At the same time the supplier would buy 1x1MWht gas contracts and 1.5x1 MWht coal contracts + the relevant number (0.71) of EUAs (which would hedge the fuel costs of ½ MW 50% efficient CCGT and ½ MW 33.33% efficient coal-fired station, producing 1 MWhe).

*Figure 5.7 Fuel hedge profits and retail profits, monthly and year to date (sources SEMO/RA data, Bloomberg)*

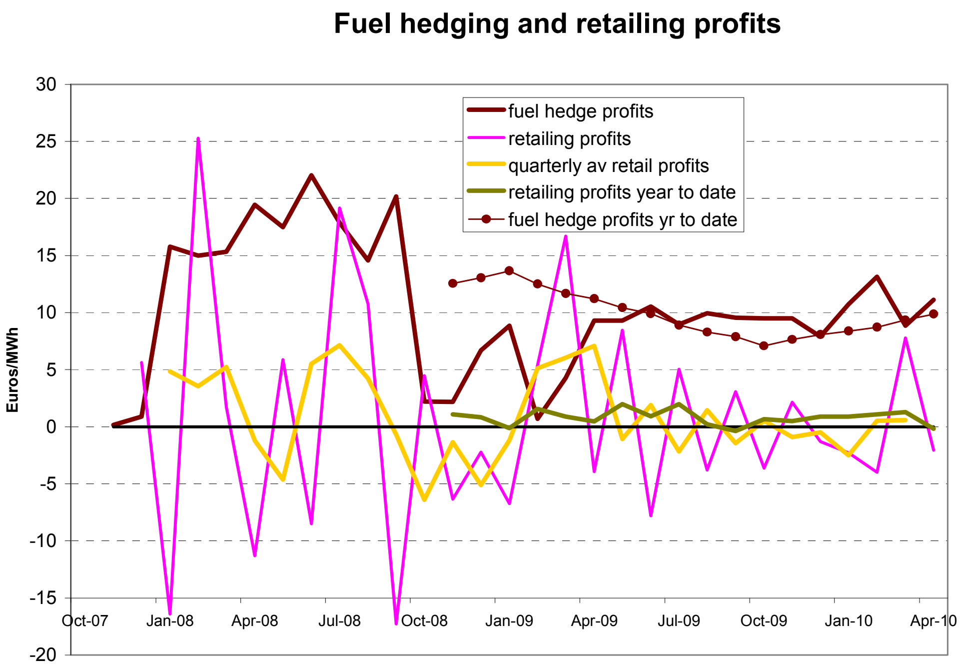



Figure 5.7 shows the resulting profit of selling at the fixed retail price for the month but buying in the wholesale market, and the profit of buying the fuel hedge and selling it back into the spot markets (gas, coal and ETS) to realise the fuel hedge profits. There is essentially no correlation between the two monthly series ($R^2$=0.007). On the other hand the profit averaged over a year from setting the retail price each month has a remarkably low variability of €0.7/MWhe.

So surprisingly, perhaps, the most effective way to reduce risk in retailing is to be willing to adjust prices each month in line with forward fuel price movements, and then average over a reasonably long period (a year is considerably less volatile than the quarterly figures shown in Figure 5.6). Clearly, though, this is less satisfactory than having the option of buying a 50:50 mixture of base and mid-merit forward electricity contracts on which to base the offered retail price, unless the risk premium were excessive.

This analysis suggests that, in the presence of the SEM pool system, retail suppliers do have a degree of ability to offer at least monthly fixed price contracts to its consumers. It would be able to offer these in addition to products that track the underlying electricity prices. It would however still remain a challenge for the retail supplier to offer longer term fixed price contracts if there were no electricity hedging contract available. This effect is however partly offset by the existence of the Directed and Non-Directed Contracts, as well as the PSO levy backed Contracts for difference, which, in combination with the fuel hedges increases the ability for non vertically integrated parties to offer products.

### 5.5.3. Conclusions on supply and demand for hedges

Based on the concerns raised by respondents and looking at the incentives on a stand-alone generators and suppliers it is likely that the demand for hedges would primarily be driven by the need of suppliers.

It is however important to note that looking forward, two additional factors may provide an increasingly strong incentive on generators and vertically integrated parties:

- Firstly as competition in the retail supply markets develops further this will continue to drive a need to optimise the underlying cost base. While it is possible for a vertically integrated party to provide a degree of optimisation, only sourcing electricity from its upstream generating arm, rather than contracting for cheaper generation, will expose the business to inefficiencies.
- Secondly the increased prominence of intermittent generation in the form of wind will mean that some of the current certainty of dispatch will be eroded.

In the following sections we examine the outlook for liquidity in the SEM further, with particular focus on the three types of contracts for difference; Directed Contracts, Non-Directed Contracts and PSO CFDs.

## 5.6. Outlook for liquidity

In order to inform policy options for hedging and liquidity we should consider the outlook for the different types of hedging products available. We do this in light of the discussion above regarding the fundamental impact of market design, we discuss the three main types of contracts in the SEM, what drives the volume offered through these routes, and provide commentary on the outlook for each of these contracts.

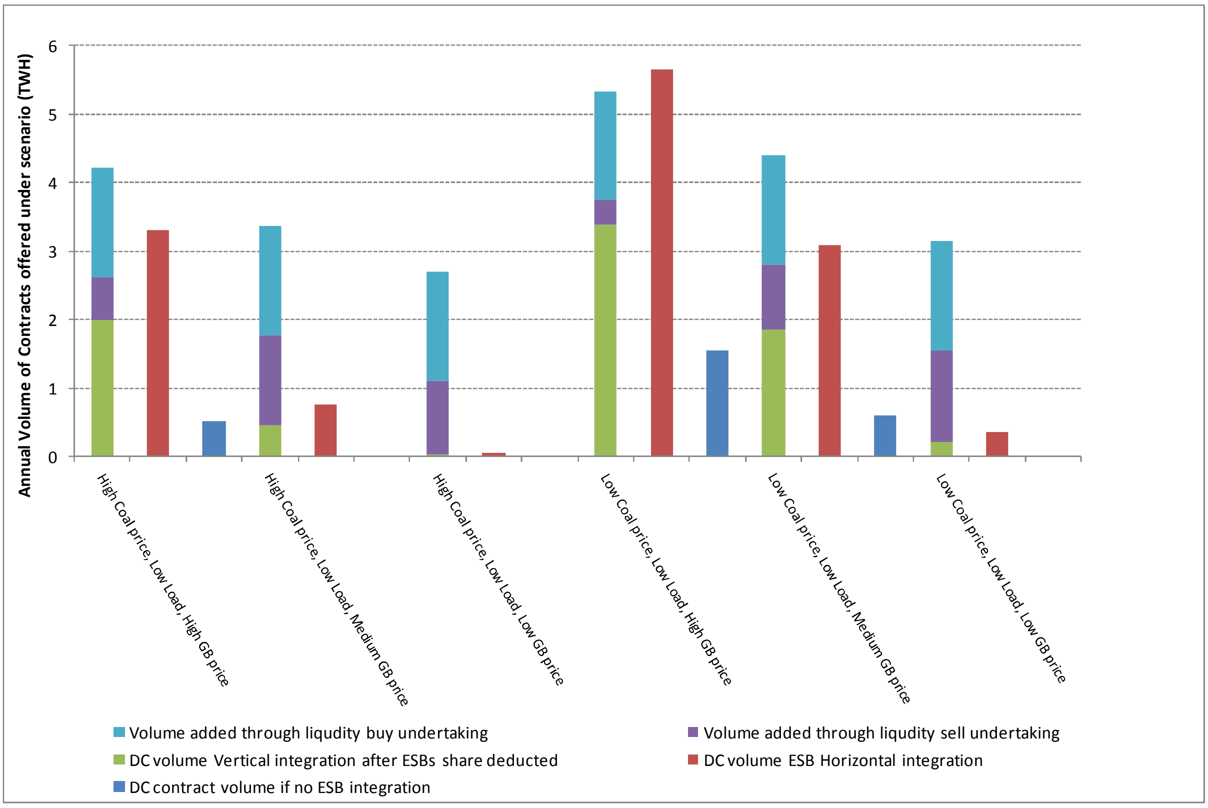
- The future outlook for Direct Contract volumes is driven by regulatory factors and market structure. In particular:
  - The volume of Directed Contracts is dependent on the evolution of future market power metrics. As the market becomes more competitive the volume of Directed Contracts provided to the market will decline.
  - The overall volume of Directed Contracts could however also be moderated by the RAs deciding to link the metric to a different critical number for HHI (or other measure), rather than the targeted 1150 index number currently used. Increasing the target to above 1150 would decrease the overall volume of Directed Contracts for any given level of market power observed by the metric. It could for example be observed that 1000 (the equivalent of 10 equal sized companies each with 10% market share) is often used as a critical number in competition analysis.
  - If the target critical value (and market power index used) is held constant, then the volume of Directed Contracts can be modelled based on market modelling output from Plexos.

- Drivers for Non-Directed Contracts are more uncertain. In principle these contracts are offered on a voluntary basis by market participants[34]. In practice there have however only been two providers of these contracts to date, and no new providers have been observed despite the contracts for periods commanding a significant premium in price above similar product Directed Contracts.

- The PSO backed CfD volumes are also influenced by regulatory factors. The outlook for these volumes are uncertain due to the fact that shortfalls or surpluses made by these contracts are passed on to consumers.

- The RAs have undertaken forward looking modelling of scenarios for the SEM[35]. Based on these scenarios we have undertaken a higher level estimation exercise to provide an indication of the potential volumes of Directed Contracts which would be available under each market structure. The results of this estimation exercise is presented in Figures 5.8 – 5.9.

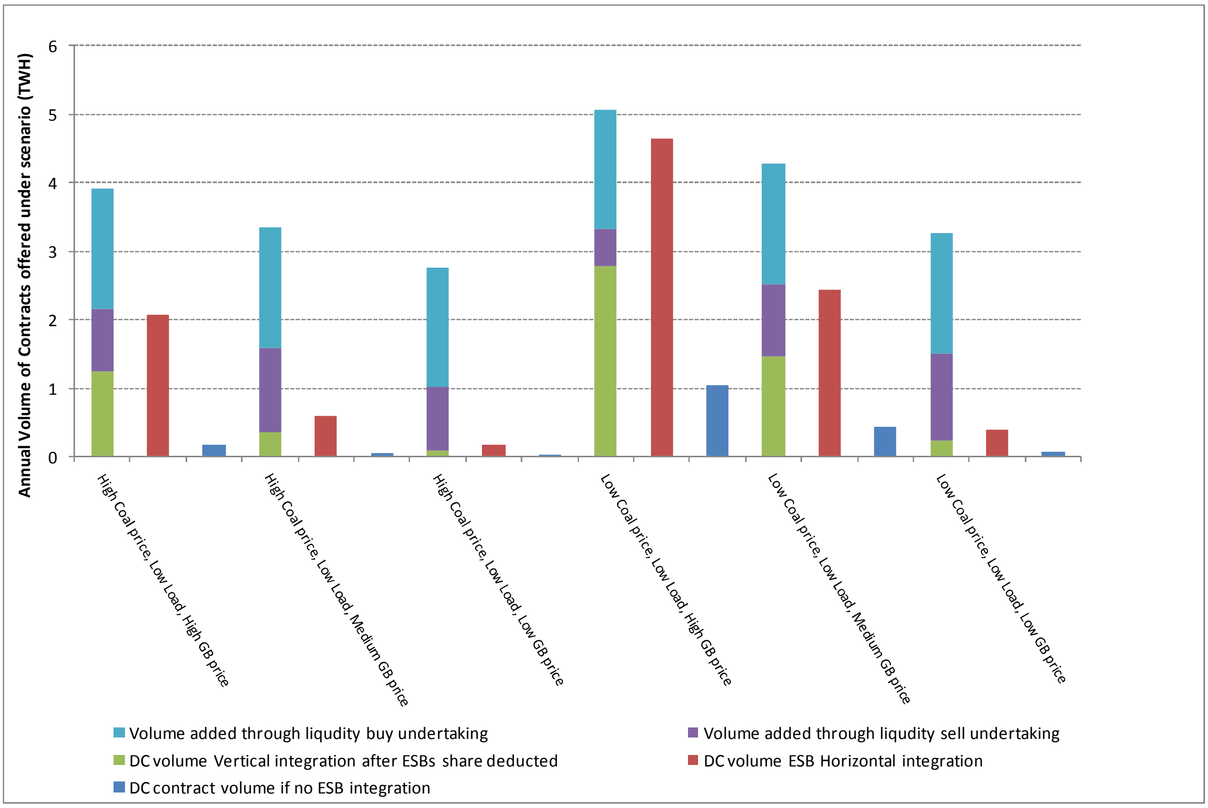
*Figure 5.8 Estimated volumes of Directed Contracts and liquidity buy and sell volumes for 2015 scenarios*




[34] We note that the contracts offered by NIE PPB are slightly different from the NDCs offered by ESB PG in these are linked to the PSO in Northern Ireland

[35] The assumption behind this analysis is outlined in section 3.8

*Figure 5.9 Estimated volumes of Directed Contracts and liquidity buy and sell volumes for 2020 scenarios*




The estimation in the charts provide an indication of how the volumes of DCs may develop, as well as the liquidity sell and liquidity buy commitments proposed by ESB. The legend of the charts is as follows:

- **DC volume if no ESB integration:** This is the volume of Directed Contracts it is estimated that ESB PG would provide if there is no horizontal integration.
- **DC volume if ESB integration:** This is the volume of Directed Contracts it is estimated a horizontally integrated ESB PG and ESBI would be required to provide.
- **DC volume after integration after ESBs share deducted:** This is the volume of Directed Contract it is estimated that a *Horizontally and Vertically* integrated ESB Group would be required to provide if it is allowed to internalise the volume of DCs it is entitled to owing to its own consumer load (ESB's customer load is assumed to be 40% of demand).
- **Volume added through liquidity sell undertaking:** This is the estimated volume of contracts the horizontally and vertically integrated ESB Group would sell *on top of the volume of DCs it would also be required to provide.*
- **Volume added through liquidity buy undertaking:** This is the estimated volume of contracts the horizontally and vertically integrated ESB Group would offer to buy through its liquidity buy commitment (assuming ESB's customer load is 40% of demand).

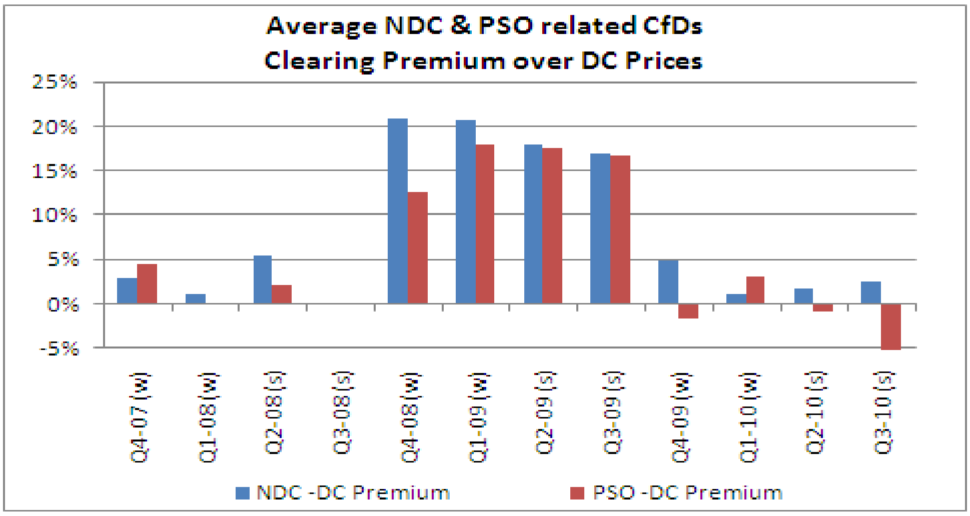
It is important to note that the liquidity buy commitment does not provide hedges to other suppliers, but rather provides hedging opportunities for other generators. Given this it would contribute to the total volume of hedges available in the SEM. It is nevertheless important to note that these hedges provide trading volume and aid the development of price discovery in the market.

It is interesting to note that the volume of DCs varies significantly with several variables. In particular it is higher in scenarios where coal prices are low relative to the gas price. Concentration in this scenario increases since the Moneypoint and Kilroot coal power stations, belonging to the two largest generators ESB and AES respectively are then in merit at the expense of other generators. Similarly if capacity margins are lower due to prevailing exports to GB (when the GB price is higher) then the concentration of spare capacity to ESB and AES pushes up the HHI resulting in higher volumes.

### 5.7. Potential issue of market power in the market for contracts

One observation worth making regarding the SEM contract market is the potential for market power distortions in the market for forward market contracts. In particular it has been observed that the prices of the Non-Directed Contracts (and PSO backed CfD) achieve a significant premium over the DC prices. This is illustrated in Figure 5.10.

*Figure 5.10 NDC and PSO CfDs clearing Premium over DC Prices (source data from Regulatory Authorities)*




For Directed Contracts both the price and quantity of CFD contracts are determined through a regulatory process. As the contracts are made available to downstream parties based on their supply portfolio the DCs gives parties the opportunity to hedge a proportion of their load at a simulated electricity forward price. Given that presence of the Bidding Code of Practice and Market Monitoring Unit effectively ensures that the SMP price is set at a level which is very closely related to the short run marginal cost of the price setting plant, the DC price setting calculation should in principle closely proxy what an competitive traded electricity forward price would have been in the SEM given those underlying conditions.

Figure 5.7 suggest that it has been possible for suppliers of contracts to achieve contract prices above those of Directed Contracts for periods (including over 10% above the DC price which is often cited as a critical number in competition economics if compared against a competitive price). It is however also notable that these premiums appears to have been volatile over time.

*Figure 5.11 Volatility in the NBP gas price (source Bloomberg)*

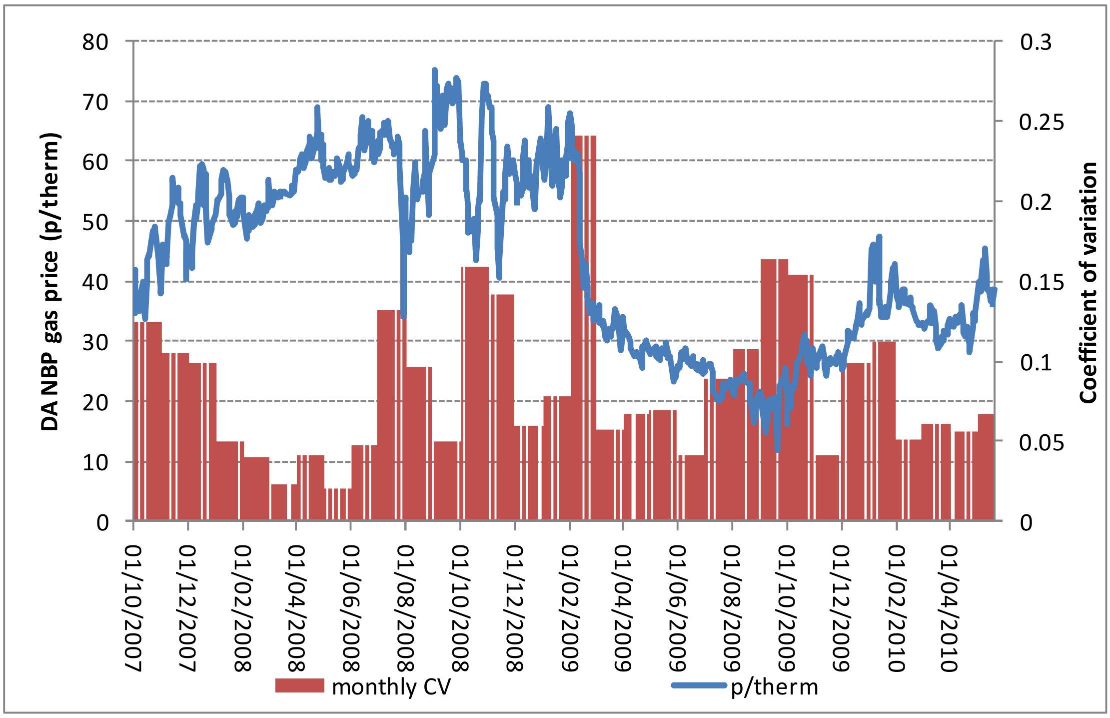



Figure 5.11 shows the evolution of the day-ahead NBP gas price over the same time period, as well as the monthly coefficient of variation (a standardised measure of volatility or variability). As the NBP price is a key driver of the SEM SMP price it is can to an extent be expected that volatility in the gas market could drive demand for hedges in the SEM. It is notable that the period corresponding to the most significant period of premium in NDC prices above DC (Q4 2008 – Q3 2009) corresponded to a period of expected undersupply in the GB gas market. When the NBP supply/demand situation eased in early 2009 both the prompt and forward prices fell significantly. This would however not be visible in the NDC prices as these were fixed when sold during the summer of 2008. Another test that it might be worth conducting is to compare the premium paid for forward gas contracts over buying spot – if that were comparable to the NDC premium then one might infer that both the Gas forward market and the NDC market were comparably competitive.

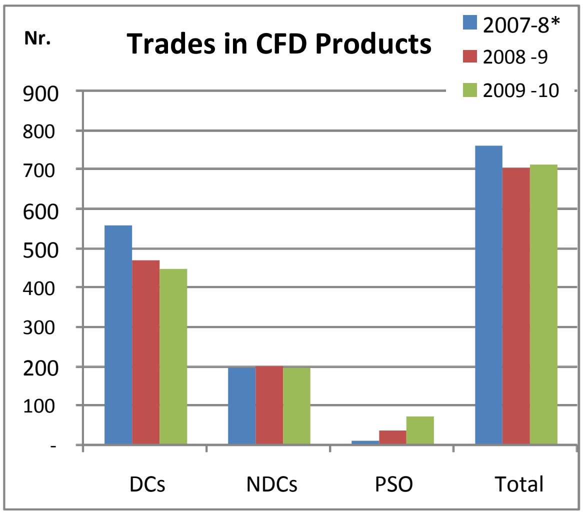
A plausible explanation for the premiums of NDC prices above those of DCs could therefore be that there was an excess demand for hedges over the period. This alone does however not answer the question if there may be market power in the market for contracts, but may suggest that price could be higher due to too few contract being available (which could be interpreted as holding contracts back in order to increase their price).

It is also worth adding a number of other observations regarding the trade in Directed and Non-Directed contracts

- Number of trades – Figure 5.12 suggests that the number of transactions have remained relatively steady, but the ones on the NDC side are clearly very limited, in particular when one considers that in terms of volume the NDCs make up a larger volume than the DCs.

- Number of market participants: the number of market participants is significantly limited with only 2 sellers and 7 buyers

*Figure 5.12 number of trades in CFD Products (source data from RAs)*




While normal forward markets are difficult to manipulate by reducing the supply of contracts it should be noted that this is not a liquid or market. As contracts are offered through auctions the suppliers of contracts are arguably not using the offer price as a route to increase the price. Instead if there is an imperfection it is likely to be in the form of restrictions to the total supply of contracts. The supply side drivers of NDCs are not clear and appear to largely be based on consultation between the two suppliers and the regulatory authorities. It is possible the opaque nature of the NDC quantity (which may still be perceived as a regulatory tool as it is offered by formerly incumbent generators) could act as a barrier to other parties entering the market.

It is possible that the premium of NDC prices above DC prices are caused by two current market features:

- undersupply of contracts; and
- a degree of oligopoly in the setting of quantity of products coming about due to a lack of parties offering contracts (as opposed to collusion)

In either case these risks implied by these features would be reduced with entry into the market by other parties, or the premiums be competed away if arbitrage against products in the BETTA market becomes available through increase interconnection.

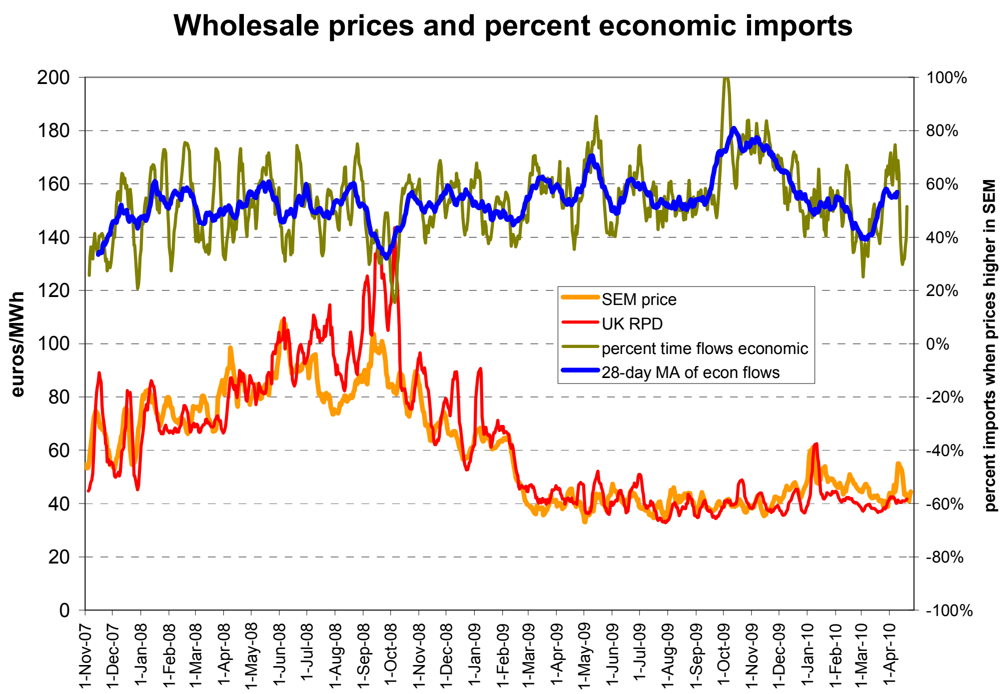
It is however possible for the imperfections in the NDC market to have an impact on the ability of parties to enter or expand in the retail supply market. It may be worth considering options for supporting the entry of smaller suppliers to help enhance competition in the retail sector. This could take two forms:

- Regulatory backed market making[36] for smaller suppliers. This will facilitate entry to the retail market. The measure would be removed once it is deemed that smaller suppliers could access hedges effectively.
- Introducing a liquidity provision mechanism with an ex-ante fixed quantity. This will both make it easier for parties to predict the minimum volume and types of contracts which will be available in the future, and therefore price risk. This may also serve as an incentive for other generators to offer contracts on a competitive basis if they believe that they could profitably beat the prices offered through the mechanism.

### 5.8. Effect of interconnectors arrangements

As discussed in the previous section, interconnection could potentially both reduce the risk of competition issues in contract markets, directly facilitate entry and provide additional opportunities feeding liquidity. It is however important that the regulatory arrangements applying to the interconnectors are carefully designed so that trading can effectively take place. If this is not the case then the benefits of additional interconnection capacity may be limited or lost. This is important both in the context of the existing 450MW Moyle interconnector, and in particular the 500MW East-West interconnector currently under construction. These cables will enable a total swing of 1,900MW of capacity between the SEM and GB, against an SEM peak demand of between 6.5 and 7 GW in 2015[37].

*Chart 5.13 Interconnector flows across Moyle (source data from Regulatory Authorities, Bloomberg, Elexon)*




[36] We discuss market making further in the section 6 of this document.

[37] Eirgrid Generation Adequacy report 2010-2016

Figure 5.13 illustrates the recent experience of the current Moyle interconnector between the GB market and the SEM[38]. It is notable that the flows across the interconnector appears to have been economic only around 50% of the time, thus suggesting that electricity frequently flows in the opposite direction compared to what would be expected given market prices. This is likely to be due to imperfections either in the capacity allocation mechanism for the interconnector, or compatibility of the GB and SEM markets (particularly the ex post price determination on the SEM).

We would like to stress the importance of the work currently underway to facilitate intraday trading in ensuring that the benefits of interconnection can be achieved in the context of compliance with the relevant EU regulation and SEM regional integration.

### 5.9. Role of information

In order to promote competition and to facilitate the development of traded market liquidity transparency is a key factor. In order to increase the likelihood of the SEM appearing attractive to financial traders, the price formation mechanism needs to be seen as sound and transparent. It is also important that there are not significant information advantages available to incumbents. While the SEM arguably has good information available to market participants, the Regulatory Authorities and Market Operator should be vigilant to ensure this remains the case.

Electricity trading enables parties to manage their exposure to revenue and cost risks. Buyers and sellers of electricity can hedge their exposures to the often volatile nature of electricity prices by signing forward agreements.

One of the key factors needed in order to enable this to happen effectively is that sufficient information needs to be available in order for the contracting parties to assess the factors influencing the price drivers. In the context of the electricity market information transparency becomes an important factor as smaller players, or even utilities active in other countries, will be less willing to engage in trading in a market if it perceives that the incumbent generators and suppliers have a significant advantage in the availability of information.

In light of this, an important tool in enhancing the potential for forward trading is enhancing the level of information available to market participants, hence enabling them to make more effective decisions and ensuring that they are able to engage in forward transaction in a fair way.

In addition to transparency regarding the factors influencing price, another important aspect is whether the trading is conducted physically or financially. A physical contract requires the signatory to physically deliver, or take delivery of the product on the delivery date. If there is insufficient liquidity in the short term market, then a party without physical assets may find itself unable to "balance" his position and may become exposed to imbalance charges. If liquidity is sufficient then he will be able make trades to balance the position. In financial trading the forward contracts are not for physical delivery, but rather settled against a reference price, often derived from a short-term physical market (like NordPool ElSpot). For financial trading to be able to develop it is however necessary for this reference price to be perceived to be reliable and

[38] It should be noted that until recently GB arrangements required Moyle to pay Transmission Use of System Charges, which due to the GB connection location in Scotland where high. This meant that it was relatively expensive for a GB party to import electricity through Moyle.

reflecting solid market fundamentals. The reference price transparency is an area where the SEM market design in strong and where the BCoP and Market Monitoring Unit should continue to play an important role in ensuring confidence in the price formation mechanism remains high.

A potential limited intervention that could have an important impact on market confidence would be a transparency programme for market data. Market participants have highlighted that some market features could require additional explanation, or for data to be published such as:

- Forecast transmission outages and constraint treatment;
- Forecast Generator outages, or a requirement to publish updates to generation outage plant before participating in auctions;
- Investigation and reporting by the MMU; and
- Forecast future DC/NDC volumes.

A number of different, and not necessarily mutually exclusive measures to enhance transparency could be adopted.

- A strict approach to transparency would be to adopt an approach similar to that adopted by Nordpool, where market participants are required to make public certain information through messages to the market before they are allowed to execute trades through the system. Such information includes long term planned outages for generating units. In addition to this unplanned outages needs to be announced through urgent market messages as well. In the context of the SEM such an approach could help facilitate potential future relaxing of the bidding code of practice.
- The RAs could establish a working group made up of market participants with terms of reference to identify additional data items needed for the market to be able to operate efficiently. This approach is however likely to require some activity by the regulator since the publication of some data may prove to be controversial with market participants.[39]
- A market entry handbook. The regulatory regimes and various interventions that make up a quasi-regulated market like the SEM electricity market are by their nature specialised, detailed, and have evolved over time. Parties investigating entry into the SEM (if only for trading) would need to invest significantly in understanding how these rules impact on market participants. A handbook could be developed and maintained in co-operation with market participants to ensure this information is less costly to maintain.

Transparency measures can however only help encourage entry by facilitating understanding of the price formation process and market dynamics. Such measures do however not directly provide hedging volumes that are important for downstream parties to be able to enter or expand.

[39] We note for example that the publication of real time gas flow data by subterminal which was introduced in the GB market in 2006 was opposed by several parties for commercial and contractual reasons. Similarly the publication of aggregate storage volumes at LNG facilities was opposed on the grounds that it was commercially sensitive. Both items are now published through National Grid Gas, the system operator for gas transmission system in GB.

## 5.10. International experience of liquidity

Several other energy markets have taken steps to address concerns over market liquidity over the past few years. The most recent and in debt study undertaken was probably that of the GB regulator Ofgem, but NordPool and the experience of New Zealand are also worth considering in this context.

*Liquidity concerns in BETTA*

The regulator started its investigation after electricity market liquidity was identified as a potential issue in the context of an investigation into the level of competition in the retail energy markets. Over the same time period concerns was also raised about a trend towards vertical integration, with the large non-vertically integrated generator, British Energy, being bought by EdF, and later a proportion of it bought of Centrica. Both of these companies are vertically integrated companies. Box 5.1 provides a summary of policy proposals made by the GB regulator following its review, as well as an indication of the current status of this programme.

*Box 5.1 Ofgem's programme of work for liquidity*

**Work in GB on liquidity**

Liquidity Proposals for the UK Wholesale Electricity Market

Ofgem want to improve the liquidity in the UK wholesale electricity market. There are a number of steps it wants the market to improve this, and they will assess the solutions provided using a number of criteria:

- **High volumes traded in standard products.** Ofgem will review how the volumes of standard baseload and peak products are developing, and will desire evidence that volumes are sustainably increasing.
- **The availability of key longer dated products and/or financial derivatives.** A key consideration will be to assess the ability of market participants to hedge their positions over longer periods of time. For indicators of market development, Ofgem will evaluate the emergence and availability of appropriate products, and consider whether or not there is a trusted reference price for financial derivatives and forward products
- **Use of trading platforms by small/independent suppliers.** This requires developing products with a clip size, shape and duration to meet small suppliers' needs. If small traders cannot access the market to hedge against risk, then increased trading volumes on their own may not improve retail market contestability.
- **Positive feedback from small/independent suppliers and potential entrants.** Ofgem will survey small/independent suppliers and potential entrants to determine whether their trading conditions are improving.

If the market doesn't improve liquidity (as measured by these criteria) within the timeframe desired by Ofgem then it intends to introduce some policy remedies. These may include:

- **An obligation requiring large generators to trade with small/independent suppliers:** This would require large generators to offer terms when approached by small suppliers, and may be extended to require large suppliers to offer purchase terms to small generators. Currently no such obligations exist.

- **Market making arrangements**, supported by a licence obligation on the Big 6 to provide electricity in defined products: The electricity would then be available to all market participants through a trading platform.

- **Mandatory auctions:** these may focus on the prompt market (in order to develop trusted reference prices and accordingly more financial derivatives) and, as an alternative and perhaps as a complement, it may also focus on longer term products. All large generators would be obliged to offer volume at auction.

- **Self-supply restrictions on large, vertically integrated utilities:** this would limit the extent a company's generation business may supply its retail business. As a result, a proportion of their requirements would have to be traded on the market.

These interventions aim to improve liquidity (including in forward products) in the UK wholesale electricity market, and to improve the ability of small or independent suppliers and potential new entrants to meet their wholesale energy purchasing and risk management needs. It is hoped that this will improve competition in the supply market.

**Summer 2010 Assessment**

Ofgem concluded in its Summer 2010 assessment of liquidity that the GB wholesale electricity market is performing well against some of its eleven metrics of liquidity but less well against others. It has summarized the results of its research into positive and negative developments.

On the positive side, it highlights four points:

- **The annual trend in aggregate churn has been rising since 2005:** the aggregate churn peaked in 2002 at 6.8 times the rate of physical consumption. It then slumped to a low of 2.0 in 2005, and has been rising steadily since, increasing to 3.9 in 2009 and is forecast to reach 5.0 in 2010.

- **There has been industry-led innovation and new development, and there are plans to introduce new derivatives:** There has been a move towards exchange based trading over the past year and a new exchange, N2EX opened in January. It's levels have been stable but relatively low. N2EX will be offering cash settled futures contracts later this year.

- **The market generally meets the needs of large vertically integrated market participants:** the products offered and the platforms they are available on cater to the needs of large market players.

- **There are some important positive drivers that will impact the market over the medium term:** connecting markets through interconnectors like Britned will increase market participation by European energy firms, which increase the size of the market and improve overall liquidity.

However, on the negative side there are an additional four points:

- **Overall churn remains well below that seen in the most liquid electricity markets:** Aggregate churn is significantly lower than in the German and Nordic wholesale electricity markets, where the values for 2009 were 9.6 and 7.6 respectively.

- **Liquidity further along the curve remains weak, and there is evidence of increasing bid-offer spreads:** Whilst spreads on near-term products have fallen over the past two years, those further along the curve have increased. Also, the proportion of baseload traded volumes further along the curve has declined since 2006. Independent market players who responded to Ofgem's questionnaire unanimously agreed that they had not observed any improvements in liquidity further along the forward curve.

- **There has not been a major increase in auction volumes and price transparency:** High levels of exchange-based trading allows for the creation of robust reference prices and greater transparency, however, OTC trading predominates in GB.

- There is ongoing dissatisfaction from non-vertically integrated market participants about their ability to meet their wholesale power hedging needs: the lack of suitable financial products, offered for appropriate time periods and available in small clip sizes, is seen as discouraging entry to the market as smaller/independent players cannot hedge their risk appropriately, and product diversity has fallen in GB since 2003. Further, the small number of counterparties offering these products is also a matter of concern for small/independent participants.

Ofgem believes that as further improvement is required and as it is not implausible that these improvements shall not be sustained, it is prepared to further develop the interventions set out above. This is conditional on the reforms being cost effective and consistent with current regulatory aims.

The key lessons from BETTA for the Regulatory Authorities is that contract liquidity in electricity is problematic both to investigate, and to design remedies for. The BETTA investigation takes place against a background of a much higher level of liquidity, with a regularly trade spot market. Even under these relatively favourable circumstances, and with several industry initiatives underway, Ofgem has been actively engaging on this subject for over two years[40].

*NordPool*

NordPool has managed to achieve a higher degree of liquidity than most European electricity markets. In the Nordpool area the wholesale markets where de-regulated by increasing the size of the market from originally only Norway, to also include Sweden and eventually Finland and Denmark. This enabled the national market structures to remain fundamentally in place.

NordPool operates a non-mandatory pool system where participants can either bid into the pool on a gross or a net basis.

- with gross bidding the participant bids in all his generation and all the demand through the system; and
- with net bidding the generator would only bid in the residual demand they need to meet their load.

Currently over 70% of volumes are submitted through the Pool on gross bid basis. This has the effect of generating good price formation at the day-ahead stage. Financial forward market then settle contracts against the day ahead reference price.

[40] Electricity market liquidity was identified as an area needing further study in the initial findings report for the Retail Supply Probe, published in October 2008. http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=4&refer=Markets/RetMkts/ensuppro

A number of factors have contributed to create favourable circumstances within which liquidity and trading effectively developing in the Nordpool are:

- Low market concentration with many small generators.
- A very large proportion of generation is traded through the pool system (i.e. it has almost as good price formation as a gross mandatory pool). This has been achieved through two factors:
    - discounts to market participation fees have been offered to participant bidding in on a gross basis;
    - an undertaking from the larger generators to bid in on a gross basis; and
    - several of the larger parties have acted as market makers. Since inception over 20 parties have operated as market makers in Nordpool.
- In the NordPool region the supply markets have been national, while the generation market became regional. This had the effect of encouraging competition and entry into other market areas.
- Sweden and Norway have surplus generation, mainly in the form of nuclear and hydroelectric power, while Denmark and Finland are short on generation and more exposed to conventional fuels such as natural gas, coal and oil.
- The large proportion of hydropower in NordPool means that storage levels in the water magazines become an important driver for the availability of generation.
- The region has interconnection, not only within itself, but also to Russia, Estonia, Germany, Netherland and Poland. Each of these links presents trading and optimisation opportunities for parties.
- A very strong emphasis was placed on transparency from the outset and the rules governing information release are enforced strictly.

Critically in the Nordpool region generators identified market liquidity and effective forward market price formation to be an important, and valued feature. They therefore made commitments to ensure a large volume is traded through the physical Day Ahead Spot Market. This has been key factor in the development of financial trading in the forward market.

Nordpool has also illustrated that information availability on subjects such as generator outages could be improved in many parts of Europe.

*New Zealand*[41]

The New Zealand energy markets where aggressively de-regulated during the 1990s followed by light handed regulation based on the threat of re-regulation, information disclosure and self regulation, as well as competition policy prohibiting anti-competitive behaviour. Following

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[41] Competition in the New Zealand gas sector is explored further in the paper 'New Zealand Gas Industry Regulation, Lessons to learn for the British Energy Sector" (report by CEPA for Ofgem RPI-X@20 project, March 2009. http://www.ofgem.gov.uk/Networks/rpix20/ConsultReports/Documents1/NZ%20gas%20regulation.pdf
A good summary on the proposed market maker arrangements in electricity is available in appendix 4 to Ofgem's Liquidity proposal for the GB wholesale energy market: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Liquidity%20Proposals%20for%20the%20GB%20wholesale%20electricity%20market.pdf

concerns over the state of competition in both the gas and electricity markets regulation has been raised, investigated and reforms proposed.

On the electricity side the new electricity trading arrangements large generator/retailers will be required to develop exchange traded arrangements, including requirements to offer bids and offered with a maximum spread. The aim of this measure is to provide access and contestability in both the generation and retail sectors. The market maker approach was identified to help above and beyond buy/sell obligations which could be avoided by manipulated by setting high reservation prices.

Another key lesson from the New Zealand electricity market is that too quick de-regulation can have significant adverse consequences, requiring costly interventions ex-post.

## 5.11. ESB's liquidity Proposals

In this section we discuss the proposed liquidity undertaking put forward by ESB to the SEM committee. Box 5.2 provides a summary of the liquidity undertaking submitted by ESB. A more complete version of this proposal is presented in Annex 5.

*Box 5.2 Liquidity undertaking proposed by ESB*

| Summary of Proposed undertaking |
|---|
| ESB is proposing the following binding commitments, following the removal of the business separation constraints between PG and CS.<br><br>ESB's PG is currently providing the great majority of Contracts for Differences (CFD) in the SEM market, through the mandated Directed Contracts (DCs) and the voluntary (NDCs). These products allow suppliers and generators to trade away the risk of their exposure to the SystemMarginal Price (SMP) in the SEM. One of the key concerns regarding the removal of separation between ESB's PG and CS is that ESB will be able to hedge against risks internally, and as a result will provide lower levels of liquidity than is required by the rest of the market to meet its risk management needs.<br><br>In its undertaking, ESB commits itself to continuing to provide liquidity in the case of removal of separation. It believes that because of the low levels of trade in SMP CFDs, the low volatility in CFD prices, and the regulated nature of the market means that a low level of liquidity is required: unlike other wholesale electricity markets, parties do not need churn equal to five or six times their underlying position traded, they only need match their existing physical position, which amounts to a relatively small volume.<br><br>ESB does however highlight that the greater the volume commitment it has to make to the provision of external liquidity, the less valuable and relevant the removal of separation will be. The greater the market and counterparty risk ESB has to take on, the higher the cost of such liquidity provision for the whole market. ESB argues that other market actors have a role to play in providing liquidity for risk management, and believes that the current situation and the disproportionate share of CFDs that PG provides (especially considering its falling market share) is 'unreasonable and unsustainable'.<br><br>**The shape of ESB's liquidity undertaking:** ESB proposes that it will offer annual, monthly and quarterly products (though it believes the annual products will be in the highest demand) and it also will lower the minimum contract size to 0.1MW, as a support to new entrants.<br><br>Despite the lower demand for CFDs from generators than the demand from suppliers (because of the SMP conditions, fixed prices leave generators exposed to fuel price increases) ESB has also |

committed to offer products where generators swap SMP exposure for a fixed revenue stream, in an attempt to support the entry of new generators.

The two key components of ESB's proposal are a "liquidity sell commitment" and a "liquidity buy commitment". These are summarised below.

**Liquidity sell commitment:** ESB will offer a Liquidity Sell Commitment (LSC), including its DC commitments, of 25% of PG forecast output, based on its commitment to reduce its generation market share to 40% of the SEM. ESB will offer proportionately more or less of its output, depending on whether or not its market share is above or below the 40%.

If the LSC were to reduce PG's capability to internally hedge at least 30% of ESB's forecast demand, or if ESB's access to other forms of SEM risk management were reduced, ESB would lower the LSC by that amount.

The LSC will cease if:

ESB's share of Generation in the SEM falls below 30%

The commissioning of an additional interconnector

The GB and SEM markets become effectively coupled, or

There is a fundamental change in the SEM market rules.

**Volume of Liquidity Buy Commitment (LBC):** ESB will offer a LBC of 10% of ESB's forecast demand based on a 40% SEM market share, and will offer proportionately more or less, depending on whether or not its market share is above or below the 40%.

If the LBC is too large, it will defeat the purpose of removing separation and ESB's demand will become significantly overhedged. As a result, it wants to make its LBC dependent on the degree that its demand is internally hedged after it has discharged the LSC. If, after the LSC is taken into account ESB is significantly long on generation, the LBC will be reduced to that extent. The criteria for the cessation of the LBC are the same as those for the LSC.

### 5.12. Summary on liquidity

While it is important to recognise the strong benefits a liquid contracts market can provide, it is also important not to lose sight of fact that contract market liquidity is a means to an end. The SEM has only been in operation for a limited time period. It is important to keep in mind that trading in other market have taken time to develop, and that interconnection could facilitate significant increases in liquidity, as well as to an extent compete away premiums of Non-Directed Contracts over Directed Contracts by providing additional volumes. This will however fundamentally be dependent on effective arrangement for interconnection and alignment of GB and SEM trading arrangements to minimise the cost of trading, and to facilitate within day trading. It should also be remembered that there are other ways of hedging risks in various forward fuel markets as well as the GB electricity market (which is driven by similar factors), and that the way that the spot price is determined may reduce the need for hedging as it is more strongly related to these fuel price fundamentals.

While such development may still be a couple of years distant, and it may take a period for confidence to develop in the systems it should nevertheless be recognised that there are features of the SEM that helps promote liquidity, in particular:

- ring fencing between the large supply and generation of companies[42]; and
- requirements on large generators to sell a proportion of their capacity through Non-Directed Contracts.

Both of these measures could clearly facilitate contracting liquidity by increasing both the demand for and supply of hedges. It should however also be recognised that they lead to potential inefficiencies by limiting the freedom and ability of parties and shareholders to adopt their own risk management strategies, and impose transaction costs on market participants. If these measures are retained for longer than necessary they could ultimately lead to higher than necessary consumer bills and therefore have a detrimental effect on consumer welfare. It is therefore important to carefully balance and monitor the expected benefits of any measure to increase liquidity so that they can be removed when the market has matures sufficiently.

Our analysis has shown that, in the presence of the SEM pool system, retail suppliers do have a degree of ability to offer at least monthly fixed price contracts to its consumers, but that it would remain a challenge for the retail supplier to offer longer term fixed price contracts.

This, combined, with the key lesson from BETTA that contract liquidity in electricity is problematic both to investigate, and to design remedies for, would argue for a continuation of ring-fencing for a further period.

Finally, it is worth noting in the context of liquidity that the Directed Contracts volume have the effect of reducing demand for hedges by suppliers, and reducing the potential size and potential volumes of a traded market. As wholesale market concentration declines the exposure of suppliers to the SMP increases and thereby also the potential demand for hedges. Measures that help reduce concentration in the wholesale market is therefore also likely to help increase the demand for hedges (or vertical integration) by suppliers in forward market.

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[42] It should be noted that while Chart 5.8 and 5.9 of this document indicates that higher levels of contracts may be available under integration scenarios these charts only show the DC volumes and volumes made available through liquidity release undertakings. Vertical integration by itself is however naturally detrimental to liquidity and the incentives to trade by removing buyers and sellers from the market.

# 6. POLICY OPTIONS

In this section we discuss the options for policies and measures to promote competition under different potential structural scenarios for the SEM.

This includes considering amendments to the market power mitigation strategy, as well as potential other measures to promote competition. We also outline our proposals to help facilitate hedging by suppliers and stimulate the emergence of traded market liquidity under these conditions.

Finally, we give CEPA's initial recommendations on any amendments to the market mitigation strategy and our preferred option(s) to promote competition.

## 6.1. Introduction

Before setting out the policy proposals it is worth re-iterating the objectives of the SEM Committee, as well as the objectives of the market power mitigation strategy. Certain of these can effectively serve as criteria against which to assess the options presented below.

The objectives of the SEM Committee, as referenced in Section 2.1, are:

> … to protect the interests of consumers of electricity in Northern Ireland and Ireland supplied by authorised persons, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the SEM.
>
> Having regard to
>
> (a)the need to secure that all reasonable demands for electricity in Northern Ireland and Ireland are met; and
>
> (b)the need to secure that authorised persons are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity Order or the Energy Order or any corresponding provision of the law of Ireland; and
>
> (c)the need to secure that the functions of the Department, the Authority, the Irish Minister and CER in relation to the SEM are exercised in a co-ordinated manner,
>
> (d)the need to ensure transparent pricing in the SEM;
>
> (e)the need to avoid unfair discrimination between consumers in Northern Ireland and consumers in Ireland.

The policy proposals set out in this documents flow explicitly from these objectives and are designed to better facilitate these objectives. In addition to the objectives of the RAs it is also worth noting the criteria of the market power mitigation strategy as set out in AIP/SEM/02/06. These are:

- Effectiveness
- Feasibility
- Retention of the Profit Motive at the Margin
- Allows for Innovative Strategy
- Regulatory Efficiency
- Flexibility
- Transparency
- Ability to Sunset
- Impact on Retail Markets

These criteria have been borne in mind when framing the proposed changes to the market power mitigation strategy. It is however important to note that we also make policy proposals to promote competition in the SEM.

## 6.2. Assessment of current mitigants

This section provides a summary view on how well the current market power mitigation strategy is working and provides the case for any change.

### 6.2.1. BCoP and MMU

The BCoP and MMU provide substantial protection against the abuse of market power, such that careful consideration needs to be given to precisely what additional protection against the exploitation of market power other measures provide.

### 6.2.2. Directed Contracts

Directed Contracts play a complimentary role in mitigating against the use of market power by reducing incentives for parties to withhold capacity from the market.

There appears to be a residual and reasonable concern about a lack of liquidity in the contract market arising from the presence of market power, notwithstanding that participants would not expect the SEM to be characterised by very high levels of contract market liquidity. Therefore, this issue may best be addressed following the commissioning of the East-West Interconnector by complimenting the Directed Contracts by introducing an alternative liquidity release mechanism. It should further be noted that the Directed Contracts themselves serve as a link to reduce the potential demand for hedges by reducing demand. In order to help facilitate liquidity it would be desirable to also reduce concentration in the wholesale market, to firstly reduce the need for market power mitigation, and secondly increase the demand for hedges by suppliers. This would help stimulate the development of a traded market for contracts.

### 6.2.3. Horizontal ring fencing

It is unclear what additional risks of exploitation of wholesale market power horizontal ring fencing addresses that are not already addressed by the BCoP and MMU. Given the costs of such ring fencing provisions it may be appropriate to remove them in an operational sense, but leaving legal separation in place as this arguably has option value for future structural changes.

Overall we consider that the market power mitigation strategy appear to be serving well and has proven successful in attracting investment. We would caution against substantially reforming the existing measures before the impact of increased interconnection becomes clear and the market arrangements have bedded down.

### 6.3. Structural changes in the SEM

The proposals put forward by ESB to the SEM committee present three main structural options (as the horizontal integration in the retail market is progressing with the transition to full retail market deregulation, subject to any new conditions which the SEMC may deem necessary to address wholesale market power or liquidity issues, vertical integration between ESB CS and ESB PG is not considered as a separate option). These are illustrated in Figure 6.1 below.

*Figure 6.1 Potential structural changes in SEM*

| | | Horizontal integration of ESB groups generation | |
|---|---|---|---|
| | | No | Yes |
| Vertical integration of ESB | No | **Option A:** No further removal of ring-fencing between ESB Group companies: Retains current structure, no horizontal, or vertical integration of ESB Group | **Option B:** Removal of information sharing restrictions between ESB group generation companies i.e. ESB PG, ESBI, and allowing joint trading activities while retaining separate legal corporate form. Ring-fencing of ESB CS retained. |
| | Yes | N/A | **Option C:** Removal of information restrictions and permission to set up joint trading activities for ESB group; i.e. ESB PG, ESBI, ESB CS |

In the following sections we discuss policy options in the context of each of these structural changes. These options are discussed against the backdrop of the forward looking modelling of competition and hedging we have presented in the previous sections. Broadly speaking our policy measures to promote competition can be divided into two categories:

- *Structural measures* – these measures are designed to improve competition in the market by making changes to the industry structure. The main types of structural measures are changes to ownership structures. This includes structural changes to companies, such as the sale of business units or assets. It is also possible to include ring-fencing between business units in this category, although these require a degree of monitoring, which ownership changes typically do not.
- *Behavioural measures* – these are measures that are designed to mitigate against market power by putting restrictions and/or obligations on the behaviour of market participants. Examples of behavioural measures include several of the existing market power mitigation rules such as the BCoP, and directed contracts. Alternative behavioural measures include measures such as voluntary codes of practice and explicit bidding rules.

Structural measures can have several benefits above and beyond behavioural and regulatory measures. In particular they directly influence the competitive situation in a market, and require less direct monitoring.

## 6.4. No removal of ring-fencing between ESB Group companies

In this section we discuss policy options appropriate if the ring fencing of ESB Group companies is retained, both in terms of horizontal and vertical integration.

### 6.4.1. Summary of outlook for competition and liquidity

Not surprisingly, this structural scenario produces the most favourable structure in terms of market power metrics and suggests least concern is warranted from a market power perspective of the three cases. In this case the market structure will continue to become less concentrated and the potential for future relaxations to the market power mitigation measures to enhance competition is arguably greater. Table 6.1 summaries the outlook for the market power metrics.

*Table 6 .1 Market power metrics in SEM – no removal of ring fencing*

| | **2015** | **2020** |
|---|---|---|
| Market share of ESB PG (by output) range of minimum and maximum across scenarios | 15%-29% | 12-24% |
| Wholesale Market concentration (HHI) by output (before deduction of volumes under Directed Contracts) | 1073-1614 | 784-1468 |
| Wholesale Market concentration (HHI) by capacity (before deduction of volumes under Directed | 1481 | 1144 |

| | | |
|---|---|---|
| Contracts) | | |
| % of half-hours with RSI below 1.1 for ESB PG | 1% - 4% | 1%-7% |

In the following sections we outline the options for reforming the market power mitigation strategy, improving competition and improving liquidity and the availability of hedging contracts.

### 6.4.2. Options for reforming market power mitigation strategy

Under this structure the current market power mitigation strategy based on the BCoP, market monitoring through the MMU and forced contracting, continues to be fit for purpose with two minor modifications:

- We agree with some market participants that that there may be a case for increased transparency in the operation of the MMU, including its investigations and reporting. Increased transparency would help provide certainty to the market[43].
- There may be a case for reforming Directed Contracts to a form where they are allocated to parties based on willingness to pay, or ex-post based on actual consumer numbers rather than as currently made available to market participants based on a demand profile. This will mitigate against the potential effect of Directed Contracts of raising barriers to entry in the Retail Market.

Under this scenario the need for market power mitigation will gradually diminish both as a result of continuing entry in the wholesale market and it may be prudent to review the market power mitigation strategy again after the market has developed experience of the operation the East West interconnector.

### 6.4.3. Options for improving competition

In this section we discuss further options appropriate for this scenario – in particular how further reducing market concentration can enhance competition. Enhancing competition in the SEM would enable competitive pressures to take the place of certain regulatory measures, such as relaxation of the BCoP.

In order to achieve greater competition in the SEM it could be desirable to reduce the size of some of the existing parties, and in order to facilitate the emergence of greater contract liquidity, also ensure that the assets considered constitute an appropriate portfolio. Finally the interests of the residual firms also need to be considered.

The three largest generators in the SEM in 2015 by output under this scenario are ESB PG, AES and ESBI as illustrated in Table 6.2. Under this scenario concentration decreases over time compared to current levels (and as Table 6.1. suggests even further by 2020).

*Table 6 .2 Market power metrics in SEM (by output) – no removal of ring fencing, NewGenco*

[43] We note that the Regulatory Authorities are intending to consult on a process manual for the Market Monitoring Unit

| | Installed capacity (no change) | 2015 market shares (no change) high coal / low coal (medium GB gas price) | Installed capacity (with NewGenco) | 2015 market shares (with NewGenco) high coal / low coal (medium GB gas price) |
|---|---|---|---|---|
| ESB PG | 3268 MW | 15% / 28% | 2791 MW | 14% / 27% |
| ESBI | 1207 MW | 16% / 11% | 1207 MW | 16% / 11% |
| AES | 1830 MW | 6% / 12% | 1830 MW | 6% / 12% |
| Bord Gais | 734 MW | 6% / 2% | 734 MW | 6% / 2% |
| Viridian | 740 MW | 5% / 1% | 740 MW | 5% / 1% |
| Endesa | 876 MW | 8% / 7% | 876 MW | 8% / 7% |
| NewGenco | 0 | 0% / 0% | 475 MW | 1% / 0% |

In order to reduce concentration in the SEM we considered a scenario, for illustrative purposes only, where the largest generators by installed capacity, ESB PG was required to divest the Poolbeg station into a new generating company (NewGenco). As indicated in Table 6.2 this has a dramatic effect on market shares as measured by output. As table 6.3 suggests it would also have a dramatic effect on reducing the HHI in the market.

*Table 6.3 Market power metrics in SEM no removal of ring fencing, NewGenco*

| | No structural change (high coal / low coal) (in brackets is figures for high GB prices) | With Newgenco (high coal / low coal) |
|---|---|---|
| % of half-hours with RSI below 1.1 for ESB PG | 1% (4%) | 0% (2%) |
| HHI (before deduction of volumes under Directed Contracts) | 1349 | 1129 |

In term of RSI the scenarios with low demand growth and GB parity in prices, the analysis does not indicate a non-competitive outcome would be likely before the measure is in place. The measure however significantly reduces the HHI.

### 6.4.4. Options for improving liquidity and availability of hedges

Currently ESB PG provides the majority of hedging contracts in the SEM through the Directed and Non-Directed contracts. As discussed earlier, the volume of Directed Contracts to be offered is however dependent on the amount of wholesale market power and the Non-Directed

Contracts are provided on a voluntary basis, thereby both reducing the exposure of downstream parties to volatility in the SMP price, and providing the ability to compete with ESB CS for forward market volumes to facilitate further expansion.

It is however not reasonable to expect ESB to continue to support the market with liquidity on an ongoing basis if the wholesale market power metrics was to reduce and the market become more competitive. Fundamentally ESB's special responsibility for aiding the development of competition in the market through providing hedging products should, as it is now, be proportional to its market power position. As discussed in earlier chapters market power is not a binary question, but rather one of degrees and it would be reasonable for ESB's obligations to provide liquidity to continue to be linked to a market power metric. If contract market liquidity fails to develop as the market power of ESB reduces then the lack of liquidity needs to be recognised as an issue of interest to all market participants.

In order to promote competition and to facilitate the development of traded market liquidity transparency is a key factor. In order to increase the likelihood of the SEM appearing attractive to trade on a financial basis, the price formation mechanism needs to be seen as sound and transparent. It is also important that there are no significant information advantages available to incumbents. While the SEM arguably has good information available to market participants, the RAs and Market Operator should be vigilant to ensure this remains the case.

A potential limited intervention that could have an important impact on market confidence would be a transparency programme for market data such as outlined in Section 5 of this document. This could include various items from a requirement for all parties to make certain categories of information available, to a more gradual approach led by the regulator. Market participants have highlighted that some market features could require additional explanation, or for data to be published such as:

- Transmission outages and constraint treatment;
- Investigation and reporting by the MMU; and
- Forecast future DC/NDC volumes.

As a starting point additional information on these items may be beneficial.

If lack of access to hedges is considered a significant impediment to competition in SEM by market participants, in particular ones active in the downstream market, then there may be case for adopting a specific policy to ensure minimum levels of hedging contracts are made available. The potential objectives of such a policy are outlined in Box 6.1.

*Box 6.1 potential objectives for a liquidity policy*

| Objectives for a liquidity policy |
| --- |
| A measure designed to promote competition by ensuring a minimum availability of hedges in the SEM should:<br><br>• Link the overall impact of the measure to: |

- overall competition in the market
- overall liquidity in the market

- The measure should not be unduly discriminatory
- It should provides a predictable amount of hedging contracts:
    - obligated to be provided by parties more likely to have market power, but declining as competition continues to develop;
    - the hedging contracts should be offered on a non-discriminatory basis; and
    - they should be  based on a market price, preferably without a reserve price.
    - that minimises the risk of market power being exploited in the forward market
- The measure should not discourages the emergence of generic trading; and should sunset when generic trading emerges

A policy designed to provide a minimum level of contracting to the market under these principles could take several shapes and multiple specific measures are possible. In principle, however, several options could be considered:

*Option 1: a minimum volume* provided by a mix of market power based and market based contracts

- a measure linked to wholesale market power could be similar to the current Directed Contracts. In its current form the Directed Contracts, while mitigating against wholesale market power, however do not promote downstream competition and may serve to discourage entry downstream. In order for it to facilitate market entry it would however be necessary to reform the DC's to:
    - o be allocated based on mechanism whereby entrants have an equal opportunity to obtain the Directed Contracts, such as a market mechanism;
    - o be offered through a mix of the current eligibility mechanism and a market mechanism; and
    - o reallocate the DC volumes on an ex-post basis to parties based on their actual achieved market share (rather than the ex-ante market share).[44]
- if competition reduces the availability of hedges provided through the market power linked measure below acceptable levels, then market participants would be obliged to offer contracts to the market up to the same volume based on their relative market shares.

For contracts offered on a market basis two main options exists:

- an auction system; or
- bilateral trading (backed up by an auction with a reserve price of zero).

[44] We note that this arrangement would be somewhat cumbersome, although the arrangement is not dissimilar to French gas storage contracts which are based on incumbent market share.

Both of these have advantages and disadvantages. Allowing bilateral trading backed up by a fixed date reserve price auction may provide incentives for the party offering contracts to actively market their contracts and to engage with potential customers to maximise the value of their products. A drawback of the system may however be that if there are insufficient competition among the buyers it could expose the seller to buyer market power, or buyer collusion forcing it to sell volumes at the reserve price action.

The measure would be calibrated to sunset if real traded volumes were to emerge. For example it may be appropriate for the scheme to be re-evaluated every 3-5 years, or in light of substantial market events. In particular such a scheme may not be necessary if the East West interconnector facilitates trading.

*Option 2: a market maker*

Another option could be for a market maker to be appointed in the SEM. Market makers have notably been successful in achieving liquidity in the Nordpool market. It is however important to note that in Nordpool generators volunteered to undertake this service as an investment to provide price discovery and liquidity in the market (form which they ultimately would benefit).

A market maker in the SEM would agree to provide a minimum level of liquidity to an exchange and post bids and offers with a maximum spread. In practice this could be adopted in two ways:

- The largest generator (or potentially 3 largest generators) could be mandated to undertake the role of market makers.
- The RAs could tender for a "minimum specification" market maker. The specification of such a market maker would be developed through a consultation process with in particular smaller suppliers, but also industry in general. The tender evaluation could be based on what level of cover the market maker would need for his risk to be able to undertake the "minimum spec" market maker role. Under this options it would be envisaged that usage of the system would be limited to suppliers of a certain size for the volumes provided on a regulated basis.

Similar to Option 1 the measure could be reviewed regularly to determine if it remained fit for purpose or needed.

Under either of these options the market maker would also be required to make the platform available for use by other parties. The market maker approach helps above and beyond simple buy/sell auctions in that it also helps against the potential manipulation by means of setting reservation prices. This is due to the fact that a party is required to remain within a maximum spread between bids and offers. If the party post a too high bid or offer, then he would also be required to buy/sell electricity at the implied opposite price.

### 6.4.5. CEPA's assessment

The main argument for retaining the present structure with some of the suggested improvements is that competition in the SEM is on course to deliver continued benefits over the next 10 years. Given the impending East-West interconnector and possible subsequent market coupling, the market is likely to continue to change considerably in the next few years. Given this, it is likely to be prudent to pause before allowing the vertical integration of ESB Group. Nevertheless against that, the costs of horizontal separation seem burdensome, and the risks of allowing the ESB generating companies to share and exchange information and possibly share a joint trading arm seem small, providing the BCoP remains in place. This is balanced with the fact that doing so would reduce the ability of the market power mitigation strategy to be relaxed or removed. This could however have implications for the incentive to trade as it would reduce the number of active parties in the market. On balance we consider these gains might be worth the possibly small additional risk, but we consider that retaining separate legal corporate forms has an option value that is likely greater than the benefits of full integration. Furthermore, under this scenario ESB CS will have a strong incentive to encourage ESB PG to provide a greater range of contract products.

## 6.5. Horizontal ring-fencing between ESB Group generating companies relaxed or removed

In this section we discussion policy options appropriate if the horizontal ring fencing of ESB Groups generating companies is either relaxed or removed altogether.

### 6.5.1. Summary of outlook for competition and liquidity

Full horizontal integration of ESB Group's generating companies in this context means the integration of the stations under ESB PG and ESBI and Synergen. An intermediate step (partial horizontal integration) would allow the ESB generating companies to share and exchange information and share a joint trading arm. Full integration would add the Dublin Bay and Coolkeeragh power stations to ESB's portfolio of conventional generating assets, as well as the wind portfolio of Hibernian Energy. Full integration implies a significant increase in concentration of baseload generation as it would concentrate the control of the modern and effective CCGT baseload plants of Coolkeeragh, Dublin Bay and Aghada to a single party (as well as the Moneypoint coal station). Together the CCGT plant consists of 1,220MW of generating capacity in the context of 4.5 GW of ESB Group. The combined output of these three station would, depending on relative coal and gas prices be between 8.4 and 5.9TWh in 2015 (if coal is in merit then Moneypoint would add another 6.2 TWh to the 5.9TWh). This means that ESB will have:

- a significant proportion of generation with installed capacity of 38% against the second largest generator (AES with 16%) of installed capacity in the market;
- a significant proportion of output varying between 21% and 39% in 2015; and
- a large proportion of the spare capacity in the market.

It is nevertheless important to note that the entry of new capacity over the period, notably the Bord Gais Whitegate CCGT, will help enhance competition. Based on forward looking modelling undertaken by the RA's we expect the market power metrics for this scenario to develop as outlined in Table 6.4.

*Table 6.4 Market Power metrics in SEM – removal of horizontal ringfencing*

| | 2015 | 2020 |
|---|---|---|
| Market share of ESB by output, range of minimum and maximum across scenarios | 31-39% | 18-34% |
| Wholesale Market concentration (HHI) (exclusive of Directed Contracts) | 1873 | 750-1732 |
| % of half-hours with RSI below 1.1 for ESB Group | 4%-24% | 6%-25% |

On balance this indicates that wholesale market concentration is likely to remain at material levels under this scenario and therefore measures to enhance competition will need to be explored further. It is further important to note that in this market context concentration will initially increase due to the integration of ESB's assets, but may then gradually decline. It is however uncertain to what extent investment in conventional capacity will necessarily continue as wind power becomes more predominant in the market.

Allowing the horizontal integration of ESB's power generation arms has the benefits of enabling ESB to remove duplication of functions, and thereby reducing its costs. This includes information sharing and duplication of trading functions.

In the subsequent sections we discuss what this market context implies for reforming the market power mitigation strategy and for policy options to enhance market power and liquidity.

### 6.5.2. Options for reforming market power mitigation strategy

Absent the market power mitigation strategy, the horizontal integration of ESB has potential implications for the underlying competitive structure of the wholesale power market. We would expect that this structural change would mean that increasing regulatory intervention may be necessary. Several options are available to increase the impact of the current market power mitigation strategy such as:

- A stricter bidding rule regime (such as more explicit bidding formulas, or formulas approved ex-ante by the regulatory authorities).
- Increase the volume of Directed Contract to be offered. This could be done by lowering the overall threshold for the calculation from the current HHI of 1150 to a lower number. A similar approach change could also be adopted for an alternative measure.

In our assessment the market power mitigation strategy under this scenario will remain relatively effective for two reasons:

- the BCoP is likely to make it very difficult for parties to exploit market power;
- the volume of directed contracts is directly linked to a measure of market concentration in the generation market. The re-integration of ESB's generation portfolio will cause the

concentration measure to increase sharply (at least in the short term), and therefore increase the total volume of Directed Contracts it is required to provide. This further limits the ability of ESB to exploit any market power arising from its position.

Under this scenario it is assumed that ESB CS remains a ring-fenced company while competition continues to deepen in the retail sector. The separation of retail supply arm from the generation arm further helps ensure that ESB CS will need to continue to innovate its contractual strategy to compete. This has the impact of presenting opportunities for entry in the market for forward market contracts, and may also help reduce any market power in the contracts market. As already noted, the EPO has been removed from ESB CS for industrial and commercial, coincident with the cessation of retail price regulation from the 1st October, and CER intends that it will be removed for ESB CS domestic customers once the criteria are met for this market, although this removal may be conditional on other measures being in place.

#### 6.5.3. Options for improving competition

The increased concentration in the wholesale market under this scenario presents a challenge for identifying measures to enhance competition. In particular, it is notable that the structural measures to ensure competitive conditions are satisfactory under this structure would be tantamount to reverting the structure to its original form. Given this we do not discuss specific measures in this section.

It is nevertheless the case that the competitive situation in the SEM may change following the introduction of the East-West interconnection, if the market rules are also changed to allow for effective competition from the GB BETTA market. Such competition would potentially reduce the ability of an integrated ESB group to exploit wholesale market power. It is, however, notable that market arrangements for Moyle suggest that changes are needed to facilitate effective flows across these interconnectors and developing such changes could take a period to be developed.[45] Ensuring effective cross-border trading is facilitated and third party access is made available on an effective basis might enhance competition sufficiently for the market power mitigation strategy to be reviewed under this scenario. It should however be noted that it would be preferable for the SEM and its market participants to have a period of experience of the interconnector regime before the mitigation strategy is reviewed.

#### 6.5.4. Options for improving liquidity and availability of hedges

Under this structural change we would expect the overall impact on baseline liquidity to be limited for two reasons:

- ESB CS will still have a significant demand for hedging contracts which will both serve as an opportunity for generators to provide hedging contracts, and ensure a level playing field against a supplier which sources it energy either from contracts, or from the GB wholesale power market.

[45] It may be that the current system in which the spot price is only finalized after 4 days needs revisiting with a firm predictive ex ante price. Some changes may be needed in any case if there is market coupling with BETTA.

- The total volume of Directed Contracts available will increase as a result of the increase in the short term as a result of concentration in generation.

Under this scenario we consider the potential problem of market power in contract markets to be relatively limited as both the integrated ESB generation business and ESB CS would have an incentive to develop products and processes to ensure they could compete with integrated competitors (or competitors sourcing power from the GB wholesale market over the interconnectors)).

Similarly to the scenario with no structural change we would however note that the requirements on market participants to provide products should be proportional to their potential market power. For ESB the horizontal integration would mean initially this obligation to provide products to the market would increase however over time it may once again be reduced. Overall we would expect the appropriate measures to increase liquidity to be similar under this scenario to the no structural change scenario: i.e:

- an initiative to ensure transparency and better information in the market
- a measure providing hedges through either
    - a combination of a market power linked measure and one which all generators are subject to; or
    - a market maker.

We would however note that the impact of the market power linked measures would have a greater impact given the greater market share of the horizontally integrated ESB.

#### 6.5.5. CEPA's assessment

While there are clear advantages in retaining separate legal ownership of generation companies if at some stage there might be divestiture leading to less concentrated ownership, the present restrictions on information sharing and trading impose costs on the ESB generating companies that do not seem compensated by the market power mitigation they offer, so long as the other market power mitigation measures (BCoP, MMU) remain effective.

### 6.6. Horizontal and vertical integration of ESB allowed

In this section we discussion policy options appropriate if the horizontal and vertical ring fencing of ESB Group's companies is removed.

#### 6.6.1. Summary of outlook for competition and liquidity

Under this market structure ESB would vertically and horizontally integrate. Under this option ESB CS consumer portfolio would be backed by the generation assets currently available to ESB PG and ESBI.

Another key difference is the impact on retail market power.

- ESB's generation capacity would provide an automatic and costless hedge for its retail activity, reducing or eliminating its need to trade contracts with other market participants unless this were mandated.
- Vertical integration would, absent undertakings, give ESB the power to deny other suppliers forward market wholesale market access unless prevented.
- ESB's liquidity proposals, in the context of an integrated company, are helpful, but at best they would mitigate a power that ESB does not currently hold due to the ring-fencing.
- Even if vertical integration were approved, together with certain liquidity requirements (on ESB and potentially other generators), this would not address the underlying lack of incentive on ESB to engage actively with market participants to offer liquidity of the right shape etc and increase reliance on the regulators to monitor, approve and track the type of contracts made available is what potential entrants need. It would also give potential entrants subsequent pause to consider whether, after they entered, they might be subject to various forms of hard-to-monitor discrimination.
- Whilst intermediaries may emerge to assist new entrant suppliers to access liquidity, this is far from certain, and the evidence of the rapid exit of new retail players in the GB market post 1998 is not encouraging. It should further be noted that the total potential market served by such parties will be significantly smaller compared to the current situation as:
    - An integrated ESB would have less of an incentive to facilitate trading (as this could potentially aid new entrant by reducing entry barriers)
    - The increase in horizontal concentration implied volumes of Directed Contracts of between 0.03 and 3.4 TWh / year (net of ESB own entitlement), this will effectively reduce the potential demand for hedges by up to 20% of the residual demand (assuming ESB groups share of total demand remains at around 40% as indicated in the State of the Nation report[46].)
- Hence if vertical integration were to be approved, there would need to be a review of the nature of tariff regulation in retail markets that are not considered competitive.

### 6.6.2. Options for reforming market power mitigation strategy

Under the scenario we see both increased concentration in the wholesale generation market, and a combination between the largest players in both the retail supply of electricity and generation into a single dominant vertically integrated incumbent. It is important to note from the outset that under this structure one of the market power mitigation measures - the vertical ring-fencing between ESB CS and ESB's generating arms - is removed.

It is further worth noting that under these conditions the market power mitigation strategy through the Directed Contracts ensures that the RSI stays above 1.1 for more than 95% of periods in most scenarios. In order to ensure that the RSI remains above 1.1 for more than 95% of period across the scenarios the volume of DCs would need to be increased.

[46] SEM – 10 – 057, page 40, Figure 26

On balance we consider that while the market power mitigation strategy could be expanded by introducing additional behavioural and/or regulatory measures, it would be difficult to address the removal of an important structural remedy by using behavioural measures alone. We do however understand that ESB could realise some efficiency saving by being allowed to operate as a vertically integrated company, but these unproven savings might be more than offset by less efficient purchasing of power.[47] In the following section we consider potential structural remedies which could allow the benefits of vertical integration to be realised, while at the same time promoting competition in the SEM.

### 6.6.3. Options for improving competition

In this section we discuss potential structural options improve competition and liquidity with the horizontal and vertical integration of ESB group as a starting point.

As outlined in earlier in this section, the competitive starting point under this scenario is significantly worse, both in terms of market concentration, and RSIs compared to the structural scenario where ESB is retained in its present subdivisions. In addition to this the vertical integration of ESB presents additional challenges. In it sector enquiry the European Commission identified some of the general issues with vertical integration in electricity markets:

> "Vertical integration of generation and retail reduces the incentives to trade on wholesale markets. This might lead to a drying up of wholesale markets. Illiquid wholesale markets are a barrier to entry as they are characterised by higher price volatility. Volatile wholesale markets might oblige new entrants to enter as a vertically integrated generator and supplier, which is more difficult"[48]

In order to achieve greater competition, and to mitigate against the likely negative impact on liquidity in the SEM, a potential structural option would be to create an independent market participant with a suitable portfolio to maximise its potential ability to offer forward products to the market. In addition to this it would be desirable to ensure that the party would provide a potential incentive for retail suppliers who wish to contract with it.

Desirable properties of such as party would be for its structure to include:

- Low merit order gas fired generation;
- Coal generation based to ensure the party benefits from a portfolio effect in offering Contracts for Differences
- Potential additional mid merit generation if it helps reduce the risk of offering contracts and reduces market concentration.

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[47] Triebs, Pollitt and Kwoka (2010) ` The Direct Costs and Benefits of US Electric Utility Divestitures' EPRG1024 found that vertical unbundling of US utilities increased overall efficiency, and although retailing costs appear to have risen, the saving on buying power more competitively was far greater than the apparent increase in these costs, suggesting that they were more an accounting change of cost allocation than a real cost increase.

[48] Final Report of the European Commission Energy Sector Enquiry, http://ec.europa.eu/comm/competition/sectors/energy/inquiry/full_report_part2.pdf; p128 and p. 169

The party would not have a retail position (but may possibly be allowed to enter the retail market after a period of time). Instead it would act as an independent producer, with access to both low merit order gas, and coal fired generation. Based on this portfolio, there would be an incentive for suppliers in the market to seek to contract with the party.

In order to investigate the competitive effect of modifying the industrial structure to introduce another party of this type we consider an entirely hypothetical scenario where the Moneypoint and Dublin Bay plants from the vertically and horizontally integrated ESB group are placed in a separate generating company (NewGenco).

Table 6.5 provides the higher level overview of the market characteristics of such a company

*Table 6 .5 Market power metrics in SEM (by output) –removal of horizontal and vertical ring fencing, NewGenco*

| | **Installed capacity (no change)** | **2015 market shares (no change) high coal / low coal (medium GB gas price)** | **Installed capacity (with NewGenco)** | **2015 market shares (with NewGenco) high coal / low coal (medium GB gas price)** |
|---|---|---|---|---|
| ESB Group | 4475 MW | 32% / 39% | 3225 MW | 25% / 19% |
| AES | 1830 MW | 6% / 12% | 1830 MW | 6% / 12% |
| Bord Gais | 734 MW | 6% / 2% | 734 MW | 6% / 2% |
| Viridian | 740 MW | 5% / 1% | 740 MW | 5% / 1% |
| Endesa | 876 MW | 8% / 7% | 876 MW | 8% / 7% |
| NewGenco | 0 | 0% / 0% | 1250 MW | 7% / 20% |

As indicated in Table 6.5, not surprisingly, this has a dramatic effect on market shares as measured by output, both when coal is in merit and when it is not. As Table 6.6 suggests it would have a dramatic effect on reducing the HHI and RSI in the market to competitive levels.

*Table 6 .6 Market power metrics in SEM integration and NewGenco*

| | **Vertical and horizontal integration (high coal / low coal) (in brackets is figures for high GB prices)** | **With NewGenco (high coal / low coal)** |
|---|---|---|
| % of half hours with RSI below 1.1 for ESB Group | 5% (24%) | 0% (3%) |

| | | |
|---|---|---|
| HHI | 1873 | 1161 |

The portfolio effect of the Moneypoint coal station and the Dublin Bay CCGT station provides a potentially important combination in providing between 7 – 19% of output on a non-integrated basis. NewGenco would also have a structure similar to that of AES's capacity in the SEM, which should induce competition between these parties. The volume of these parties would furthermore be available to other parties to contract (with the additional protection of competition law to protect against potential attempts to foreclose the market from the buyer side).

Under this condition the generation arm of ESB Group would be reduced in size and may put the new combined entity out of balance with its consumer demand. The entity would however still possess significant capacity in the form of CCGTs and peaking plant which means that it would have access to a substantial internal hedging capability. It would however still be subject to the competitive pressure which would occur if coal was to become an in-merit fuel. Under these circumstances ESB would need to procure hedges from NewGenco or AES on the same basis as other suppliers. If it choose not to do so it would then run the risk of other suppliers being able to obtain better hedging conditions.

The experience of the GB and other retail market suggest that competition concerns can arise in retail market even in the context of multiple competitors. In particular retail energy markets tend to have the following characteristics:

- churn levels proportional to discounts offered relative to competitors;
- a substantial proportion of consumers can be "sticky", i.e. will not switch even if offered a substantial discount; and suppliers can easily price differentiate between different categories of users.

A further theoretical option could be a structural remedy to reduce ESB's market share in both retail supply and generation. Creating two ring-fenced entities could allow each one to realise some of the benefits of vertical integration, while at the same time also promoting competition between the two entities. It would also be desirable for a degree of at least reporting and accounting separation to be maintained between each of the retail and generation arms. This will enable transparent monitoring of potential cross-subsidisation between generation and retail arms.

A further measure which could serve to increase competition in this scenario could be to undertake a facilitated one-off retail market "active choice". Under such a campaign each supplier would be require to present former ESB consumers with an explicit choice of offers. The RAs would then collate the offers which could be sent by mail to each household. The two vertically integrated and ring-fenced entities would each be allowed to participate along with any other supplier. If a consumer was to decline making an active choice, then it would default to one of the supply companies by way of lottery, but receive the contractual conditions and prices offered through the campaign by defaults. Undertaking such an exercise could potentially limit the ability of incumbent suppliers to take advantage of the stickiness of some consumer groups.

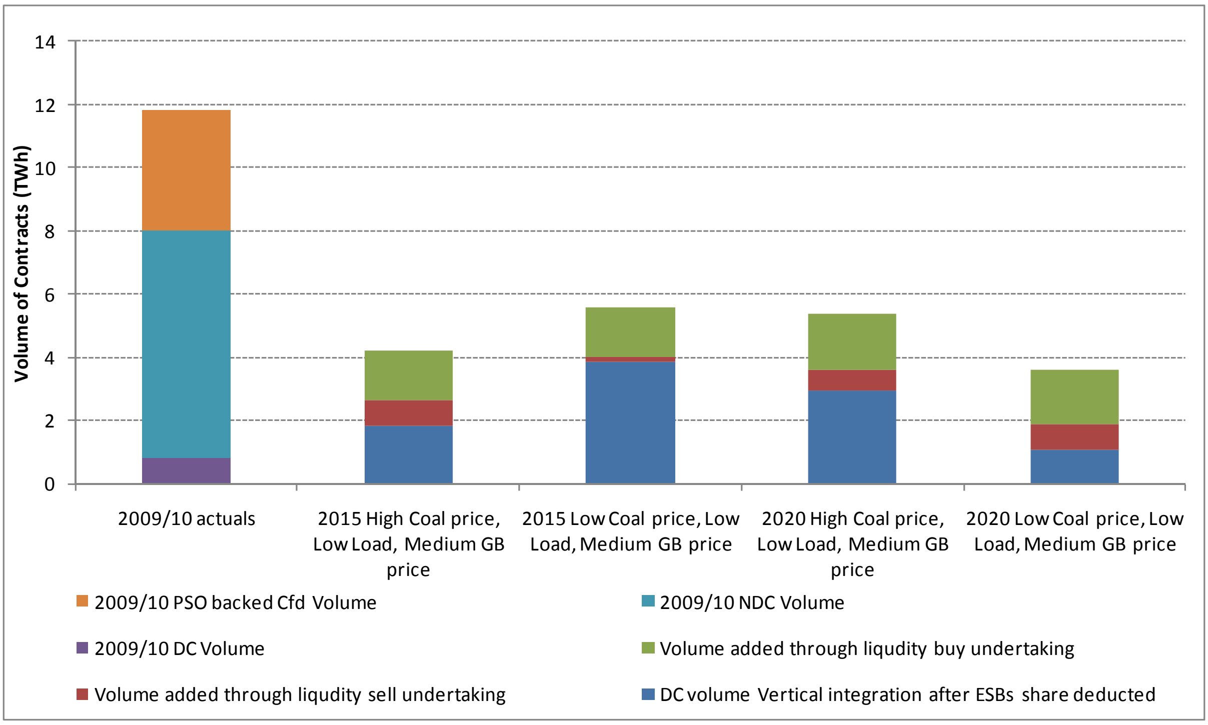
Creating two ring fenced entities would have the additional benefit of providing flexibility for the SEM to potentially moderate the market power mitigation strategy further to, for example, ensure better compatibility with the BETTA market, which would further facilitate both competition and liquidity. In addition to this it would keep the option open to allow the two companies to potentially re-integrate if effective regional Ireland-Northern Ireland-GB markets develop for retail and wholesale power through entry and market integration.

### 6.6.4. Options for improving liquidity and availability of hedges

The provision of liquidity and hedges in the SEM under the vertically and horizontally integrated structure is problematic. As discussed elsewhere the volume of Directed Contracts would be likely to increase in the short term as a result of increased market concentration arising from the integration between ESB PG and ESBI. It is however possible that the Non-Directed Contract volumes will diminish sharply and the Directed Contracts would make up a significant proportion of the volumes offered by ESB to the market. It is also notable that the single biggest source of demand for Non-Directed Contracts - ESB CS - will have a lower requirement for contracts.

Figure 6.2 shows the potential impact on overall volumes of contracts available to the market in comparison to actual 2009/10 contract availability. The columns show the volume of DC's and release mechanism NDC's ESB would be making available to the market under its proposed liquidity undertaking. The figure only counts the DC volumes ESB itself would not be eligible to take up towards ESB's liquidity commitment.

*Figure 6.2 Actual 2009/10 volumes and estimated volumes of Directed Contracts and liquidity buy and sell volumes for 2015 and 2020 Low demand scenarios*




As can be seen the overall volume is likely to reduce sharply. It is however important to note that at the moment limited trading means that this may still not have any effect on price discovery.

Combined with a potential removal of the PSO levy back CfD's it could however squeeze the availability of hedges.

### 6.6.5. CEPA's assessment

Our overall assessment of the option of relying on behavioural remedies (by enhancing the market power mitigation strategy) to allow the vertical re-integration of ESB Group is unfavourable as doing so would replace a structural remedy with a likely less effective behavioural and/or regulatory remedy. The whole thrust of EU liberalization has been to unbundle generation first from transmission and then from distribution, with some pressure for further separation of distribution and retailing. In addition to this we note that the market power mitigation strategy does indeed potentially protect consumers against the potential horizontal effects. Allowing re-integration would come at the expense of reducing any scope for encouraging competition by reducing the scope of the market power mitigation strategy.

In addition to this it should also be kept in mind that potential investors investing in generating capacity in Ireland in anticipation of future de-regulation may not look favourable upon the re-integration of the incumbent. Vertical separation is seen as a fundamentally positive feature to encourage the development of liquidity in the market. In addition to this additional behavioural remedies will be perceived as greater regulatory risk. Parties examining the SEM as a potential investment candidate may consider that allowing vertical integration would increase the level of risk of operating in the market, and ultimately reduce the level of entry and investment in the market.

The regulators have an important role in signalling commitment to the development of competition. But of course a preferable option under these conditions would be to balance the re-integration of ESB Group with significant structural divestment (into separate ownership) to help facilitate the development of liquidity and wholesale market competition. In this regard we understand that the Irish Minister for Finance has appointed "The Review Group on State Assets and Liabilities" to consider, inter alia, the potential for asset disposal in the Public Sector including commercial State Sponsored Bodies.

## Annex 1: Summary of responses to State of the Nation Review

In this Annex we provide a summary of the key issues raised by the stakeholders who have responded to the joint Commission for Energy Regulation and Northern Ireland Authority Utility Regulation (NIAUR) consultation on: the Single Energy Market (SEM) Power & Liquidity, State of the Nation Review.

In Table A1 below we summarise the stakeholders responses to each of the questions stated in Section 2.3 of the consultation document. In addition we summarise the additional issues raised by the stakeholders that do not directly respond to the specific consultation questions.

*Table A1: Summary of consultation responses*

| | Consultation question | Response | Source |
|---|---|---|---|
| **1** | How well are the market rules and monitoring arrangements working in terms of promoting contract liquidity, competition and market entry? | The market rules do not promote liquidity. Liquidity is provided through the regulator directed CfDs Directed Contracts (DCs), which have been complemented by the offering of some Non-Directed Contracts (NDCs).<br><br>BG are of the view that market liquidity could be manipulated without the introduction of rules to enshrine liquidity in the market. They suggest that a greater proportion of auctions should be offered through DCs rather than NDCs to provide greater certainty. | Bord Gais |
| | | Viridian are of the view that the existing approach to determining both the price and quantity of the DCs is not transparent. Further the available range of DCs is inappropriate and misaligned with the needs of market participants. The current set-up reduces liquidity and competition in the market as the contracts favour domestic suppliers, which can deter market entry.<br><br>Alternative options for DCs should be considered such as mandating the quantity of the DCs and auctioning the quantity to determine a market value. In addition a Mid-Merit 2 product is required so that the overall quantity of DCs available should remain at the current level.<br><br>They are of the view that there is a discrepancy between the stated views of the regulators and the actions of the SEM Committee. In their opinion this creates regulatory uncertainty, which restricts market access.<br><br>Viridian state that the Market Monitoring Unit has acted in a way that is reactive rather than proactive, in particular they note that the Unit is too reliant on generators raising complaints. They also state that the Unit should reduce its remit to increase its ability to act proactively on monitoring issues. | Viridian |
| | | ESB are of the view that existing regulatory controls have been very successful in ensuring the smooth operation of the market to date.<br><br>ESB state that the Market Monitoring Unit should include commentary on the effectiveness of the Bidding Code of Practice (BCOP), and include confirmation on the level of compliance of market participants with this regulatory control. | ESB |

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| | | Airtricity recapped its views from its response to the SEMC consultation paper on Market Power Mitigation in the SEM: Directed Contract Implementation Report 2010 (SEM-10-005), dated 12th March 2010. These were that there are issues with the delay between contract execution and delivery; the granularity of products, as well as the improper sizing of subscription windows; lack of standardized terms; lack of general guidelines to inform the conduct of voluntary contracting by the incumbents; lack of recognition of rapidly changing aggregate demand positions of suppliers in the market in determining volume eligibility; limitations on flexibility that can be exercised by suppliers by imposing daily subscription caps and requirements to fully subscribe to allocated quantities for eligibility in subsequent rounds.<br>Regarding market monitoring arrangements, Airtricity have expressed the view that a suitably experienced body, independent of the RAs should carry out the role. | Airtricity |
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| **2** | Do SEM participants have the potential to exercise market power in the short and longer run? Please provide any evidence available. | Believes that in theory there is potential for SEM participants to exercise market power, but in practice the incentives to do so have been removed by the regulators use of tools such as Directed Contracts and market monitoring arrangements.<br><br>State that given the potential for market power, the issue is worth considering. | Endesa Ireland |

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| | | The combination of a Bidding Code of Practice (BCoP) and the Directed Contracts (DCs) reduce the scope to exercise market power in the SEM. Further the operation of the Market Monitoring Unit provides ongoing assessment of compliance against the BCoP.<br><br>Synergen's modelling of electricity market prices does not indicate that market power is being exercised.<br><br>They state that regardless of the BCoP there is sufficient competition in some market segments to provide sufficient consumer protection through competitive pressures. Further the single-site nature of many of the participants makes the exercise of market power through strategies such as economic withholding unlikely in many instances.<br>They also do not believe that there is any evidence of predatory pricing in the market.<br><br>Their initial assessment is that the longer term exercise of market power to raise or lower SMPs has not occurred.<br><br>In terms of the short-term use of market power, they are of the view that it is likely to be constraint related. They are unable to comment whether constrained on/off plant has sought to make short terms changes to bids to exploit its position on the system. They also note that the market monitoring unit should be mindful as to the market definition being applied to any investigation of market abuse. | Synergen |
| | | Regulators initiatives to dilute market power in a nascent SEM have been relatively effective. Though this has focused on efforts to limit the ability of dominant incumbents to hoard generation capacity. In the long-term initiatives should focus on facilitating and incentivising liquidity, ensuring contact prices are set by the market, and allowing the market to emerge such that no one/two parties control the market for liquidity and risk management. | Bord Gais |
| | | Viridian is of the view that there is significant potential for ESB PG to exercise market power, they derive this power largely from the prevailing regulatory arrangements.<br><br>They state that ring-fencing remains to limit the incentives for ESB's market power to be leveraged. | Virdian |

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| | | ESB contend that the key determinant of participants to exert market power is the application and monitoring of the BCOP, as this ensures that the wholesale markets settles based on the SRMC of the marginal plant on the system.<br><br>They are of the view that the control is working as evidenced by the high levels of retail market customer churn experienced in recent years.<br><br>The ESB caution against the use of any single metric to assess the level of market power, and states that a detailed assessment would be required to explain why a particular metric was used. | ESB |
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| **3** | Do market participants face contract liquidity constraints? If so, how are these exhibited, what is their impact, and how could these impacts be addressed? | Agree that market participants (MPs) face liquidity constraints, would like to see the development of a short-term contracts market to facilitate customer switching and more efficient interconnector trading – at present the Directed Contracts (DCs) and Non-Directed Contracts (NDCs) market is only offered over a short window once a year.<br><br>State that the impact of the CfD credit cover arrangements on liquidity in the contracts market should be examined by the regulators. | Endesa Ireland |
| | | Constraints exist around: the price set for contracts; when they are available; how much notice is given to participants on their availability, and how reliable they actually are. Generator User Agreements (GUAs) and the dominance of incumbent integrated utilities inhibit the ability of parties to strike bi-lateral hedge contracts in the market. BG would support the termination of GUAs and other such obligations/agreements that prevent the market from pricing and negotiating liquidity. | Bord Gais |
| | | Viridian states that a Mi-Merit 2 product should be developed to reduce concerns over the DC contracts and the formulation of both their price and quantity. | Viridian |
| | | Airtricity note that liquidity is very poor. Available contracts are limited and most have very long delivery periods. No options for true hedges exist as there are no sell-markets, only buy-markets. The high floor prices do not encourage competition and do not reflect true residual values for electricity. Possible solutions could be sought by examining the case in UK and Europe where electricity can be bought physical forward and by replacing floored auctions with a bids-and-offers mechanism. | Airtricity |
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| **4** | How do you foresee the contracts market developing in the SEM, over the medium and long-term? | Depends on how the regulators regulate incumbent generation and supply companies. The regulators will need to consider and consult on the appropriate degree of regulation of incumbents to ensure that a competitive market develops. Measures beyond non-discrimination clauses and EPO requirements in licences may be required. In addition the move to an all-island retail market would improve contract liquidity – they would support progress on this issue.<br><br>The move to a regional market will improve contract liquidity. Support the development of a framework for regional integration. | Endesa Ireland |
| | | States that the vertical integration of ESB would reverse the progress made in developing liquidity into the SEM. Unqualified re-integration would effectively restate a bi-lateral market on the market. There would also be no incentive for ESB to offer CfDs externally.<br><br>BG suggests that the future termination of GUAs will aid liquidity in the market and offer more options to both generators and suppliers in sourcing hedge counterparties.<br><br>In addition the development of day-ahead market coupling with the GB market might improve liquidity and the choices and prices available to participants in hedging their portfolios. | Bord Gais |
| | | The future development of the SEM markets is largely dependent on future changes to rules and policy.<br><br>In the absence of regulatory requirements on ESB PG to sell power through regulated platforms the contracts market in the SEM would collapse.<br><br>There is potential for more liquidity in the market following the introduction of the new interconnector but this will be dependent on the market rules governing its use. | Viridian |
| | | Airtricity do not see much prospect for the development of vibrant contracts markets when the only sizable generators continue to offer CFD products priced well in excess of fair value. In the absence of physically delivered contracts markets, the only way we can see of addressing this will be to comprehensively address commercial cross-border trading across the interconnectors, enabling market participants to effectively seek contracting parties outside the SEM. | Airtricity |
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| **5** | What are the costs and benefits of Directed Contracts (DC) as currently configured? How well does the current price setting mechanism of the DCs work in practice? Should alternative price setting mechanisms be considered and what would be the costs and benefits? | Are of the view that the implicit sunset provisions of DCs make them an appropriate tool for mitigating market power. As the market share of incumbents fall, the regulators role in determining wholesale prices will fall.<br><br>DCs also ensure that contracts are made available to the market with an independent price-setting mechanism. For DCs to continue to be effective it is important that the price-setting mechanism continues to be unbiased and independent. | Endesa Ireland |
| | | The prices for DC auctions are typically not published until after the NDC auctions have taken place. The general market trend has been for NDC prices to be higher than DC prices due to the associated reserve prices of the NDC auctions. BG energy suggests that DC prices are used to set the reserve prices for the NDC auctions. This would be a more transparent mechanism than currently used to set NDC reserve prices. | Bord Gais |
| | | The regulators should improve the transparency of price setting for the DCs. This is particularly important if DC contracts are used as a benchmark for the market – typically DCs have been priced below NDC contracts, the reasons for this should be considered in the review.<br><br>The biggest benefit of the DC arrangements is that it mitigates the exercise of market power by ESB PG by mandating them to sell power. | Viridian |
| | | Airtricity states that directed contracts only offer volume hedges. With the likely deregulation of the retail market where these will no longer be used to set tariffs, there will be limited hedging benefits from them. A physical market is more likely to provide improved liquidity and transparency, but then such a market does not align with the SEM principles and design. | Airtricity |
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| **6** | Should the PSO-related contracts continue, taking account of the interests of the end customer? | Are of the view that the Capacity and Differences Agreement (CADA) could be described as a 'PSO-related CfD', while they note that it was not explicitly referred to by the regulator, they state that:<br>• The CADA was entered into following a competition and is now enforced by a legally binding contract;<br>• Tynagh are unsure why the regulator is asking whether it *'should continue'*, given that a binding contract is in place it 'will continue' in their view.<br>• Tynagh state that the interests of the consumer should have been taken into account at the time of designing and running the 2003 Capacity Competition.<br>• The CADA is an agreement critical to the continuation of Tynagh's business model.<br><br>Tyangh seek clarification as to whether the regulators intend to consider the CADA as a 'PSO related CfD'. | Tynagh Energy Limited |
| | | States that auctions for PSO-backed contracts are necessary to foster competition in wholesale and retail markets. Of the view that the ESB should hedge fuel-related PSO costs to eliminate exposure to fuel price volatility. | Endesa Ireland |
| | | PSO contracts have provided a level of flexibility in the type of hedge contracts offered to the market.<br><br>Note that the question is likely to be related to the Department of Communication, Energy and Natural Resources' impending review of the PSO and its inclusion of peat plant. If following the review PSO contracts are no longer made available to the market, regulators will need to look at alternative ways to replace mid-merit and peaking hedge contracts. | Bord Gais |
| | | PSO contracts should be maintained from a wholesale market perspective to the extent that they contribute to liquidity of the contract market. | Viridian |
| | | Airtricity is not aware of any real benefits accruing to end customers from the PSO-related contracts. It does have concerns however about the potential to introduce additional costs over and above what already exists in the support schemes the PSO funds. | Airtricity |
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| **7** | In terms of liquidity and competition, what are the likely impacts on the SEM of the next interconnector and Ireland-UK market coupling? | Believes that it would have a positive impact on contract liquidity and competition – the extent of benefit depending on capacity access arrangements and the success of regulators in developing rules to allow for efficient cross-border trading.<br><br>The barriers to entry identified in the regulators consultation paper on regional integration will need to be addressed prior to the commissioning of the East-West Interconnector. | Endesa Ireland |
| | | Believes that it would increase liquidity and competition in the market, although the impact will be limited by physical, transfer limits, differences in market arrangements between BETTA and the SEM and the extent of price differences between BETTA and the SEM.<br><br>They understand that further interconnection is required to achieve full market coupling, which will give time to consider how the different market rules can be combined.<br><br>The overall outcome could be increased liquidity, significant scheduling and dispatch questions to address and the longer-term likelihood that the benefits of interconnection will only allow the potential liquidity to be realised once SEM and BETTA are more closely aligned. | Synergen |
| | | The developments will augment the level of competition in the wholesale market – though this will depend on how the arrangements are implemented.<br><br>As a centrally dispatched market BG energy would suggest that this is limited to the bi-lateral BETTA market.<br><br>BG cautions against actions that lead to the SEM developing in a way that aligns it more closely with BETTA, as BETTA is currently being reviewed. The relevant authorities need to coordination future actions. | Bord Gais |
| | | The full potential benefits of the next interconnector will only be realised if the correct market rules and rules for the sale of capacity on the interconnectors are put in place. | Viridian |

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|---|---|---|---|
| | | Airtricity notes that the coming on-stream of the East West Interconnector and the coupling of Ireland and Great Britain will most likely bring some improvements to liquidity and competition. However it notes that these are likely to be marginal given the dominance of the incumbents on the local system and that the design of SEM precludes a physical market and so implies that trading opportunities are constrained and can in no way respond to real time events. If a physical market as in most of Europe were introduced into SEM, this could open out much more competition and liquidity, improving the utility of the interconnectors. In addition if forward physical trading took place participants could trade out additional products such as spark spreads. | Airtricity |
| | | | |
| **8** | Are there locational constraints that could give rise to the potential to exercise market power? How is market entry best promoted where there is congestion? | Agree with statement in consultation paper that all market participants have the potential to exercise market power behind an export constraint. The Grid25 program will be important to remove transmission constraints – they believe that greater transparency is required around the program and that the development of a steering committee could help to ensure timely delivery.<br><br>They do not believe that new entry should be promoted where there is congestion – current market rules provide sufficient incentives for new entry to invest in unconstrained areas. The regulators proposals to ignore firm access rights in constrained areas will eliminate investment signals for TSOs and will cause significant uncertainty for generators.<br><br>Believes that the TSOs should be incentivised to minimize congestion. Where locational constraints are uneconomic to eliminate, regulators should explore the possibility of offering Reliability Must Run contracts for units behind the constraints – as introduced in SEM – 114 – 06. | Endesa Ireland |
| | | The best approach to promoting market entry is to provide strong incentives for network operators to deliver a quick and efficient network roll-out in the future. | Bord Gais |
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| **9** | Is there a case to allow vertical or horizontal integration/re-integration of ESB? What would be the costs and benefits? What changes to market rules (especially market power mitigation measures), if any, should accompany further integration? These changes might either involve the relaxation of rules or addition to the rules. What other remedies should be considered? | Does not consider that vertical or horizontal reintegration of ESBs should be permitted until it is determined that all sectors of the retail market are deemed fully competitive.<br><br>State that if the regulators are to allow further integration, appropriate regulatory measures would be necessary to maintain some liquidity in the contracts market – the regulators should note the problems encountered in the UK on this issue. | Endesa Ireland |
| | | Any decision on re-integration would need to take place following an extensive analysis of the potential impact on the market.<br><br>BG does not support the suggested vertical re-integration of ESB's generation and supply businesses, as it would erode wholesale liquidity weakening competition in both wholesale and retail markets.<br><br>In particular they cite ESBs significant market power due to its position as the largest provider of hedge contracts in the market.<br><br>BG does not necessarily object to horizontal re-integration for operational purposes – though this is premised on the basis that there is a clear demarcation and separation between the generation and supply business. | Bord Gais |
| **9** | | Viridian believe that it would only have a negative effect and should not be permitted. | Viridian |

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|---|---|---|---|
| | | The Consultation paper should consider the potential impact on customer welfare that may arise following the removal of business separation obligations on ESB.<br><br>In the view of ESB the removal of business separation would facilitate more effective market risk management by ESB in-line with standard industry practice. It would also provide ESB with more scope to innovate for the benefit of the customer. | ESB |
| | | | |
| **10** | How would increased ESB integration impact the contracts market? If adverse impacts are anticipated, how would they be best mitigated? | It would significantly diminish liquidity in the market, though this could be mitigated by not allowing re-integration or by requiring a percentage of ESB PG and ESB CS contracts to be sold to / purchased from independents. | Endesa Ireland |
| | | Viridian believe that it would only have a negative effect and should not be permitted. | Viridian |
| | | | |
| **11** | Are the current ring-fencing arrangements for ESB and Viridian adequate? | In their view the current arrangements are adequate, but they have concerns that with the move to deregulation and potential for full reintegration, they have concerns of the potential impact on the market.<br><br>They note that these companies have an unfair advantage, particularly access to historic data for the large majority of electricity customers, which gives them an advantage in developing offers to attract or maintain these customers. | Endesa Ireland |
| | | They comment only on their own ring-fencing arrangements.<br><br>They note that the regulators calculation of market concentration includes Synergen within the ESBI grouping despite them being ring-fenced from ESBI and the ESB regulated business.<br><br>They regard existing ring-fencing arrangements as excessive and not required in today's all-island market. | Synergen |

| | | | |
|---|---|---|---|
| | | BG would support horizontal reintegration of ESBs supply and generation businesses, while keeping the current ring-fencing mechanisms in place between the separate businesses. | Bord Gais |
| | | The current ring-fencing arrangements are considered to be both adequate and appropriate, and they would caution against any relaxation or removal of the arrangements.<br><br>Viridian is of the view that the main issue with the ring-fencing agreements is the regulators misuse of them. In particular delays in the implementation of ring-fencing arrangements.<br><br>Viridian call for regulators to adopt a common approach to the use of ring-fencing arrangements. | Viridian |
| | | | |
| **12** | Are there any other ways of addressing market power in the spot and/or contracts markets which you think should be considered? | Regulators should relax and then eventually remove their regulatory tools to mitigate market power as the SEM develops. Relaxing the bidding principles should be examined for independent players in the medium-term and for both independents and incumbents in the longer-term. Strict bidding principles or rules may be stifling innovative bidding strategies which deny end-customers the full benefits of a competitive market. | Endesa Ireland |
| | | Existing provisions for the use of ex-ante regulation – through the market monitoring unit - could be used more effectively by increasing transparency around the units monitoring and sanctioning activities. | Bord Gais |
| | | Future changes to market rules require full transparent consultation and more reasoned decision making.<br><br>They are of the view that spot markets are generally working as intended, but that significant improvements are possible in relation to, but not limited to DCs – in particular relevant to volumes to be sold, products to be made available and the appropriate mechanisms for these sales. | Viridian |
| | | | |
| **13** | Other issues / statements | The lack of a forward curve, brokerage services, exchanges etc. reflect an obvious lack of liquidity that represent a fundamental issue for the SEM going forward. | AES |
| | | IWEA state that the review of market power and liquidity in the SEM should take place within a transparent policy framework given the other ongoing issues under review in the SEM.<br>They also believe that the review should consider the broader investment signals and conditions necessary to encourage efficient investment. | Irish Wind Energy Association |

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|---|---|---|---|
| | | The regulators need to consider a broader range of metrics when seeking to determine the extent of market power in the SEM. In particular they note that as the largest provider of hedge contracts in the market ESB has the potential to considerably diminish liquidity in the wholesale market and consequently in the supply market. | Bord Gais |
| | | Market liquidity in the SEM is currently driven by the regulatory directives placed on incumbents. The recent improvements in liquidity – in terms of number of auctions held and flexibility of contracts offered do not necessarily reflect a robust level of liquidity.<br><br>The price setting mechanism is an important determinant of liquidity. At times the reserve price of some contracts have been set above market prices, which rendered the contracts valueless as a result eroding liquidity. The lack of a facility for re-trading hedge positions between market participants reduces the level of liquidity in the market.<br><br>Meaningful and value-added liquidity is a function of the number, length and flexibility of contract offerings but also transparency in the price setting mechanisms and flexibility in the trading platform. | Bord Gais |
| | | For the BCOP to be a reliable market power mitigation tool, greater strength and transparency is needed in the oversight and capabilities of the market monitoring unit.<br><br>This will become increasingly important as developments in market integration arise. In particular intra-day trading will remove some of the market power mitigation mechanisms in the SEM.<br><br>BG advocates for the development of more transparent and forceful monitoring by the market monitoring unit to instil confidence in the market for all participants. | Bord Gais |
| | | States that the use of the HHI measure to measure market concentration is incorrect for the electricity sector. They advocate for the use of the Residual Supply Index measure. | Viridian |
| | | State that the level of regulatory risk is being increased by the failure of the regulators to adhere to best regulatory practice. | Viridian |

| | | | |
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| | | Viridian view the following pieces of work important for the regulators to carry out:<br>• Analysis of electricity specific market structure measures/metrics – RSI (and/or the binary equivalent, Pivotal Supplier Index (PSI));<br>• Comparison of RSI values with current HHI approach;<br>• Consideration of the implications of adopting an alternative market power metric as a basis for determining DC volumes;<br>• Robust regression testing of DC pricing formulae and pricing analysis that is made available to market participants to enhance confidence in the process given the stated concerns;<br>• Consideration of the proposal to auction mandated DC volumes;<br>• Adherence to best regulatory practice and the RAs' own published guidelines on these matters. | Viridian |
| | | Believe that the regulator needs to make a fundamental decision about its use of regulatory controls in place of allowing the market to determine outcomes. ESB is of the view that greater market dynamics could be introduced by the removal of existing regulatory controls.<br><br>ESB also state that the regulators should provide more information about the context within which the review of market power is taking place. | ESB |
| | | ESB states that the regulators should provide information to stakeholders on the proposed duties and powers of regulatory authorities as part of the Third Package. In particular the potential for an increased role for the Market Monitoring Unit in the emerging regulatory environment. | ESB |
| | | ESB believe that an overview of the structural model of all SEM market participants could further aid stakeholder understanding of the market dynamics. This should include an assessment of the structure of market participants in other markets. | ESB |
| | | The Consultation paper would benefit from an explanation from the regulators on the risks facing participants in the upstream and downstream sectors.<br><br>The Consultation should also assess the probability of the market risks faced by all participants occurring.<br>The risk assessment could be supplemented by an overview of the typical risk management and mitigation techniques available to market participants. | ESB |

## ANNEX 2: SUMMARY OF TERMS OF REFERENCE FOR DAY AHEAD TRADING WORK

**Objectives**
To develop proposals for a means of facilitating trade at the day-ahead stage across the interconnectors between the SEM and GB, having regard to:

- the development of EU Network Codes which will, in all likelihood, mandate the use of implicit auctions at the day ahead stage;
- the ongoing work on intra-day trading across the interconnectors.

**Terms of Reference**

The terms of reference called for economic and technical advice on how best a day-ahead price in a gross mandatory pool such as the SEM could be established, always bearing in mind that the ultimate objective is to use that price to market couple the SEM and GB markets using implicit auctions.
The TOR set out the key issues to be addressed as:

- what is the experience of market coupling in other markets (e.g., the Trilateral Market Coupling area, CWE, Denmark-Germany) and does it have any relevance for the SEM, given the very different market designs in Continental Europe?
- what is the best means of establishing a liquid day-ahead market and a reliable day-ahead price in the SEM, in the light of the potential establishment and recurring costs of establishing a market, the costs of concomitant TSC changes and potential benefits?
- if market coupling is deemed to be best achieved through the auctioning of day ahead CfDs, how can the RAs be sure that liquidity would be sufficient to incentivise participants and traders to use the day-ahead CfD market?
- is the option of mandating that all trades across the ICs take place at the *ex ante* price in the SEM feasible and practicable? What risks would it impose on market participants? How efficient would the market coupling solution be in practice?
- what are the implications of the proposed solutions emerging from the Modifications Committee on intra-day trading for a day-ahead price coupling method for the SEM?
- are there any interactions between a day-ahead price for the purposes of interconnection and market coupling and wider CfD market liquidity issues in the SEM?

Others considerations include:

- Is the presence of a liquid organised market in Ireland a necessary condition for day ahead coupling in the SEM? If so, how can one be established? If one cannot reliably be established, is the existence of an organised market (or markets) in GB sufficient?

- How relevant is the ‘spur’ solution being developed for coupling the GB and Dutch markets across the BritNed interconnector for the SEM? Could it be copied in the SEM? If so how?

- Does the presence of two power exchanges (APX and N2EX) in GB complicate matters for coupling between the SEM and GB?

## ANNEX 3: SCENARIO METRICS

*Table A3.1: 2015: higher level metrics*

| | average margin - total demand (MW) | min margin - total demand (MW) | Net Import/Exports (TWh) | Average SMP price (€/MWh) | Max SMP price (€/MWh) | Min SMP price (€/MWh) |
|---|---|---|---|---|---|---|
| High Coal High GB | 4398 | 1137 | 8.10 | 67 | 483 | 0.001 |
| High Coal Medium GB | 5262 | 2558 | 0.44 | 59 | 582 | 0.002 |
| High Coal Low GB | 6200 | 2909 | -7.65 | 58 | 1000 | 2.906 |
| Low Coal High GB | 4408 | 1014 | 8.11 | 63 | 1000 | 0.001 |
| Low Coal Medium GB | 5163 | 2589 | 1.29 | 56 | 357 | 0.816 |
| Low Coal Low GB | 6176 | 2909 | -7.51 | 56 | 1000 | 2.905 |

| total Consumption (TWh) | Wind output | peak load (MW) |
|---|---|---|
| 39.81 | 11.07 | 7971 |

*Table A3.2: 2020 higher level metrics*

| | average margin - total demand (MW) | min margin - total demand (MW) | Net Import/Exports (TWh) | Average SMP price (€/MWh) | Max SMP price (€/MWh) | Min SMP price (€/MWh) |
|---|---|---|---|---|---|---|
| High Coal High GB | 3995 | 925 | 8.06 | 68 | 1000 | 0.0004 |
| High Coal Medium GB | 4754 | 1946 | 1.35 | 57 | 1000 | 0.0003 |
| High Coal Low GB | 5670 | 2053 | -6.63 | 57 | 1000 | 0.0003 |
| Low Coal High GB | 3995 | 557 | 8.10 | 63 | 1000 | 0.0003 |
| Low Coal Medium GB | 4653 | 1528 | 2.21 | 55 | 381 | 0.0007 |
| Low Coal Low GB | 5636 | 2053 | -6.35 | 53 | 1000 | 0.0005 |

| total Consumption (TWh) | Wind output | peak load (MW) |
|---|---|---|
| 43.82 | 17.06 | 8700 |

| total Consumption (TWh) | Wind output | peak load (MW) |
|---|---|---|
| 44.52 | 17.06 | 8822 |

## ANNEX 4: RSI CURVES

*Chart A4.1 RSI for 2015, high coal, and high GB price*

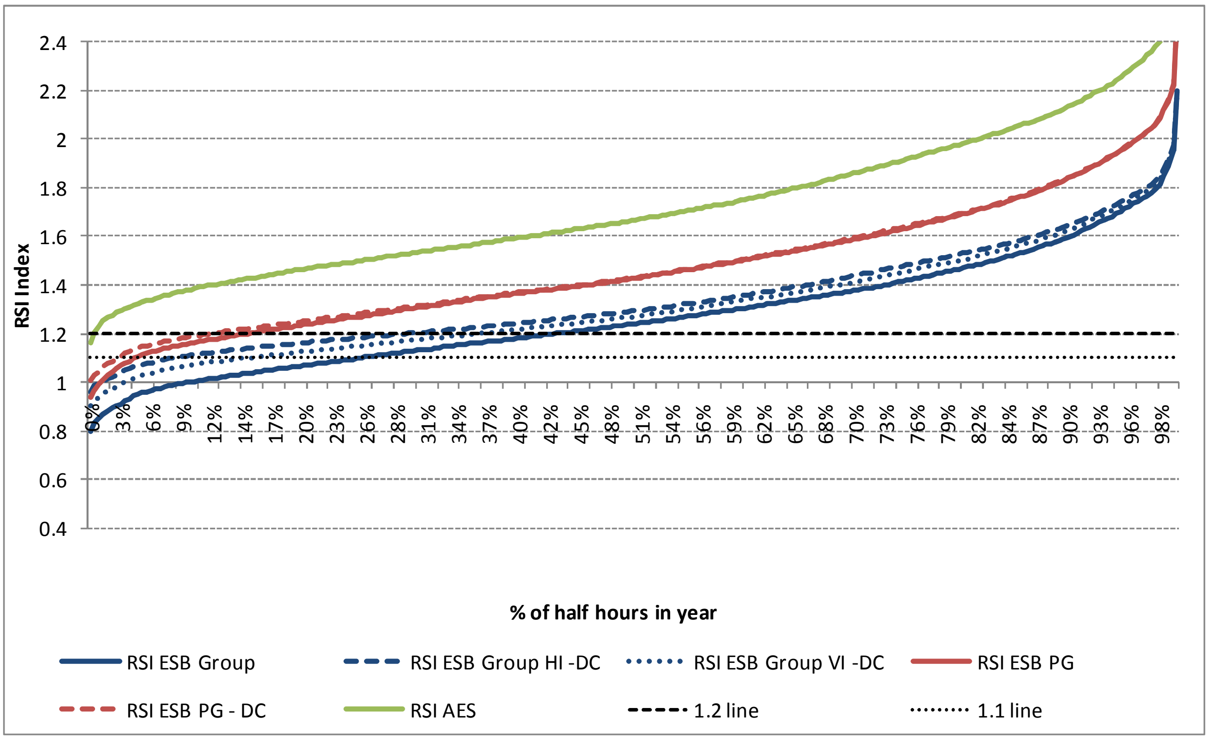



*Chart A4.2 RSI for 2015, high coal, and medium GB price*

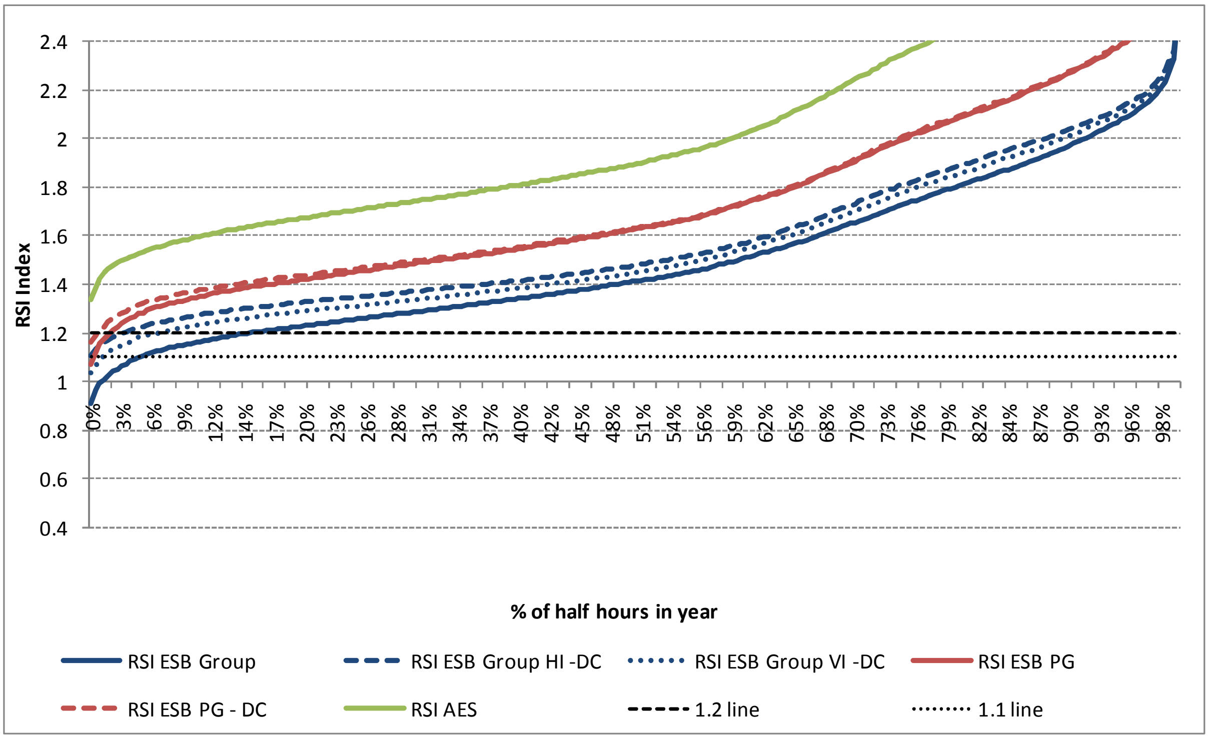


*Chart A4.3 RSI for 2015, high coal, and low GB price*

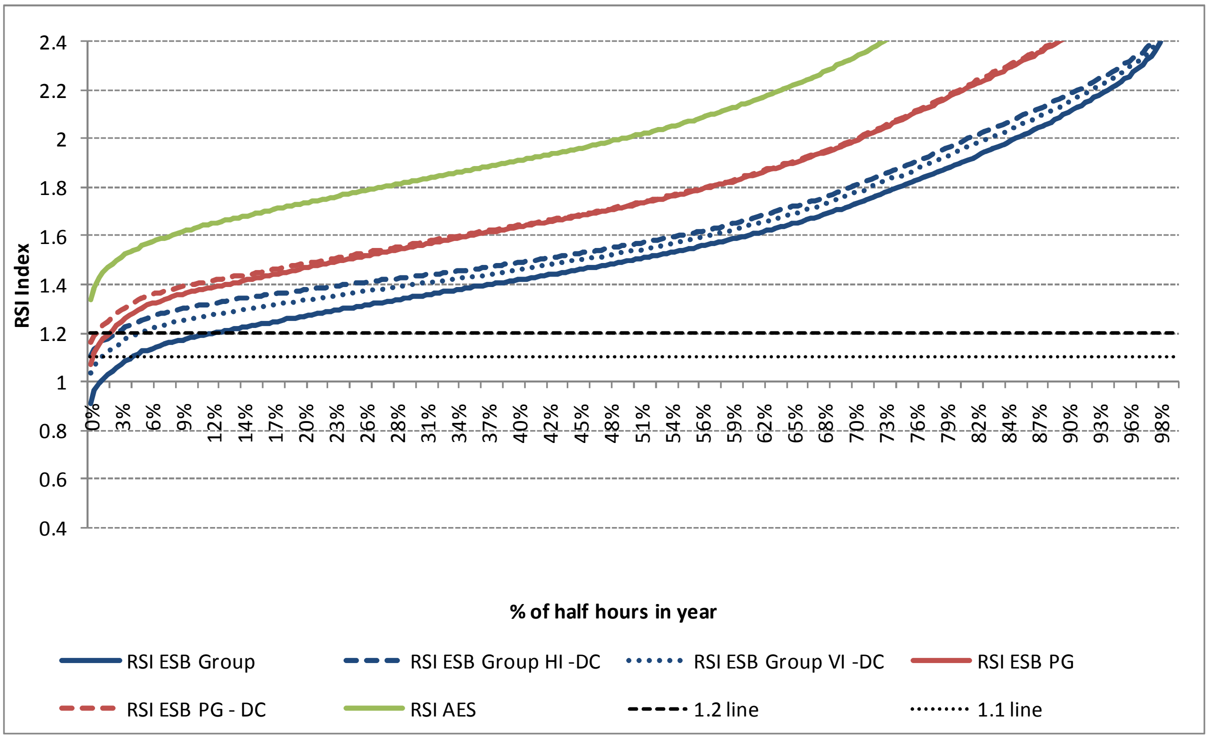



*Chart A4.4 RSI for 2015, low coal, and high GB price*

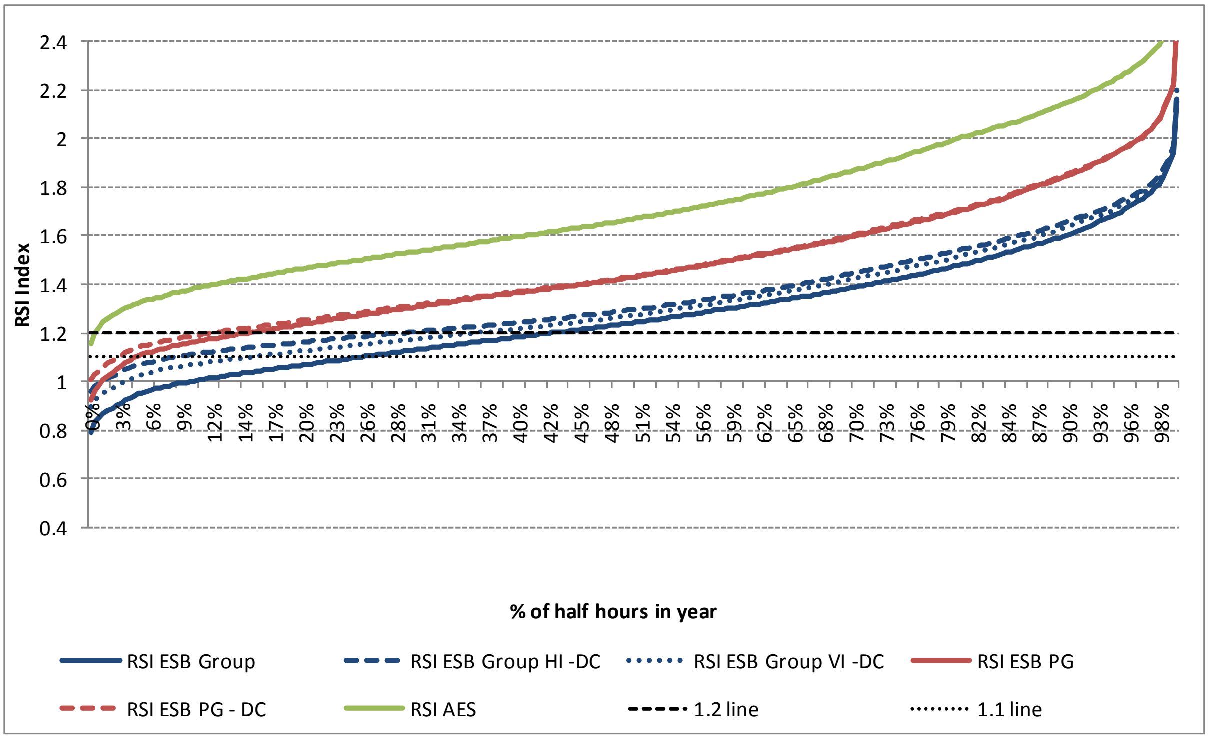


*Chart A4.5 RSI for 2015, low coal, and medium GB price*

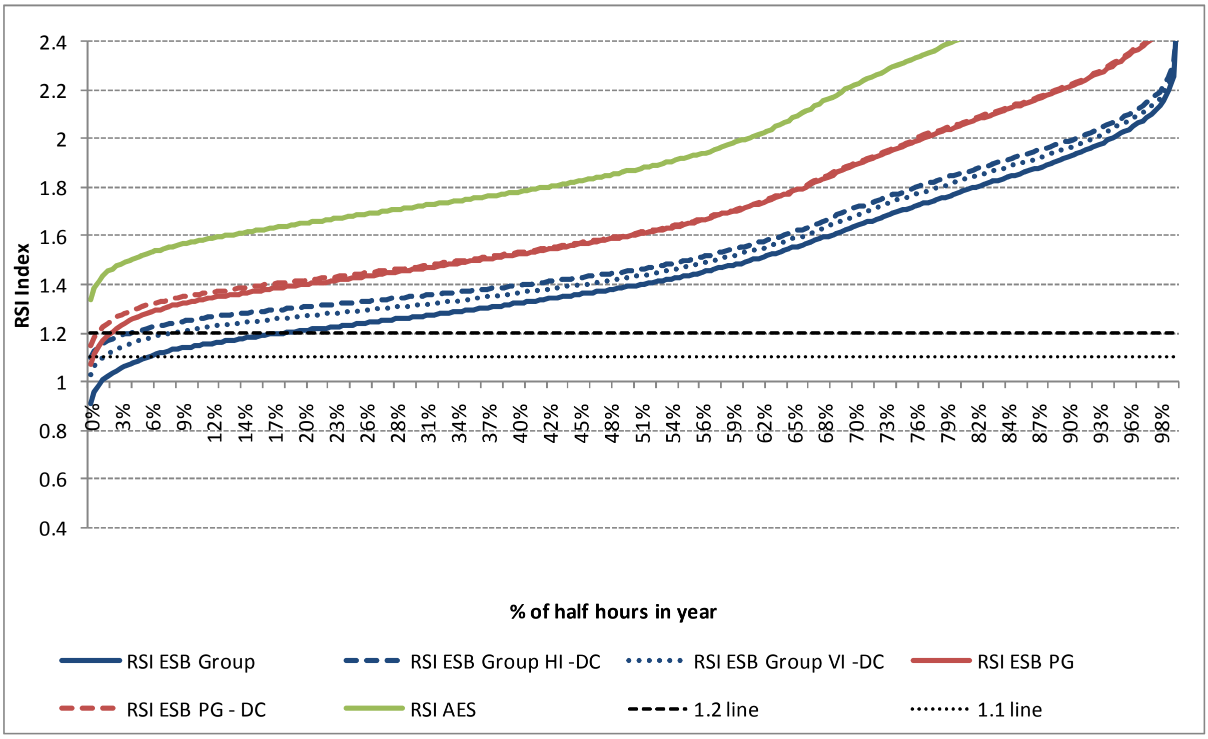



*Chart A4.6 RSI for 2015, low coal, and low GB price*

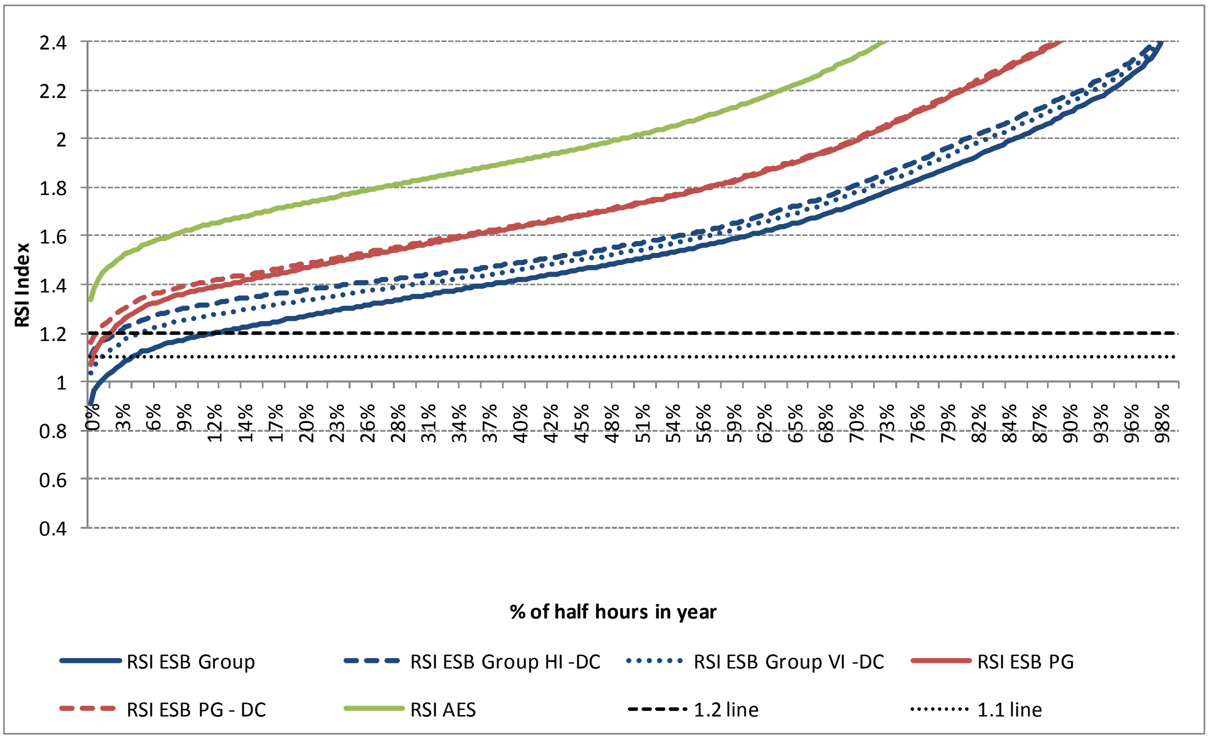


*Chart A4.7 RSI for 2020, high coal, and high GB price*

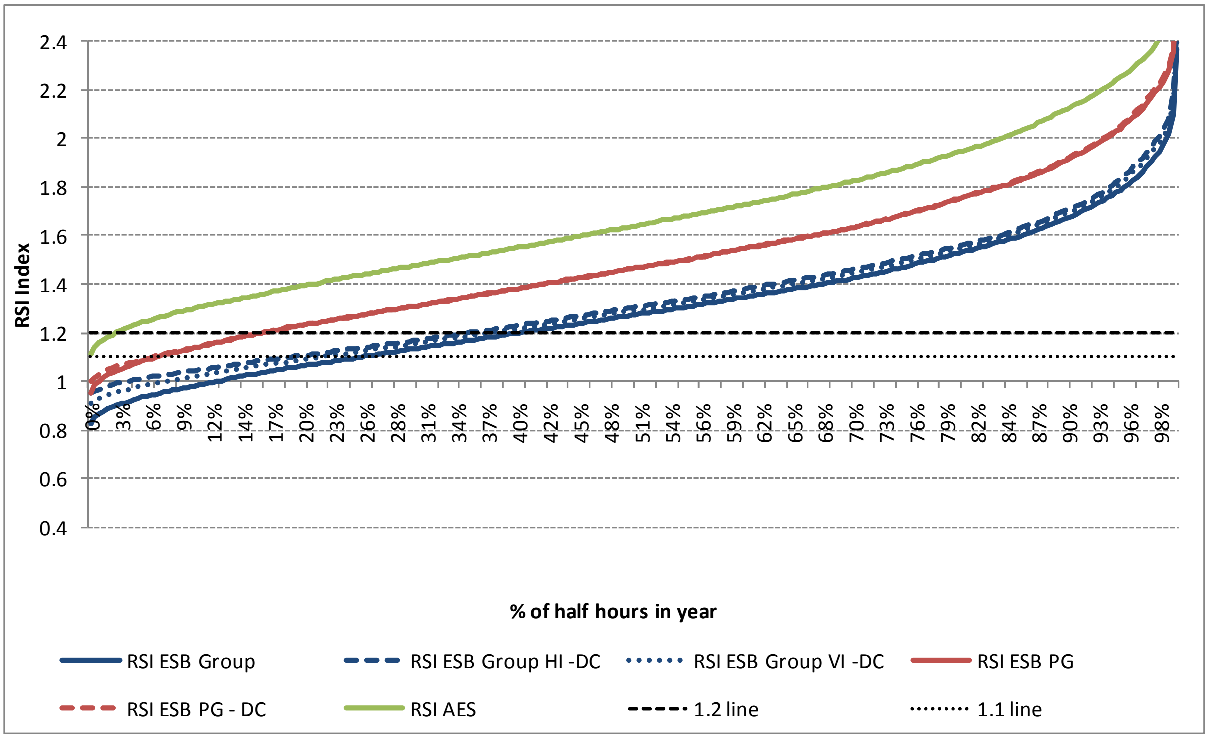



*Chart A4.8 RSI for 2020, high coal, and medium GB price*

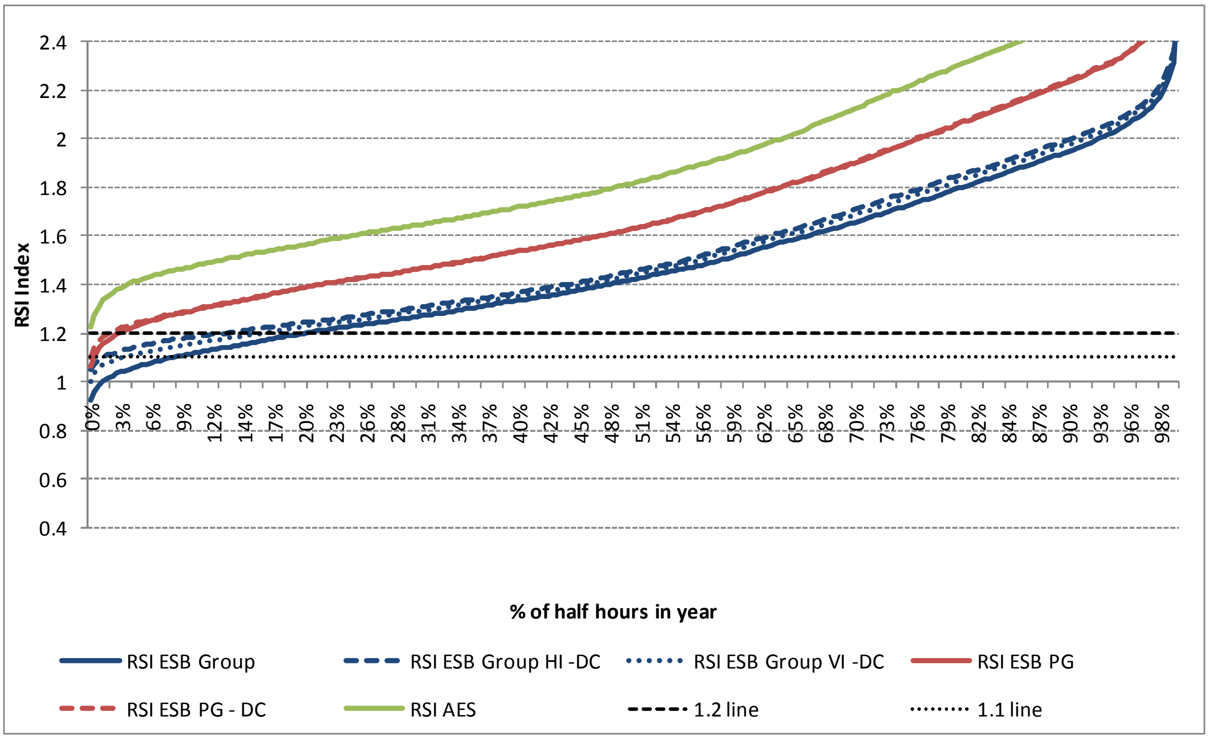


*Chart A4.9 RSI for 2020, high coal, and low GB price*

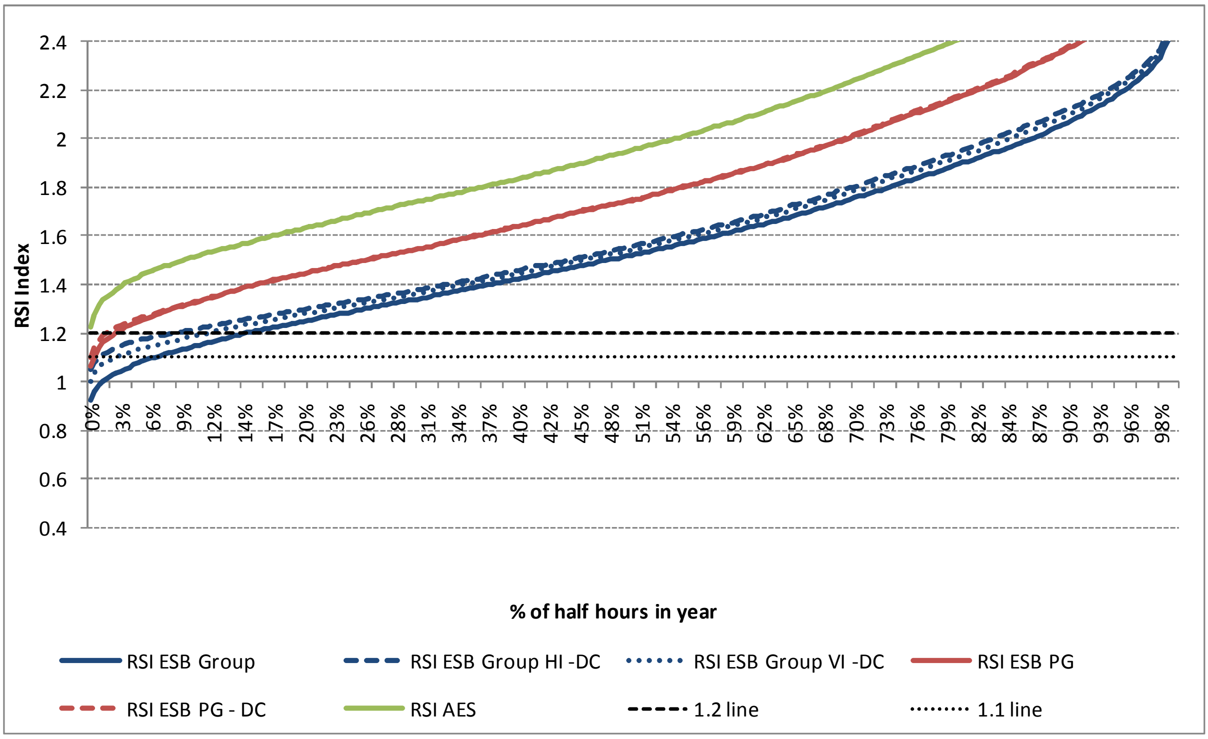



*Chart A4.10 RSI for 2020, low coal, and high GB price*

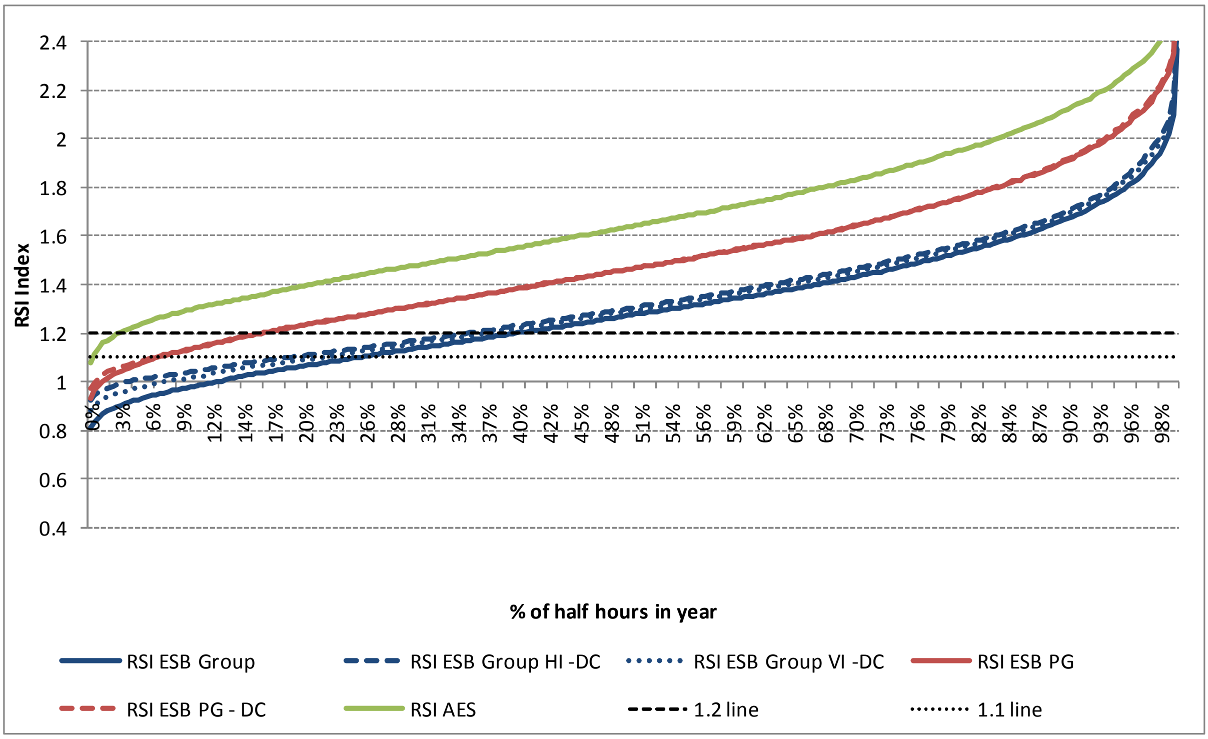


*Chart A4.11 RSI for 2020, low coal, and medium GB price*

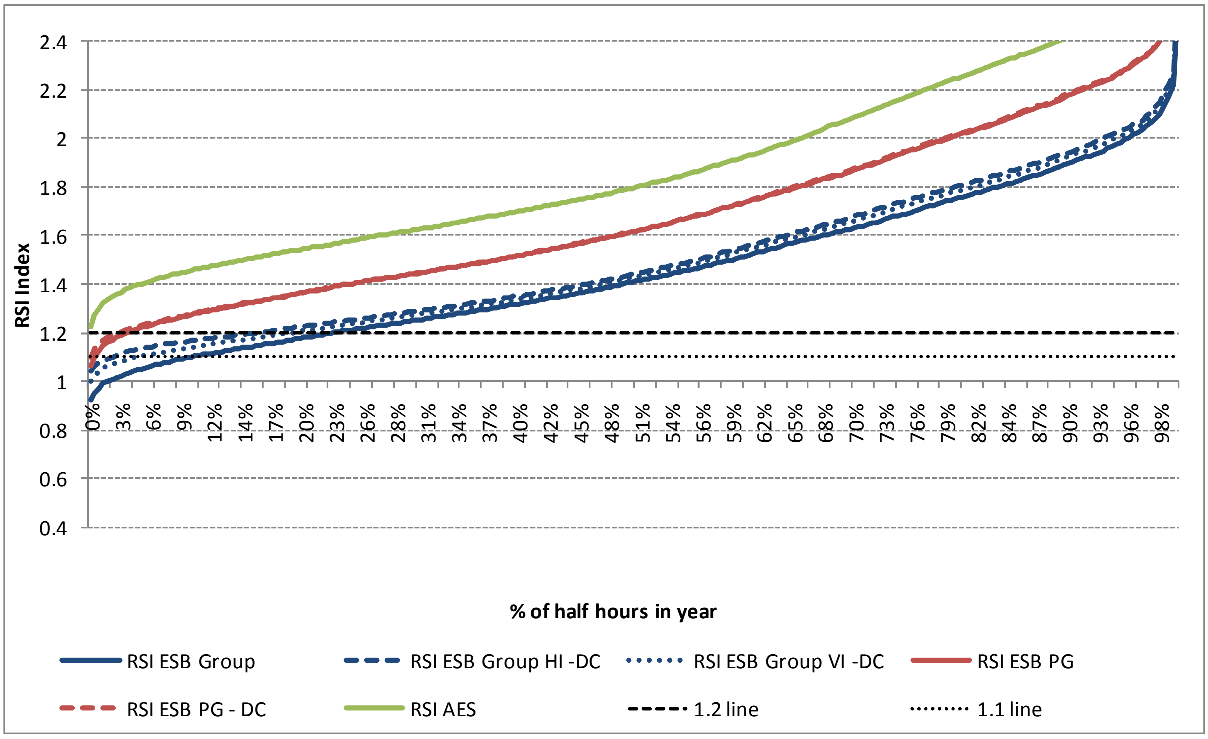
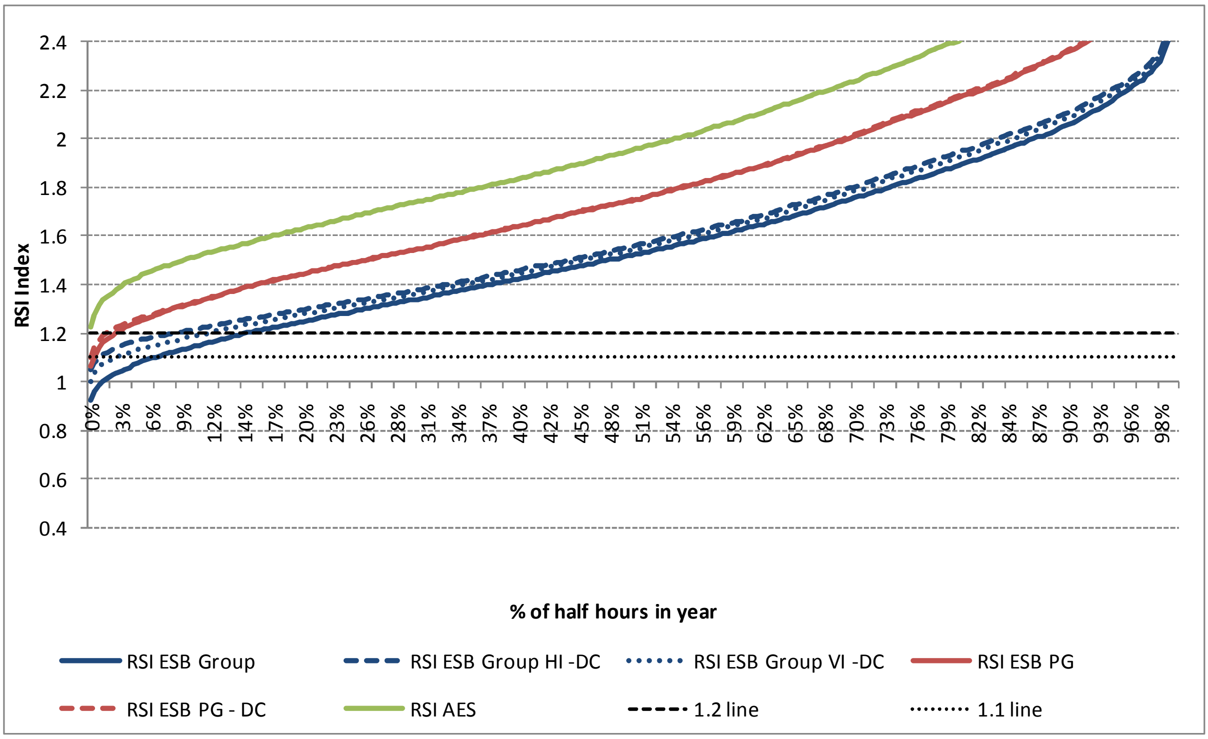



*Chart A4.12 RSI for 2020, low coal, and low GB price*



## ANNEX 5: ESB'S PROPOSALS

This annex contains two proposals provided by ESB. The first is titled 'Industry Change and Progressive ESB De-Regulation' and is a non-confidential summary of a submission to the SEM Committee in February 2010. The second is the 'Proposed Liquidity Undertaking in the context of Progressive ESB De-Regulation' as submitted from ESB to the SEM Committee on 30th July 2010.

INDUSTRY CHANGE AND PROGRESSIVE ESB DE-REGULATION
SUBMISSION FROM ESB TO THE SEM COMMITTEE.
FEBRUARY 25TH 2010

NON CONFIDENTIAL SUMMARY
OCTOBER 20TH 2010

# INTRODUCTION

SUMMARY

BACKGROUND

CASE FOR DEREGULATION

SPECIFIC PROPOSALS

CONSISTENCY WITH REGULATORY OBJECTIVES

CONCLUSIONS

## Industry Change and Progressive ESB De-Regulation

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|---|
| The purpose of this submission is to establish a *prima faciae* case for the SEM Committee to begin the progressive de-regulation of ESB and to request specific regulatory actions. |

**INTRODUCTION**

In this paper ESB presents a case that now is the appropriate time for the progressive de-regulation of ESB and provides a description of the regulatory actions that are sought from the SEM Committee.

Although competition and market positions are radically different from those that existed both at the time when ESB's licences were first introduced and at the time of the design and implementation of the Single Electricity Market, ESB remains subject to the same business separation restrictions.

ESB Customer Supply (CS) has suffered an extreme and ongoing loss of customers at such a rate that, whether or not retail deregulation takes place, its existence as a stand-alone supply business is untenable.

ESB believes that continued instability of CS is likely to damage the retail market, competition and customers.

This paper proposes mechanisms for dealing with these matters by the progressive removal of regulatory restrictions to a schedule linked to time and market events. It also presents evidence that the regulatory actions proposed

- will be of direct and lasting benefit to all customers served by the SEM;
- will further stimulate the development of effective competition; and
- are consistent with sound regulatory principles and with the stated and legislated objectives of the SEM Committee.

**SUMMARY**

While substantial competition has developed in both the wholesale and retail markets of the SEM, ESB currently has imposed upon it a range of regulatory provisions, implemented through specific licence conditions, which materially restrict its ability to do business efficiently and effectively. This set of provisions was introduced at a time when ESB held close to monopoly positions in each potentially relevant market, including the wholesale market and each segment of the retail market and long before the SEM was contemplated. Many of these provisions are no longer necessary as a result of the existence of material competitive pressures, or have been superseded by the development of other effective regulatory instruments. Since SEM go-live, competitive pressures have increased very substantially, in both wholesale and retail markets, changing substantially the backdrop against which the appropriateness of licences should be assessed. The continued existence of these now unnecessary provisions in a number of licences is imposing significant additional costs and risks on ESB, which ultimately impact all customers, and is destabilising ESB's CS business (acting as PES).

In the light of the very significant market developments that have emerged since the introduction of these measures, and based on a well founded presumption that competition will continue to develop rapidly, ESB is requesting progressive removal of these regulatory restrictions to a schedule linked to the timing of key market events. ESB's requests are set out below.

1. Immediately, in order to allow ESB some partial capability to address the untenable risks encountered in respect of CS' exposures as a stand-alone supply business to the end of contracting year 2010/11;

   That the Regulatory Authorities exercise the discretion reserved by Conditions 5.4 and 5.5 and by Condition 6 of each of the PES and PG Licences, to approve in writing arrangements permitting the disclosure of commercially sensitive information between those Licensees and the use within each Licensee of confidential information received from the other, in order to permit PG to hedge on behalf of ESB the risks to which CS is exposed and to permit CS to develop retail products that can be hedged sensibly.

2. Immediately, in order to ensure that licence restrictions are targeted only where needed;

   .Modify the licences granted to ESBIE, Synergen, Coolkeeragh, Wind and the other independent generators within ESB Group as necessary to remove all conditions requiring separation between those businesses;

3. Directly following Retail De-regulation, in order to reduce costs and improve efficiency, thereby bringing benefit to consumers and in order to increase competition in the sub 225MWhpa sector of the market;

   Modify the PES and ESBIE Licences as necessary to remove all conditions requiring separation of those businesses and modify Condition 3B of the ESBIE Licence to remove the restrictions on the Licensee's offering supply to customers not having at least one site whose annual consumption exceeds 225MWhpa.

4. At January 1st 2011, in order to allow ESB to manage the considerable and unacceptable risks associated with a stand-alone Supply Business from the period from October 2011 onwards, to reduce the likelihood of market instability and to protect the interests of consumers, and given that ESB makes a commitment to provide liquidity unless and until an alternative emerges in order to ensure that this removal of separation does not reduce competition in the retail sector;

   Modify the PES and PG Licences as necessary to remove all conditions requiring separation between those businesses.

5. At January 1st 2011, in order that ESB, reasonably in advance of October 2011 may begin to remove duplication of functions within its various generation businesses, reducing cost and risk to the ultimate benefit of consumers;

   Modify the PG Licence and the Licences granted to ESB Group's independent generation businesses as necessary to remove all conditions requiring separation between those businesses.

6. Following the commissioning of the East-West interconnector, in order to ensure that licence restrictions are targeted only where necessary and to ensure no unfair discrimination;

   Review and consult with a view to the gradual phase out the requirement to offer Directed Contracts.

ESB will make a formal request for the licences changes required. It understands that it will then be necessary for the relevant Regulatory Authority to consult on the requested licence changes. In order to ensure a coordinated and consistent approach to renewing licences, ESB suggests that all of these changes are consulted upon through a single process, even though a number of the requested changes will not be put into immediate effect. A single process will help to ensure that the net effect of proposed changes can be understood by potential respondents to the process. The ideal outcome of such a process would be a timetable of agreed licence changes, providing important clarity regarding the evolution of regulatory arrangements over the following two years. Such clarity would allow all market participants to develop robust business plans with a greater degree of certainty, supporting the development of sustainable competition to the ultimate benefit of all customers.

The remainder of this paper provides information in support of ESB's proposals and presents evidence that the actions proposed will be of direct and lasting benefit to all customers served by the SEM and are consistent with the stated and legislated objectives of the SEM Committee.

**BACKGROUND**
The ring fencing provisions within ESB's various licences have been progressively imposed since 1999 at a time when:

- the SEM was not implemented (indeed not even under active consideration);
- there was no interconnection to GB;
- ESB's market share in the relevant (ROI) generation market was close to 100%; and
- customers (even large industrial customers) were unable to choose their retailer.

In advance of progressive market opening and facing a monopoly incumbent, ring fences and business separation were an important element of the regulatory framework established to protect electricity consumers, to encourage ESB's prospective rivals in wholesale and retail markets, and to protect these potential entrants from certain types of conduct which ESB, as the clearly dominant operator, could have chosen to adopt in their absence. In particular, the ring fencing provisions supported two critical licence conditions, namely Economic Purchase Obligation (EPO) and Non-Discrimination Obligation (NDO). These licence conditions provided CER and SEM with a set of regulatory instruments through which it could regulate effectively both CS and PG, in the absence at that time of any prevailing competitive pressure. They also addressed any concerns that ESB might seek to use its dominance in wholesale to benefit its affiliated retail business and vice versa in the light of ESB's dominance in both markets at that time.

Business separation ring fencing, EPO and NDO were essential prerequisites to the development of competition and were key elements of a wider set of regulatory arrangements designed to support market opening and ESB has been fully compliant with all its obligations in this regard. Since those arrangements were introduced, the structure of wholesale and retail markets have changed fundamentally. In the remainder of this section we review how competition has developed in both wholesale and retail markets over the course of the last ten years. Additionally the successful implementation of the SEM (comprised of a set of trading arrangements and a wider set of associated regulatory arrangements) has changed markedly the terms under which power is traded. In the following section we set out the case for progressive de-regulation in the light of these developments, particularly those over the last two to three years.

**Wholesale Generation Market**

Between 2000 and 2010, ESB's wholesale generation market share has declined from over 90% of the ROI market to 45.1%[49] of the SEM. This decline is illustrated in Fig 1, which demonstrates the effectiveness of the regulatory regime in stimulating market entry. There are now six new entrant generators (Viridian, BGE, Tynagh, Bord Na Mona, Endessa and SSE) competing at a wholesale market level, in addition to the ESB businesses and the extant NI generators at Kilroot and Ballylumford currently contracted to PPB. ESB has been supportive of this new entry, providing VIPP products and delivering divestment and closure of generation capacity as per an agreement with CER. ESB Group's market share will fall further in future, in particular following the commissioning of the East-West Interconnector (reported as being on target for completion in 2012), which will also create the realistic prospect of a wider geographic market following coupling with GB. ESB forecasts that its market share (measured by volume) will fall below 40% by 2012, if not 2011. Following market coupling with GB the adoption of a wider geographic market would see ESB's market share fall to around 5%. (ESB's forecast of future generation market share is shown in Appendix 2.)

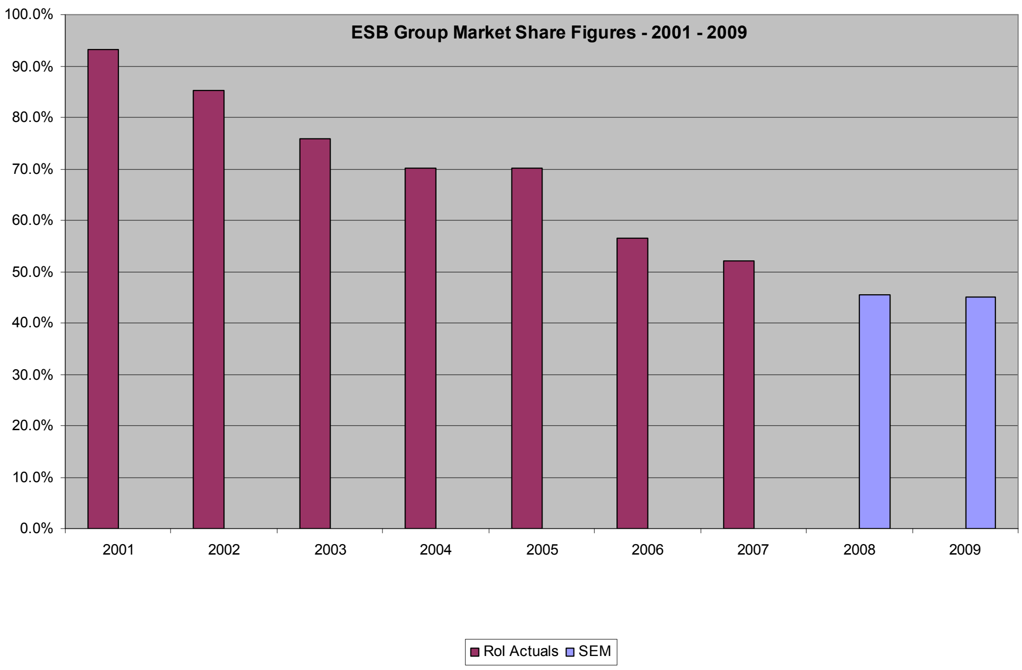



**Figure 1. The Rapid Decline of ESB's Share of the Wholesale Generation Market (ROI to 2007 and SEM in 2008 and 2009)**

49 This includes the output of all of ESB Group's generation, including Synergen, Coolkeeragh, Peat and wind. The equivalent market share of stations owned and operated by ESB PG in 2009 was 26.7%.

The most recent public report of the Market Monitoring Unit (April 2009) concludes that the SEM is functioning as intended, with prices aligning reasonably with those of BETTA. In particular the report regards the correlation between fuel prices and SMP as encouraging evidence of the effectiveness of and compliance with the Bidding Code of Practice.

The Bidding Code of Practice and associated Capacity Payment Arrangements also create an environment in which pricing volatility is reduced, since they mitigate completely the scope for any market participant to exercise market power in the spot market.

As a consequence of these developments, ESB's regulated and unregulated businesses face considerable competition in the wholesale market, the intensity of which has developed considerably since the design phase of the SEM, in the context of a set of market arrangements that prevent the exercise of market power. Competition and market arrangements are now such that if the ring fencing and NDO were removed, the prevailing market structure would ensure that ESB could not exercise market power in the wholesale market or follow profitably the strategies that the original separation provisions and NDO were designed to prevent. Furthermore, the increased level of competition in the wholesale market is now heavily reinforced by a number of existing regulatory provisions focused on conduct in the wholesale market (both spot and contract) such as the requirement for Separate Accounts, the Bidding Code of Practice and the Market Monitoring Unit. The Third Electricity Directive will further enhance the powers of Regulators.

**Retail Market**

The development of market shares in the retail market reveals a similar pattern, as illustrated in Fig 2. Three major supply companies (Energia, BGE and SSE) have entered the market and compete with ESB and ESB's market share[50] has fallen from almost 100% of ROI market in 2000 to 52.5% of the ROI market (and 44% of SEM) as at end 2009. The rate of customer loss has increased markedly since the design phase of the SEM and SEM go live. ESB has supported the development of retail competition, implementing a number of measures agreed with the CER such as VIPP support for new entrant suppliers, the MOIP programme to facilitate switching and the provision of liquidity via the DC/NDC processes.

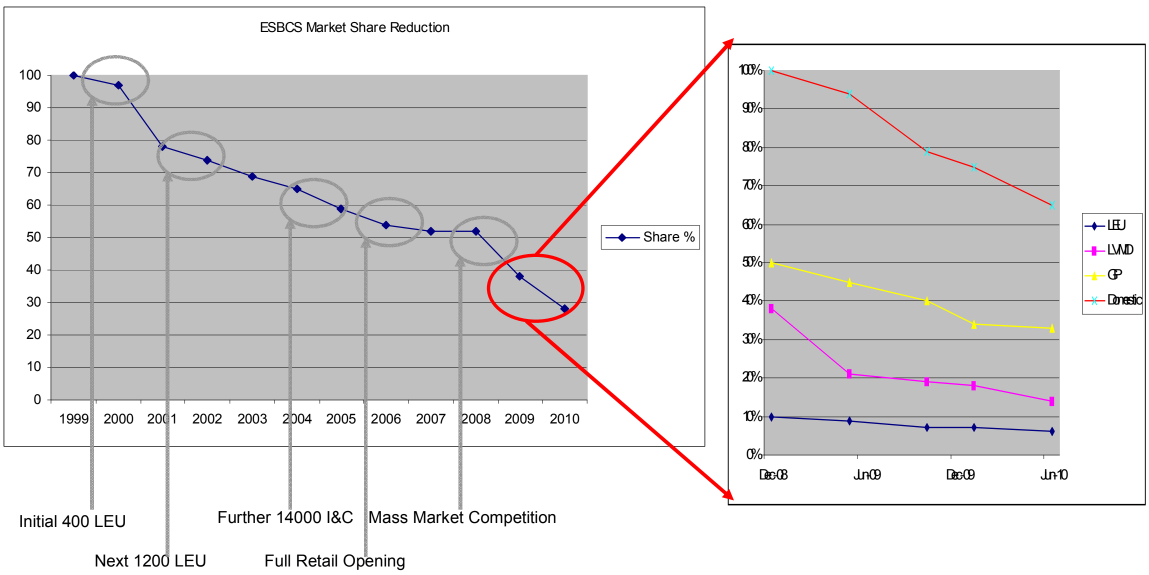



**Figure 2. The Rapid Decline of ESB's Share of the ROI Retail Market.**

Competition for business customers has long been well established and effective. Furthermore, since the advent of SEM ESB has seen two rivals enter and become established in the mass market. In less than one year since the formal launch of BGE's domestic market offering in February 2009, BGE and SSE have in aggregate successfully acquired approximately 480,000 out of ESB's opening 2,000,000 customers, 24% of the mass market (on an RoI only basis). This level of customer loss is unprecedented, greatly exceeding, for example, the rates of incumbent customer share loss observed in GB at any point since those retail markets were liberalised.

Retail competition is likely to become even more effective over the forthcoming one to two year period. Figure 3 shows CS' projected retail shares out to 2011.

[50] For the avoidance of doubt, the market share of ESB CS on an ROI only basis is illustrated

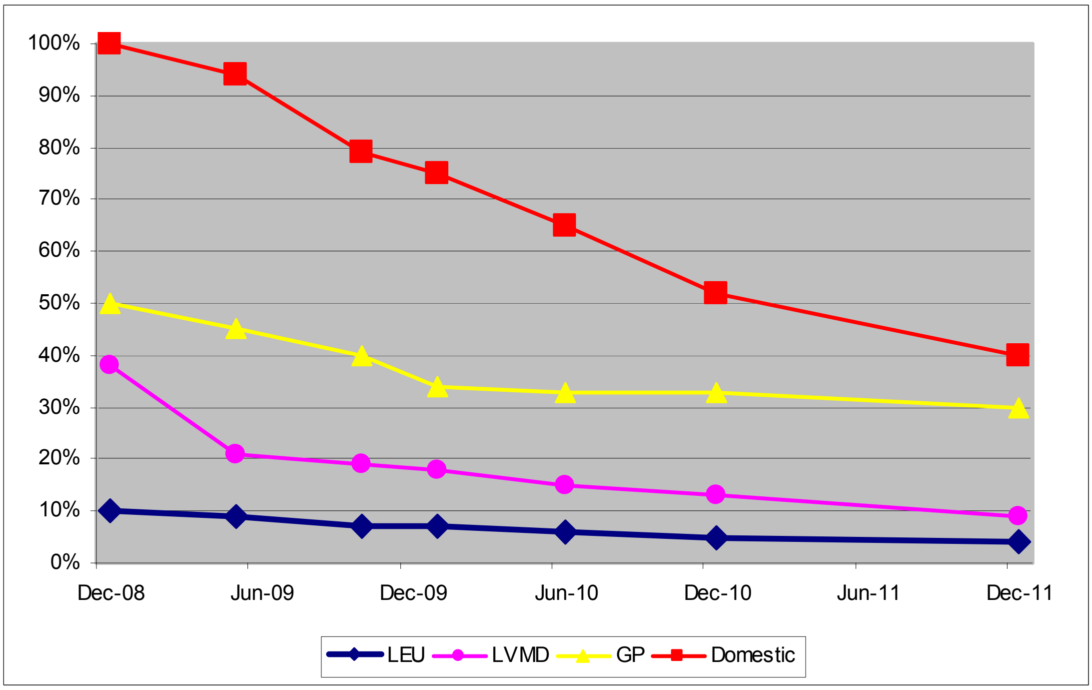



**Figure 3. Actual and Projected CS Shares of the ROI Retail Market**

Given that the wholesale market will be subject to further pro-competitive entry including the commissioning of the first tranche of the East-West Interconnector, creating the prospect of much closer coupling between the SEM and GB. This in turn creates the realistic prospect of retail market entry by existing GB market participants all of whom are vertically integrated. Without change, it is clear that ESB's retail market share will fall as it continues to lose mass market customers. Furthermore, work continues to integrate the retail markets of NI and RoI, over time, widening the relevant geographic market further and reducing ESB's measured market share and power.

**Consequences**

The consequences of these substantial changes in competitive structure are as follows;

In the wholesale market ESB Group's market share has fallen substantially and is expected to fall below 40% by 2012, while ESB PG's market share is already far below this level. More importantly, there is no scope for ESB (or indeed any other market participant) to exercise any residual market power in the wholesale market as a result of the design of the SEM and the close and effective monitoring of the Bidding Code of Practice. ESB's conduct is further moderated through the requirement to offer for sale Directed Contracts. None of these arrangements was in place at the time these business restrictions were introduced, but they clearly create an environment in which ESB's wholesale market conduct is tightly monitored and constrained.

In retail markets any attempt to recover excess costs (of the kind prohibited by EPO) from its domestic customers would result in continued and increased customer loss, as demonstrated by the evident willingness of domestic customers to switch in large numbers to rivals. Similarly, any attempt by ESB to impose excess costs on business customers, through above market purchases of the kind prohibited by EPO, would be likely to result in substantial customer losses. ESB believes that recent market developments (i.e. customer loss) provide ample evidence to support this position. In addition, retail market de-regulation is currently subject to regulatory review, and ex ante tariff regulation will only be removed if the CER is satisfied that any outstanding concerns could be adequately addressed by competitive pressures coupled with the exercise of standard competition law. While ESB believes competition alone is already sufficient to discipline ESB's conduct in retail markets, ESB's proposed timetable for progressive deregulation is consistent with the timing envisaged in the CER's Roadmap consultation.

In the light of these developments and their consequences, it is unambiguously the case that the competition concerns that were in the past addressed through the imposition of business separation restrictions are no longer present. Both the relevant wholesale and retail markets have changed beyond all recognition since a number of regulatory arrangements were put in place Over the course of the last ten years the successful development of competition has created an environment in which it is now appropriate and desirable for certain regulatory controls to be replaced by competition, in accordance with the view espoused by ERGEG. It is against this background that ESB seeks to agree a timetable for the continued, progressive deregulation of its business.

**CASE FOR DE-REGULATION**

The development of competition, coupled with the successful implementation of the SEM has created an environment where further and progressive de-regulation of ESB is now absolutely necessary. There are four primary arguments for this

- To reduce the duplication of unnecessary activities and costs to the benefit of consumers
- To allow ESB to manage the untenable risk associated with a stand-alone supply business
- To avoid potential distortions of the retail market and potential instabilities that are not in the interests of consumers of electricity
- To avoid the likelihood of discriminating unfairly and to avoid regulating in cases where action is obsolete or unnecessary

**SPECIFIC PROPOSALS**

This section sets out ESB's specific proposals with regard to the removal of a range of business restrictions. We highlight six measures and identify the proposed timing of each change, together with the process that might be adopted.

1. Immediately, in order to allow ESB some partial capability to address the untenable risks encountered in respect of CS' exposures as a stand-alone supply business to the end of year 2010/11;

   That the Regulatory Authorities exercise the discretion reserved by Conditions 5.4 and 5.5 and by Condition 6 of each of the PES and PG Licences, to approve in writing arrangements permitting the disclosure of commercially sensitive information between those Licensees and the use within each Licensee of confidential information received from the other, in order to permit PG to hedge on behalf of ESB the risks to which CS is exposed and to permit CS to develop retail products that can be hedged sensibly.

   At present the transfer of information between PG and CS is subject to highly restrictive controls. As a consequence ESB is unable to hedge its position effectively as all relevant information cannot be gathered together and acted upon in a timely manner. Similarly, CS is not provided with the information it would need to understand the consequences of its retail activities on Group risk, nor to allow it to structure and price its retail offerings appropriately.

2. Immediately, in order to ensure that licence restrictions are targeted only where needed;

   .Modify the licences granted to ESBIE, Synergen, Coolkeeragh, Wind and the other independent generators within ESB Group as necessary to remove all conditions requiring separation between those businesses.

   The tight controls on conduct in the wholesale market, as set out in the Bidding Code of Practice and as monitored by the MMU, ensure that no competition concerns can arise in the wholesale market as a result of the removal of these restrictions. The restrictions therefore serve no obvious regulatory purpose, may have no legal basis, while compliance imposes additional costs on ESB.

3. Directly following Retail De-regulation, in order to reduce costs and improve efficiency, thereby bringing benefit to consumers and in order to increase competition in the sub 225MWhpa sector of the market;

   Modify the PES and ESBIE Licences as necessary to remove all conditions requiring separation of those businesses and modify Condition 3B of the ESBIE Licence to remove the restrictions on the Licensee's offering supply to customers not having at least one site whose annual consumption exceeds 225MWh.

   As described above, the removal of this restriction would allow ESB to remove some duplication from its operations, allowing costs to be reduced to the benefit of customers. This proposal would also enhance competition for I&C customers. Given that ESB is seeking the removal of these conditions after Retail De-regulation, presuming the passing of the various market tests, no competition concerns would arise as a consequence.

4. At January 1st 2011, in order to allow ESB to manage the considerable and unacceptable risks associated with a stand-alone Supply Business from the period from October 2011 onwards, to reduce the likelihood of market instability and to protect the interests of consumers, and given that ESB makes a commitment to provide liquidity unless and until an alternative emerges in order to ensure that this removal of separation does not reduce competition in the retail sector;

   Modify the PES and PG Licences as necessary to remove all conditions requiring separation between those businesses.

   As explained above, ESB CS is exposed to considerable market risks that, as a stand-alone retailer, it is unable to manage effectively. Permitting PG and CS to integrate will allow those risks to be managed more effectively, reducing costs for customers and ensuring that retail market competition is not artificially distorted to the detriment of independent retailers.

5. At January 1st 2011, in order that ESB, reasonably in advance of October 2011 may begin to remove duplication of functions within its various generation businesses, reducing cost and risk to the ultimate benefit of consumers;

   Modify the PG Licence and the Licences granted to ESB Group's independent generation businesses as necessary to remove all conditions requiring separation between those businesses.

   The tight controls on conduct in the wholesale market, as set out in the Bidding Code of Practice and as monitored by the MMU, ensure that no competition concerns can arise in the wholesale market.

6. Following the commissioning of the East-West interconnector, in order to ensure that licence restrictions are targeted only where necessary and to ensure no unfair discrimination;

   Review and consult with a view to the gradual phase out the requirement to offer Directed Contracts.

   As described above, the commissioning of the East-West interconnector should ensure that any residual concerns over market in the wholesale market are removed. At this time, the prevailing restrictions will serve little purpose and it is appropriate that their requirement should be reviewed with a view to phasing them out.

ESB will make a formal request for the licences changes required. It understands that it will then be necessary for the relevant Regulatory Authority to consult on the requested licence changes. In order to ensure a coordinated and consistent approach to renewing licences, ESB suggests that all of these changes are consulted upon through a single process, even though a number of the requested changes will not be put into immediate effect. A single process will help to ensure that the net effect of proposed changes can be understood by potential respondents to the process.

The ideal outcome of such a process would be a timetable of agreed licence changes, providing important clarity regarding the evolution of regulatory arrangements over the following two years. Such clarity would allow all market participants to develop robust business plans with a greater degree of certainty, supporting the development of sustainable competition to the ultimate benefit of all customers.

## PROPOSED TRANSITIONS

Along with each of the requested regulatory actions outlined above we have provided a suggested timing. Given the inherent instability of the ESB CS business, and the likelihood of this instability growing in the future, a number of the requested changes are necessary now. Ideally ESB would have desired certain restrictions to have been lifted already. It is already, effectively, too late to make certain changes in sufficient time for them to take hold in advance of the 2010/11 tariff year. However, the changes that are requested immediately will at least allow some improvements in risk management and mitigation to be implemented over the course of the coming year.

In order to prepare with certainty for October 2011, ESB is seeking urgently confirmation of the phased removal of certain licence conditions, although in certain instances the restrictions themselves will persist for some time beyond this agreement. Substantial work will be required to bring about the estimated savings and to create robust, integrated systems. It is anticipated that at least 18 to 24 months will be required to integrate various currently separate businesses so an early determination is critical to ensure that the potential benefits can be captured as early as possible and to prevent a situation where the unprecedented rate of market change, coupled with obsolete separation requirements results in ESB being unfairly discriminated against and finding itself unable to compete.

## CONCLUSIONS

Many of the prevailing business restrictions currently imposed on ESB were introduced at a time when there was almost no competition in either wholesale or retail markets. While there was a clear rationale for their original imposition, there have been major changes in the competitive landscape since those licences were framed and last assessed and, in particular, since the design phase of the SEM and SEM go live. As a result, a number of existing licence conditions are now obsolete (in the sense they address concerns that are no longer reasonable) and are now having unintended consequences and are potentially harming rather than protecting customers and destabilising rather than promoting competition. Further, we are fast approaching the stage where the continued imposition of these restrictions will have the effect of discriminating unfairly against ESB. In the light of this, ESB is formally requesting changes to a number of licences currently held by the ESB group in order to remove a range of unwarranted restrictions on its business.

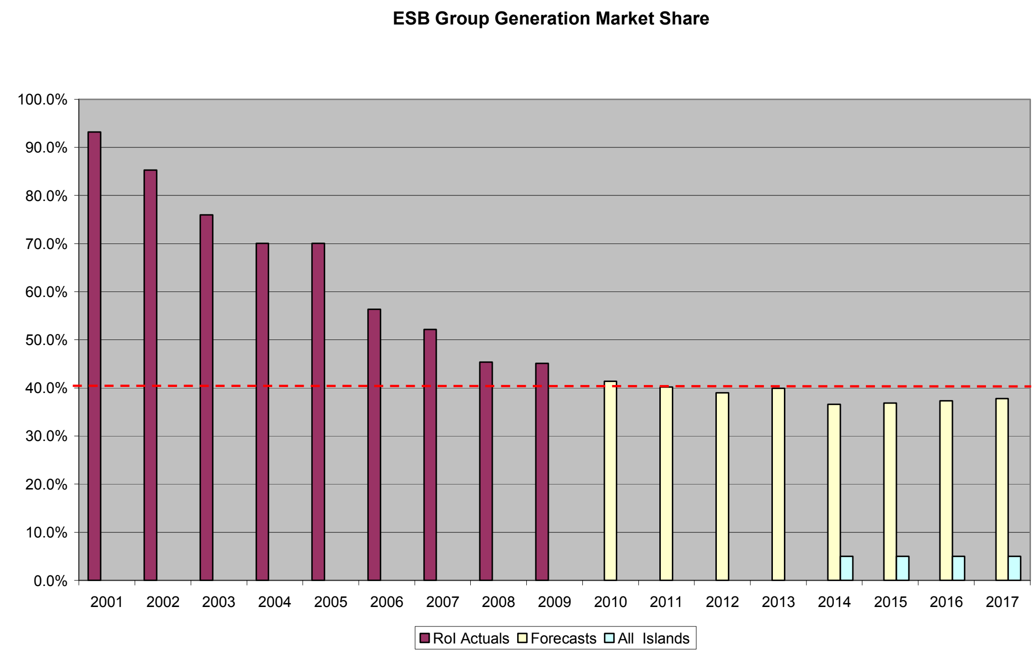
As set out above, the identified business restrictions expose ESB CS to very material market risks, risks that will be inadequately addressed by retail deregulation alone. ESB Customer Supply (CS) has suffered an extreme and ongoing loss of customers at such a rate that, whether or not retail deregulation takes place, its existence as a stand-alone supply business is untenable. Absent the ability to manage those risks across the value chain, there is the scope for significant market distortions to arise to the detriment of all customers and the sustainability of competition.

ESB proposes dealing with these matters by the progressive removal of regulatory restrictions to a schedule linked to time and market events. ESB believes that the actions proposed will be of direct and lasting benefit to all customers served by the SEM, will further stimulate the development of effective competition, and are consistent with sound regulatory principles and with the stated and legislated objectives of the SEM Committee.

ESB requests that the SEM Committee considers these proposals and comes to an early decision in respect of the sequence of proposed actions and licence changes.

## Appendix

## ESB's Forecast of Wholesale Generation Market Share



**Proposed Liquidity Undertaking**

IN THE CONTEXT OF PROGRESSIVE ESB DE-REGULATION
SUBMISSION FROM ESB TO THE SEM COMMITTEE.

30TH JULY 2010

# INTRODUCTION

## INTRODUCTION

ESB, in its submission to the SEM Committee of February 2010 "Industry Change and Progressive ESB De-Regulation", requested modification of the PES and PG Licences as necessary to remove all conditions requiring separation between those businesses "in order to allow ESB to manage the considerable and unacceptable risks associated with a stand-alone Supply Business from the period from October 2011 onwards, to reduce the likelihood of market instability and to protect the interests of consumers, and given that ESB makes a commitment to provide liquidity unless and until an alternative emerges in order to ensure that this removal of separation does not reduce competition in the retail sector".

ESB has discussed such a provision of liquidity with both the Regulatory Authorities (RAs) and with other market participants and has developed a proposal for discussion.

This paper sets out a proposed Liquidity Undertaking for consideration by the SEM Committee in the context of the progressive deregulation of ESB and the removal of separation between ESB's generation and supply businesses.

This submission will not rehearse the many arguments for the progressive deregulation of ESB that have already been presented to the SEM Committee, rather it considers the importance of liquidity in a context which assumes the removal of separation between ESB businesses.

The paper explores those characteristics of the market that have an influence on the need for liquidity, the form of such liquidity and the range of choices that exist for its provision.

The paper goes on to set out a proposal from ESB undertaking to provide a significant level of liquidity in the context of a deregulated business.

**SUMMARY**

The nature of the SEM and the fact that most unregulated Suppliers are integrated with generation means that both the requirement for contracts for difference (CFDs) and the associated risk premiums tend to be low reducing the likelihood of significant levels of trades in CFDs around the SMP.

Any party can trade in CFDs around the SMP and it is not necessary to have an underlying physical position. In addition, because of the possibilities of substitution, the trade in CFDs does not constitute a separate and distinct market and ESB cannot exercise market power in this regard.

ESB understands the challenge facing the market to be one of ensuring that Suppliers and Generators and potential new entrants can generally get access to CFD products which allow them to trade away the risk of their exposure to the SMP. This is a challenge for the market as a whole and the solution should not be provided by just one or two market participants.

There is concern that the removal of separation between Power Generation (PG) and Customer Supply (CS) will collapse liquidity and ESB has committed to ensuring that this will not be the case.

In the context of the removal of separation between its generation and supply businesses, ESB commits to provide products that will allow other market participants to manage their exposure to the risk of SMP movements. This commitment tries to strike a balance between providing a significant level of liquidity support whilst not completely undermining the objectives of the removal of business separation.

ESB commits to the provision to Suppliers of baseload, mid-merit and peak profile products for annual, quarterly and monthly terms, to a volume of 25% of ESB Power Generation's forecast production (depending on market share and certain other constraints).

ESB commits to the provision to Generators of baseload, mid-merit and peak profile products for annual, quarterly and monthly terms, to a volume of 10% of ESB's forecast demand (depending on market share and certain other constraints).

ESB commits to the provision of regular auctions, to reduce the minimum clip size for new entrants down to 0.1MW, ensuring that shape products are available in volumes proportionate to the volume of the overall liquidity undertaking, and to consider offering products based on EFA blocks (such as UK Peak), as an alternative and dependent on market demand.

This is a very significant commitment made in the context of ESB's submission to the SEM Committee of February 2010 "Industry Change and Progressive ESB De-Regulation" and is subject to approval of its request for the removal of the separation between ESB's generation and supply businesses.

**BACKGROUND**

**Liquidity.**

The Single Electricity Market is based around a gross mandatory pool. All Generators must sell all of their output into the pool and all Suppliers must buy out of the pool. As the market clearing mechanism ensures that generation and supply always balance it is clear that, at this level, there is no requirement for liquidity – a Generator in merit will always be able to sell and a Supplier with customers will always be able to buy.

It is also clear that market power can exist in this market and this has already been addressed by the RAs in their design of the market and particularly by the highly regulated nature of the Bidding Code of Practice (BCOP) and by the imposition of Directed Contracts (DCs).

However, in a market where any given Supplier does not always have a perfect generation hedge for their demand and any given Generator does not always have a perfect hedge for their production, market participants are exposed to the risk of movements in the price of power in the gross mandatory pool (the system marginal price or SMP). A party which is long on supply may want to buy a hedge against the risk of the SMP increasing and a party which is long on generation may want to buy a hedge against the risk of the SMP falling. ESB understands from discussions with the RAs that it is liquidity in the purchase and sale of these contracts for difference (CFDs) around the SMP that is the matter at issue. These CFDs are products that allow the purchaser to exchange the risk of exposure to the SMP for a fixed price.

**The Purchase and Sale of CFDs around the SMP.**

The nature of factors surrounding the purchase and sale of CFDs around the SMP is very important.

Firstly, anybody can buy or sell these products. It is not necessary to have an underlying generation or supply position to be a buyer or seller of CFDs around

the SMP. It is not even necessary to be a participant in the SEM to be able to purchase or sell such products. Traders without underlying physical positions buy and sell many equivalent CFDs based around other physical markets, the financial value of such trades often being many multiples of the value of the underlying physical products.

Discussions with the RAs have raised questions such as whether the purchase and sale of CFDs around the SMP constitutes a separate and distinct market in its own right – a contracts market – and, if so whether any participant has or can exercise market power in such a market.

Our analysis is that such a distinct market (comprised solely of CFD contracts around the SMP) cannot be defined. In addition, we consider that, even were such a distinct narrowly defined contracts market to exist, it is not just SEM market participants that can buy or sell CFDs around the SMP and, therefore, no particular participant could or could be considered to have power or to be able to exercise power in such a market.

**Liquidity in the Purchase and Sales of CFDs around the SMP.**

It appears that there are relatively low levels of trade in SMP CFDs. It is worth considering why this might be the case, given that any parties (not just those with physical SEM generation or supply positions) might be interested, as they are for other derivatives, in buying or selling such products.

The regulated nature of the underlying SEM market is significant here. Parties that trade in CFDs around the SMP are essentially buying or selling the risk that the SMP price might rise or fall and, particularly, that it might rise or fall in an unexpected way. Given the regulated nature of bids as a consequence of the Bidding Code of Practice, it is reasonable to argue that SEM prices will be less volatile than prices in other less regulated wholesale electricity spot markets. The Capacity Payment Mechanism has been specifically designed to reduce volatility in the SEM itself (and it appears very successful in achieving this end) whilst the regulated BCOP ensures that the SMP moves very closely with underlying movements in commodities such as NBP gas.

A further aspect of regulation is the fact that benchmark products in the form of DCs are made available at the behest of the RAs and are priced with no risk premium, thereby satisfying demand to a certain extent and undermining prices for CFDs. The process for the sale of PSO CFDs has a similar effect.

These factors when taken together are unlikely to create an environment attractive to those parties that normally trade around volatility, act as creators or providers of risk avoidance products or serve as market-makers.

Furthermore, the fact that the vast majority of the non regulated suppliers in the SEM are vertically integrated to a high degree, also suppresses demand soit is not surprising that there has been no development of an active and extensive trade in CFDs around the SMP.

In conclusion, therefore, it is debatable as to whether a high degree of liquidity in CFD products is required and it certainly appears to be the case that the relative stability and market power mitigation arrangements associated with the SEM together with the vertically integrated nature of the major unregulated Suppliers act to dampen down the development of any potential CFD trade

**So, is there a Problem?**

The consequence of this is that an active or secondary trading in CFDs has not developed and, given the nature of the underlying market, is unlikely to develop in the future. On one level, given the existence of a gross mandatory pool and the relatively low level of SMP volatility, this is unlikely to be a fundamental issue. However, it is unquestionably helpful for market participants in general, for the efficient operation of the market, for customers and, particularly, for potential new entrants. to have access to SMP CFD products in order, from time to time, to be able to transfer their risk to somebody better able to manage it.

So, from discussions with the RAs, ESB understands the challenge facing the market to be one of ensuring that Suppliers and Generators and potential new entrants can generally get access to CFD products which allow them to mitigate the risk of their exposure to the SMP. It is not necessary to have five times or six times the underlying physical position traded. In most cases, parties are likely to be looking for shape to allow them to better match existing supply and generation positions and this should amount to a relatively small volume of their underlying position.

**Whose issue is it?**

The current situation (although it is not possible to be definitive here as CFD trades between counterparties in the SEM do not have to be declared) is that PG provides the great majority of CFDs.

PG provides DCs as mandated by the RAs on a regular basis and, acting as an agent on behalf of the RAs, also auctions PSO products into the market. NIE PPB provides DCs when required, while PG has been voluntarily auctioning an increasing level of NDCs at the encouragement of CER. It appears that there is sufficient volume of CFDs available: had it been otherwise, CFD premiums (over and above reasonable forecasts of future SMP prices) would have risen significantly (and possibly drawing in alternative providers of CFDs).

Many participants in the physical SEM market want to be able to purchase SMP CFDs in order to reduce their own risk and exposure to the SMP but want such risk management products to be provided by somebody else and do not want to pay the premiums associated with buying out risk. In addition, it is apparent that many market participants consider that the provision of risk management products is somebody else's problem and that they need not be part of the solution. Whilst this is normal, it is unreasonable.

The market structure reduces the likelihood of parties external to the physical underlying market being attracted into the provision of CFDs around the SMP. This being the case, it is important that all participants in the physical market participate in the provision of risk management products in proportion to their size, but it is clear that CFD coverage of a relatively low proportion of the underlying physical electricity is all that is necessary.

The current situation in which PG is providing a disproportionate share of CFD products is unreasonable and unsustainable. PG is prepared to be a significant provider of risk management contracts but other parties must also be part of the solution.

**ESB's Contribution to Liquidity**

Since the start of the SEM, PG has offered a considerable volume of its output for sale as CFDs to allow Suppliers to manage their exposure to the risk of SMP movements. During that period, the shape and volume of PG's offerings have been continuously developed to support liquidity in the market.

In the year 2007/08, PG initially offered base-load and mid-merit products in an annual round of NDC auctions. Subsequently, in response to requests from Suppliers, PG offered "mid-merit 2" products and both annual and quarterly products. PG offered similar products in 2009/10.

In 2009/10 at the request of the RAs and in order to facilitate NIE PPB's MiFID compliance requirements, ESB PG adopted the multilateral trading platform provided by Tullet Prebon as the facility for its auctions.

In 2009/10, PG sold 5.8TWh of DCs and NDCs in the annual round of auctions based on a production forecast of 8.3TWh. Further to Supplier requests for increased liquidity, PG sold 0.1TWh of quarterly NDC products in December 2009 and held two auctions for monthly NDC products in Q1 2010, selling a further 0.2TWh.

PG carried out a review of providers of multilateral trading platforms in January 2010. While some parties expressed interest, no new provider has to date entered the SEM so PG continues to auction through Tullet Prebon.

Due to the fall in demand together with moves in coal prices relative to gas prices, PG forecast reduced production in 2010/11. Despite this forecast fall, PG is committed to maintain and increase the volume of CFDs offered for sale for the 2010/11 SEM year.

PG offered 1.4TWh of Directed Contracts in auctions through April and May 2010 and offered a further 3.4TWh of Non-Directed Contracts during June 2010. PG also plans to provide additional short-term liquidity, offering about 1.4TWh during the 2010/11 SEM year.

During this period PG also acted as agent for the RAs auctioning significant volumes of PSO backed CFDs and managing these contracts on their behalf without charging for this service.

Meanwhile, it should be noted that 2010/11 NDC offerings by NIE, the only other provider, currently appear to be substantially less than in previous years. Furthermore, there was no DC obligation for NIE for the 2010/11 tariff year.

In general, ESB has continually developed its liquidity offerings at the behest of the RAs and in response to requests from Suppliers and it will continue to operate in this manner should the separation between PG and CS be removed.

**The Impact of ESB Vertical Integration**

Currently, CS purchases CFDs under the DC allocations, the PSO auctions and various other NDCs from PG and others in order to hedge exposure to the SMP.

Currently, PG is obliged to sell DCs for the purposes of market power mitigation and typically sells a significant quantity of other hedges as part of the NDC process. It should be noted that these sales of NDC products are voluntarily provided by PG at the encouragement of the RAs. The impact of the BCOP is such that, depending on price, the provision of such hedges is not necessarily in the interest of a Generator.

Clearly the removal of ring-fencing between PG and CS will lead to a situation in which, all other things being equal, PG and CS will seek to minimise their combined risk exposure and this is likely to lead to PG and CS trying to balance their positions internally before looking externally and, as a consequence, both selling and buying fewer hedges.

Given the fact that PG is providing the vast majority of the CFDs to allow others to manage SMP risk, this could reduce liquidity in the market.

ESB is conscious of this and will make a commitment to the RAs in relation to the ongoing provision of liquidity in the context of the removal of separation between PG and CS. However, the greater the volume commitment to the provision of external liquidity, the less the value and point of the removal of that separation, the greater the market and counterparty risk ESB would be taking on itself, the higher the cost and price of such liquidity provision.

ESB's share of the SEM market for both supply and generation is in significant decline. If it is important for the market to have CFD liquidity, it is essential that this is provided by a mechanism of which ESB is a part (and a significant part, in keeping with its size) but not a mechanism in which ESB is the sole provider.

So, in making its liquidity commitment, ESB is trying to strike a balance between providing a significant share of the level of liquidity required by the market without completely compromising the point of removing the separation between its CS and PG businesses and without accepting more market risk than would be consistent with sound corporate governance.

## OTHER CONSIDERATIONS AND CAVEATS

### Asymmetry in Buy/Sell Requirements

The exposures of Generators and Suppliers to the risk of SMP movements are generally different.

Currently most Suppliers offer customer tariffs that are fixed for a period of time into the future. Absent tariffs that float as the SMP moves, such Suppliers are clearly exposed to rises in SMP and rationally will seek to hedge the risk of SMP increases.

On the other hand, Generators are required by the BCOP to bid their marginal (floating) avoidable fuel cost into the market. It is rational for a generator, therefore, to keep its fuel floating as, if it is in merit and runs, it will receive that floating fuel price. So, if a Generator enters into a CFD that fixes its income, it thereby increases its risk (as it now becomes exposed to rises in fuel prices).

Therefore, it is expected that there will be a lower demand for products that help Generators to manage their exposure to SMP than there will be for Suppliers.

ESB's Liquidity Undertaking reflects this.

### Trade off between the Frequency of Auctions, the number of Product Types and Depth.

For any given volume of product, there is clearly a trade off between the number of product types (annual baseload, annual peak, quarterly baseload, etc) and the depth of each product that can be made available for sale.

Similarly, for a given volume of product, there is a trade off between the frequency of auctions (month, quarterly etc) and the depth of product that can be made available at each auction.

ESB has considered comments from the RAs and feedback from various existing counterparties in relation to the frequency of auctions. Considering the purpose of the provision of liquidity and given that the majority of customer demand is likely to be priced under annual tariffs, ESB is of the view that the volume of product made available in annual auctions should predominate. ESB is committed to trying to achieve a good balance between product varieties, auction frequency and depth, consistent with risk management requirements, customer tariff structures and the availability and structure of fuel hedges. However, it is considered likely that weekly or daily products would face insufficient demand and would reduce availability of more critical monthly, quarterly and annual products.

ESB also understands that market participants value the certainty of knowing what products and volumes will be auctioned into the future.

**The Shape of Liquidity**

DC and NDC products are currently sold on the basis of baseload, mid-merit and peak profiles.

ESB is happy to continue to sell products on this basis.

However, the increasing use of the Moyle interconnector, the imminent arrival of the E-W interconnector and various market discussions seeking to facilitate increased trade between GB and SEM indicate that it might be sensible at some stage to provide products based on EFA blocks.

ESB is willing, within the scope of the overall Liquidity Undertaking, to consider the development and sale of products profiled on the basis of various EFA block combinations (rather than existing mid-merit and peak definitions) should that be the general requirement of the market.

**ESB's Unregulated Generation and Supply Businesses**

ESB's Liquidity Undertaking is developed in the context of the potential removal of separation between PG and CS and is designed to mitigate concerns about the possible collapse of liquidity consequent on the removal of that separation. For this reason commitments and volumes relating to generation positions refer to PG generation. However, given that the deregulation of CS is an ongoing process, commitments and volumes in the Liquidity Undertaking that refer to supply positions are expressed in relation to the total ESB supply position (i.e. the total of ESBIE and CS).

Within its submission to the SEM Committee of February 2010 "Industry Change and Progressive ESB De-Regulation", ESB requested removal of the separation not only between PG and CS but also between PG and ESB's unregulated generation businesses. Should some or all of this be permitted, ESB will work with the RAs to describe the Liquidity Undertaking in terms of the overall generation position so that the same absolute volume of liquidity is maintained.

Within the liquidity commitment, references to market shares are understood to be ESB's total share of the SEM markets, but excluding generation output sold under PSO.

**New Entrant Considerations**

ESB has tried to consider the possible requirements of potential new entrants and, in particular, the suggestion from within the RAs that while market participants might want to or choose to be vertically integrated, it ought not be a necessary pre-condition of market entry.

ESB considers one of the key requirements of new entrants (whether Generators or Suppliers) is the knowledge that they can be certain of access to a regular, frequent and predictable source of liquidity.

For new entrants with small or developing positions, whether in Supply or Generation, ESB considers that access to sufficiently small lot or clip sizes is of fundamental importance and ESB will cater for this in its Liquidity Undertaking.

**Forecasts**

Because the market changes and dispatch and demand patterns and positions change over time, it is necessary for ESB to base its Liquidity Commitments on its forecast position (forecast generation, forecast demand, forecast market share) from time to time.

ESB intends to carry out these forecasts on a quarterly basis and in a transparent manner and is happy to share outcomes for such forecasts with the RAs, to the extent to which they impact the Liquidity Undertaking in any way.

**Pricing**

ESB will price all products covered within the Liquidity Undertaking (with the exception of the DCs which are priced by the RAs) in accordance with its latest market models and forecasts and taking into account its view of the risks of market movements.

ESB will continue to apply appropriate credit and counterparty terms to products made available under the Liquidity Undertaking.

**Legal Requirements**

ESB is obliged to operate within the terms of the Financial Transactions of Certain Companies and Other Bodies Act, 1992 ("the 1992 Act"), in conjunction with the Specification of the Minister for Finance. This limits ESB in relation to the counterparties with whom it can deal in derivative products such as CFDs and to the nature of such contracts.

While ESB is committed to providing market liquidity, our ability to contract with some market participants (depending on credit ratings or the posting of collateral) may be constrained by the terms of the Specification. Also, by virtue of the terms of the Specification, ESB cannot extend its provision of liquidity to the market to the extent that ESB would be buying or selling CFDs against generation or demand which are not expected to be realised.

**SPECIFC PROPOSALS**

ESB is conscious of the importance the Regulatory Authorities ascribe to the continued provision of liquidity in the form of the availability of products to manage the risk of SMP movements. ESB understands that this is an issue of importance not only for existing market participants but particularly for potential new entrants.

ESB appreciates that, given its size in the generation and supply markets, there is a reasonable expectation that it should play a significant part (whilst not shouldering the whole responsibility) in helping to solve market difficulties with respect to the provision of liquidity.

Given that PG currently provides the lion's share of liquidity (through DCs and voluntary NDCs), ESB understands that there will be concern that liquidity will collapse should the separation between PG and CS be removed. ESB is prepared to commit to making a significant level of liquidity available in the context of the removal of separation between PG and CS.

In the context of the removal of separation between PG and CS, ESB is prepared to commit to making available liquidity as follows;

**The Shape of ESB's Liquidity Undertaking**

Having consulted with the RAs and with various market participants and CFD counterparties, ESB proposes that in relation to liquidity shape it will commit to offer;

Annual products offered quarterly (consistent with fuel hedge availability);
Quarterly products for terms of up to one year ahead and offered monthly; and
Monthly products for terms of up to a quarter ahead, offered monthly.

Annual, quarterly and monthly products will be offered shaped as baseload, mid-merit and peak profiles as is reasonable within the profile of forecast generation. ESB is also prepared to consider offering similar products based on EFA blocks (such as UK Peak), as an alternative and dependent on market demand.

ESB will commit to ensuring the shape products (mid-merit and peak) are made available in volumes generally proportionate with the overall liquidity commitment (so, if the Liquidity Undertaking is for an overall commitment of X% of PG's forecast production, ESB will commit to ensuring that at least X% of PG's forecast peak and mid-merit production is made available as CFDs.)

In order to support smaller new entrants, ESB is prepared to reduce the clip or minimum contract size for new entrants down to 0.1MW.

In consultations with the RAs, the issue of new entrant generators and liquidity from the perspective of the management of their risk has been raised. Although being able to buy products mitigating SMP risk is less important for Generators than for Suppliers, ESB is prepared to make a commitment to provide products in which Generators can swap an exposure to the SMP for a fixed revenue stream. This is a significant new departure for ESB.

In order to improve certainty for market participants, ESB will, on a quarterly basis, provide a programme of the anticipated auction dates, products and expected volumes for the subsequent 12 month period.

**The Volume of ESB's Liquidity Sell Undertaking.**

**Preamble**

For the purpose of this commitment, the term "Liquidity Sell" is used to mean a CFD product that is sold so that a Supplier can manage the price risk of buying power at SMP by effectively paying a fixed price for power. The term "Liquidity Buy" is used to mean a CFD product that is sold so that a Generator can manage the price risk of selling power at SMP by effectively selling power at a fixed price.

ESB has made a commitment to reduce from almost 100% of generation in the ROI market some ten years ago to a 40% market share of the SEM. In this context, ESB will make its commitment based on a 40% share of the generation market, with the level of the commitment rising or falling should ESB's share of the generation market be forecast to be above or below this 40%.. (Note, in this regard, ESB's output determining its share of the SEM generation market does not include output from the Peat plants where the output is sold on behalf of the CER.)

ESB is not in the business of trading CFDs and other financial derivatives for the sake of it and considers it important to reduce to a minimum the extent to which the delivery of any liquidity commitment puts it in a position of trading financial products without an underlying physical position or increasing its market, credit or operational risks to levels that are inconsistent with sound corporate governance and risk management practices. ESB is also bound by the terms of the 1992 Act as outlined above. PG's forecast generation has varied considerably over the past number of years, and even month-to-month,

depending on demand, market entry, interconnection, wind, relative fuel prices and so on. It is appropriate therefore that the Liquidity Undertaking is based on PG's forecast production at any given point in time.

In the absence of information to the contrary, ESB assumes that DCs will continue to be imposed for the purposes of generation market power mitigation. ESB's Liquidity Undertaking, therefore, is stated inclusive of any DCs. It is understood that if the DCs imposed for a given period exceed the stated liquidity commitment for that period, ESB will make the DC volumes available.

It makes sense, if the separation between PG and CS is removed, for ESB to try to reduce risk across the value chain as this will reduce the price to the end consumer. ESB's risk associated with the provision of liquidity will reduce and hence its ability to offer liquidity will increase based on the availability of liquidity from other sources such as other market participants. (ESB will be more relaxed about selling liquidity if it knows its chances of being able to access liquidity elsewhere are high.) It makes sense therefore, that ESB's Liquidity Undertaking must at some level be dependent on the level of ESB's access to alternative hedging products.

ESB is offering a Liquidity Undertaking in the context of the removal of separation between PG and CS, the purpose of which is to allow ESB to better manage its risk and to reduce inefficiencies to the long-term benefit of electricity consumers. This objective cannot be achieved if the liquidity commitment is so large that only a very small proportion of CS sales can be internally hedged by PG. It makes sense, therefore, that the Liquidity Undertaking be to some extent dependent upon the degree to which CS' demand can be internally hedged after discharge of the liquidity commitment.

**Volume of Liquidity Sell Commitment**

ESB will offer a Liquidity Sell Commitment of 25% of PG forecast output based on an ESB 40% generation market share. (Note that in this regard PG forecast production does not include output from the Peat plants.)

ESB will offer a Liquidity Sell Commitment of proportionately more than this to the extent to which ESB's forecast market share of generation is greater than 40%. Equally, ESB's Liquidity Sell Commitment will reduce proportionately as its forecast market share of generation reduces below 40%. (See Appendix 1)

The Liquidity Sell Commitment is inclusive of any DCs imposed for market power mitigation and will be no less than the DC volume imposed.

The Liquidity Sell Commitment reduces to the extent to which it reduces PG's capability to internally hedge at least 30% of ESB forecast demand.

The Liquidity Sell Commitment reduces to the extent to which ESB's access to alternative SEM hedges is reduced.

The Liquidity Sell Commitment ceases in the event of the following;

ESB's share of Generation in the SEM falls below 30%;
The commissioning of an additional interconnector (in addition to the E-W interconnector currently under construction);
The GB and SEM markets become effectively coupled; or
There is a fundamental change of SEM market rules.

**Liquidity Buy Commitment**

**Preamble**

The primary purpose of this Liquidity Buy Commitment (LBC) is understood to be to provide new entrant generators with a mechanism for managing their exposure to SMP. In this regard, ESB is prepared to provide products with baseload, midmerit and peak profiles with annual, quarterly and monthly duration.

ESB's market share of supply has reduced from almost 100% of the ROI market some ten years ago to roughly 37% market share of the SEM. In this context, ESB will make its Liquidity Buy Commitment based on a 40% share of the SEM supply market, with the level of the commitment rising or falling should ESB's share of the supply market be forecast to be above or below this 40%.

ESB is offering a Liquidity Buy Commitment in the context of the removal of separation between PG and CS, the purpose of which is to allow ESB to better manage its risk and to reduce inefficiencies to the long-term benefit of electricity consumers. This objective is undermined if the Liquidity Buy Commitment is so large that it leads to a situation in which ESB's demand is significantly overhedged. It makes sense, therefore, that the Liquidity Buy Commitment be to some extent dependent upon the degree to which ESB's demand is internally hedged after discharge of the Liquidity Sell Commitment.

**Volume of Liquidity Buy Commitment**

ESB will offer a Liquidity Buy Commitment of 10% of ESB's forecast demand based on a 40% SEM supply market share.

ESB will offer a Liquidity Buy Commitment of proportionately more than this to the extent to which ESB's forecast market share of supply is greater than 40%. Equally, ESB's Liquidity Buy Commitment will reduce proportionately as its forecast market share of supply in the SEM reduces below 40%. (See Appendix 1)

The Liquidity Buy Commitment reduces to the extent to which, after the Liquidity Sell Commitment is taken into account, it pushes ESB significantly long on generation.

The Liquidity Buy Commitment ceases in the event of the following;

ESB's share of Supply in the SEM falls below 30%;
The commissioning of an additional interconnector (in addition to the E-W interconnector currently under construction);
The GB and SEM markets become effectively coupled; or
There is a fundamental change of SEM market rules.

**Overall Commitment**

Based on the removal of the present business-separation constraints between PG and CS and finalisation with the RAs of an arrangement in respect of liquidity as outlined above, ESB is prepared, subject to Board approval, to enter into a binding commitment to the effect set out in this paper.

**CONCLUSIONS**

The nature of the SEM and the fact that most unregulated Suppliers are integrated with generation means that both the requirement for contracts for difference (CFDs) and the associated risk premiums tend to be low reducing the likelihood of significant levels of trades in CFDs around the SMP.

Any party can trade in CFDs around the SMP and it is not necessary to have an underlying physical position. In addition, because of the possibilities of substitution, the trade in CFDs does not constitute a separate and distinct market and ESB can not exercise market power in this regard.

ESB understands the challenge facing the market to be one of ensuring that Suppliers and Generators and potential new entrants can generally get access to CFD products which allow them to trade away the risk of their exposure to the SMP. This is a challenge for the market as a whole and the solution cannot be provided by just one or two market participants.

There is concern that the removal of separation between PG and CS will collapse liquidity and ESB has committed to ensuring that this will not be the case.

In the context of the removal of separation between CS and PG, ESB commits to sell and buy products that will allow other market participants to manage their exposure to the risk of SMP movements. This commitment must strike a balance between providing a significant level of liquidity support on the one hand without completely undermining the objectives of the removal of PG - CS separation on the other.

ESB commits to the provision to Suppliers of baseload, mid-merit and peak profile products for annual, quarterly and monthly terms, to a volume of 25% of PG's forecast production (depending on market share and certain other constraints).

ESB commits to the provision to Generators of baseload, mid-merit and peak profile products for annual, quarterly and monthly terms, to a volume of 10% of ESB's forecast demand (depending on market share and certain other constraints).

ESB commits to the provision of regular and dependable auctions, to reduce the minimum clip size for new entrants down to 0.1MW, ensuring that shape products are available in proportion to the overall liquidity commitment, and to consider offering products based on EFA blocks (such as UK Peak), as an alternative and dependent on market demand.

This is a very significant commitment made in the context of ESB's submission to the SEM Committee of February 2010 "Industry Change and Progressive ESB De-Regulation" and is subject to approval of its request for the removal of the separation between PG and CS.

Based on the removal of the present business-separation constraints between PG and CS and finalisation with the RAs of an arrangement in respect of liquidity as outlined above, ESB is prepared, subject to Board approval, to enter into a binding commitment to the effect set out in this paper.

**Appendix 1.**

Liquidity Sell Commitment (LSC)
ESB Market Share of Generation in the SEM (MSoG) (Note, in this regard, ESB's output determining its MSoG does not include output from the Peat plants where the output is sold on behalf of the CER.)
Directed Contract Volume (DCV)
Power Generation Forecast Production (PGprod) (Note that in this regard PGprod does not include output from the Peat plants.)
ESB Forecast Demand (ESBdemand)
Non ESB Hedge Opportunities Volumes (including PSO Volumes) (NHOV)

LSC = 25% x (MSoG/40) x (PGprod)

LSC includes DCV. If DCV ≥ LSC then LSC becomes DCV.

LSC is limited such that (PGprod – LSC) ≥ 30% of ESBdemand

LSC is limited such that NHOV + (PGprod – LSC) ≥ ESBdemand x 50%

Liquidity Buy Commitment (LBC)
ESB Market Share of Supply in the SEM Market (MSoS)

LBC = 10% x (MSoS/40) x ESBdemand

LBC is limited such that LBC <= 50% x ESBdemand – (PGprod – LSC)

**End.**

## ANNEX 6: MODELLING ASSUMPTIONS

The 2010-11 Redpoint Validated Plexos Model was used as the template for this modelling. The following tables include some of the specific assumptions made for the years modelled.

| SEM System Data | Unit | 2015 | 2020 |
|---|---|---|---|
| Embedded Generation | MW | 126.1 | 156.2 |
| WIND | MW | 3,941.0 | 6,069.0 |

| Plexos Unit ID | Station Ownership | Station Fuel | Capacity (MW) | 2015 Available / Retired | 2020 Available / Retired |
|---|---|---|---|---|---|
| AA1 | ESBPG | Hydro | 21 | Available | Available |
| AA2 | ESBPG | Hydro | 22 | Available | Available |
| AA3 | ESBPG | Hydro | 19 | Available | Available |
| AA4 | ESBPG | Hydro | 24 | Available | Available |
| AD1 | ESBPG | Gas | 258 | Available | Retired |
| ADC | ESBPG | Gas | 431.6 | Available | Available |
| AT1 | ESBPG | Gas | 88 | Available | Retired |
| AT2 | ESBPG | Gas | 90 | Available | Retired |
| AT4 | ESBPG | Gas | 90 | Available | Retired |
| B10 | AES | Gas | 101 | Available | Available |
| B31 | AES | Gas | 247 | Available | Available |
| B32 | AES | Gas | 247 | Available | Available |
| BGT1 | AES | Distillate | 58 | Available | Available |
| BGT2 | AES | Distillate | 58 | Available | Available |
| Caulstown GT | Airtricity | Gas | 58 | Available | Available |
| CGT8 | ESBI | Distillate | 58 | Available | Available |
| Contour 1 | Contour Global | Gas | 3 | Available | Available |
| Contour 2 | Contour Global | Gas | 3 | Available | Available |
| Cork PS | Wind Prospect Ireland Ltd | Hydro | 70 | Available | Available |
| CPS CCGT | ESBI | Gas | 425 | Available | Available |
| Cuileen OCGT | Bord Gais | Gas | 98 | Available | Available |
| DB1 | ESBI | Gas | 415 | Available | Available |
| Dublin | Covanta | Waste | 72 | Available | Available |
| ED1 | Bord na Mona | Peat | 117.6 | Available | Available |
| ED3 | Bord na Mona | Distillate | 56 | Available | Available |
| ED5 | Bord na Mona | Distillate | 56 | Available | Available |
| ER1 | ESBPG | Hydro | 10 | Available | Available |
| ER2 | ESBPG | Hydro | 10 | Available | Available |
| ER3 | ESBPG | Hydro | 22.5 | Available | Available |

| | | | | | |
|---|---|---|---|---|---|
| ER4 | ESBPG | Hydro | 22.5 | Available | Available |
| Great Island CCGT | Endesa | Gas | 430 | Available | Available |
| HN2 | Viridian | Gas | 404 | Available | Available |
| HNC | Viridian | Gas | 343 | Available | Available |
| K1 Coal 220 | AES | Coal | 238 | Available | Available |
| K2 Coal 220 | AES | Coal | 238 | Available | Available |
| KGT1 | AES | Distillate | 29 | Available | Available |
| KGT2 | AES | Distillate | 29 | Available | Available |
| KGT3 | AES | Distillate | 41.6 | Available | Available |
| KGT4 | AES | Distillate | 41.6 | Available | Available |
| LE1 | ESBPG | Hydro | 15 | Available | Available |
| LE2 | ESBPG | Hydro | 4 | Available | Available |
| LE3 | ESBPG | Hydro | 8 | Available | Available |
| LI1 | ESBPG | Hydro | 15 | Available | Available |
| LI2 | ESBPG | Hydro | 15 | Available | Available |
| LI4 | ESBPG | Hydro | 4 | Available | Available |
| LI5 | ESBPG | Hydro | 4 | Available | Available |
| LR4 | ESBPG | Peat | 91 | Available | Available |
| Meath | Indaver | Waste | 17 | Available | Available |
| MP1 | ESBPG | Coal | 280 | Available | Available |
| MP2 | ESBPG | Coal | 280 | Available | Available |
| MP3 | ESBPG | Coal | 280 | Available | Available |
| New CCGT 1 | New Entrant 1 | Gas | 440 | Available | Available |
| New CCGT 2 | New Entrant 2 | Gas | 445 | | Available |
| Nore OCGT | Bord Gais | Gas | 98 | Available | Available |
| NW4 | ESBPG | Gas | 163 | Available | Retired |
| NW5 | ESBPG | Gas | 104 | Available | Retired |
| PBC | ESBPG | Gas | 480 | Available | Available |
| RH1 | Endesa | Distillate | 52 | Available | Available |
| RH2 | Endesa | Distillate | 52 | Available | Available |
| SK3 | Aughinish | Gas | 83 | Available | Available |
| SK4 | Aughinish | Gas | 83 | Available | Available |
| Suir OCGT | Bord Gais | Gas | 98 | Available | Available |
| TB4 | Endesa | Oil | 240 | Available | Retired |
| Tarbert OCGT | Endesa | Gas | 285 | | Available |
| TH1 | ESBPG | Hydro | 73 | Available | Available |
| TH2 | ESBPG | Hydro | 73 | Available | Available |
| TH3 | ESBPG | Hydro | 73 | Available | Available |
| TH4 | ESBPG | Hydro | 73 | Available | Available |
| TP1 | Endesa | Distillate | 52 | Available | Available |

| | | | | | |
|---|---|---|---|---|---|
| TP3 | Endesa | Distillate | 52 | Available | Available |
| TY | Tynagh | Gas | 388.5 | Available | Available |
| WG | Bord Gais | Gas | 445 | Available | Available |
| WO4 | ESBPG | Peat | 137 | Available | Available |

## ANNEX 7: CONSULTATION QUESTIONS

The issues/ questions posed by the RAs in their Consultation Paper are repeated below for ease of reference.

1. Do the objectives and criteria for the Market Power Mitigation Strategy remain appropriate today and for the foreseeable future?
2. Will the new interconnector facilitate more competition from Great Britain? If so, what will be the impact on the appropriate market power mitigation strategy?
3. It would be helpful if market participants could explain why they believe demand for hedging products in the SEM exists, and how this demand is not addressed by alternative hedging options, such as through fuel markets.
4. In what way could DCs be reformed in order to promote contract liquidity while also mitigating market power? Do you see merits in replacing the HHI with the RSI in determining DC volumes?
5. Does the recent removal of the EPO condition from ESBCS for business customers and the earlier EPO removal from NIEES for customers with an annual demand above 150 MWhs, together with the removal of ring-fencing between ESBCS and ESBIE, negatively impact on the SEM spot or contract markets? If you consider that it does, are there any replacement conditions required in the SEM and what should they be?
6. Do you consider that the planned forthcoming removal of the EPO for domestic customers in Ireland will have an adverse effect on competition and liquidity in the SEM spot or contracts market? If so, what replacement would you recommend for the SEM? Would the removal of the EPO from NIEES for customers below 150 MWh per annum in NI have a similar impact – and if so, what replacement would you recommend?
7. What if any, implications for competition/ end customer do you see arising from ESB's proposed reintegration:
    a) Horizontally,
    b) Vertically,
    c) Horizontally & Vertically.

    What, if any, new measures would you recommend be put in place for each of the above forms of integration?
8. Would further divestment by ESB encourage deeper competition in the wholesale market?
9. What are the current incentives on generators and suppliers to offer and purchase contracts? Are there any impediments to trading contracts? Do you agree with mandating all generators to offer contracts and/or to become market makers? If not all generators, what criteria would you use for mandating generator to offer contracts or to become a market maker?
10. What product types and in what proportions should a minimum specification market maker offer? What eligibility restrictions should there be to trading with market makers?
11. Do you agree with the CEPA analysis of the ability of structural remedies to address the competition problems presented by the hypothetical structural scenarios outlined in section 6 of the accompanying paper?
12. Will ESB's liquidity proposal be effective in assisting contract liquidity in the market if it is allowed to vertically and horizontally integrate? Will this proposal facilitate competition in the wholesale and retail market? If so, why? If not, why not?

13. Will increased wind penetration affect demand for contracts and the need for market liquidity?

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# MEMO

**TO:** Kevin Hannafin (Viridian)
**DATE:** 2 May 2014
**FROM:** Graham Shuttleworth; George Anstey (NERA)
**SUBJECT:** Reliability Options: Clarification Note

On 5 February 2014, the Regulatory Authorities (RAs) of the all-island electricity market issued a Consultation Paper (the "SEM Consultation") on the future high level design of the Single Electricity Market (SEM).[1] As part of its response, Viridian asked us to prepare a report on the capacity remuneration mechanisms (CRMs) set out in the SEM Consultation.[2]

In the SEM Consultation, the CRMs numbered 5a and 5b concerned centralised and decentralised "Reliability Options". In discussing these options, we commented that "they offered no additional revenue to offset 'missing money'".[3] This memo is intended to clarify that point.

Below, we set out our understanding of the following:

1. The "Missing Money" Problem

2. Institutional Framework of Reliability Options

3. The Auction Process

4. Other Examples of a Reliability Option

Section 5 contains our conclusion.

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[1] **I-SEM – High Level Design** (2014), *Integrated Single Electricity Market (I-SEM) – High Level Design for Ireland and Northern Ireland From 2016*, Consultation Paper, SEM Committee, SEM 14-008, 5 February 2014**.**

[2] Shuttleworth, G., Anstey, G. and Mair, M. (2014), *The Capacity Remuneration Mechanism in the SEM*, Prepared for Viridian, 4 April 2014.

[3] Shuttleworth et al. (2014), section 5.6.1, page 29.

## 1. The "Missing Money" Problem

To start with, we assume that reliability options are intended to help remedy the "missing money" problem – defined as a shortfall in the revenue required to cover the cost of investing in generator capacity. In our report, we say specifically that, "if electricity prices never rise much above the short-run marginal cost of a peaking plant then such plants do not recover their fixed capacity costs (and other plants recover less than their total fixed capacity costs)." [4] The failure to recover these costs will deter efficient investment in generation capacity[5] ("market entry") and encourage inefficient plant closures ("market exit").

Our discussion of reliability options is therefore predicated on the assumption that investors expect future electricity prices to lie below the level needed to remunerate investment in capacity, even if shortages occur. Electricity prices fail to rise due to the explicit caps (or limits) resulting from the Bidding Code of Practice and other SEM market rules, as well as the implicit caps created by the threat of regulatory or political intervention in electricity prices. As a result, investment is below the optimal level.

To make a contribution to security of supply, reliability options would have to overcome this problem by offering investors additional revenue over and above the revenue available from selling electricity in the short-term market and through longer term contracts. Our analysis implies that reliability options – as defined in the SEM Consultation – will not achieve this aim.

Our reading of the SEM Consultation did not indicate that reliability options were intended to deal with any other specific problems in the electricity market. Under specific forms of regulation (set out on page 9), reliability options help to offset retail tariff increases, which may raise the implicit price cap by limiting the regulatory incentive for intervention. However, the SEM Consultation does not discuss the introduction of such regulation. If reliability options are intended to serve some purpose other than raising revenues above market prices, we would welcome clarification of that purpose and a chance to consider it in more detail.

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4 Shuttleworth et al. (2014), section A.2.1, page 35.

5 As in our report, we use the terms "capacity" and "generator capacity" to mean both supply-side provision of capacity and demand-side measures. See Shuttleworth et al. (2014), footnote 2, page i.

## 2. Institutional Framework of Reliability Options

As set out in the SEM Consultation, reliability options represent a kind of Contract For Differences (CFD).

The required quantity of such contracts would be defined centrally (as in any CRM), but procurement of these contracts either would be assigned to one party ("centralised") or allocated among all relevant energy suppliers ("decentralised"). The proposal in the SEM Consultation foresees some kind of auction in the centralised version that sets a single price for these contracts.[6] In the decentralised version, individual buyers would purchase them at different times and at different market prices.

The specifics of capacity market designs vary between jurisdictions. Many designs rely on auctions of contracts for the delivery of capacity several years ahead to allow new generation to bid into the capacity mechanism and prevent volatile capacity prices based on temporary shortages/excesses. The proposed British market design has a lead time between the auction and delivery of four years. In New England, the lead time is three and a half years.[7]

In our report, we described reliability options as a "forward contract for capacity", where the auction would be held in advance of delivery. We noted that the obligation to provide capacity under a reliability option is enforced by a "spot penalty for non-delivery of energy when requested…defined as a 'reference price' of energy, such as the day-ahead price."[8] As we understand it, therefore, the contract would consist (like a CFD) of two separate components:

- The buyer would agree to pay the provider of capacity an amount (PC x Q), i.e. a price per unit of capacity (PC) multiplied by the quantity of capacity (Q(y+4)) offered by the provider for the year (y+4), four years after the auction takes place.[9]
- In return, the provider must provide energy when requested to do so in year (y+4). The owner of capacity will be able to provide energy at its short run marginal cost, but the *opportunity cost* of this energy (which is relevant to all economic decisions) will be the market price of energy (PM) in the year (y+4).

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[6] **I-SEM – High Level Design** (2014), para 10.14.1.

[7] See discussion of British and New England regimes in section 4, below. Capacity contracts of this form pay generators in the year of delivery. The length of elapsed time between the auction and time-period of delivery creates a gap in which generators who have a capacity contract do not receive any payments. At the inception of the New England regime, ISO-NE introduced transitional arrangements for existing and new capacity to bridge this gap. The transitional arrangements were fixed payments of $3-$4/kW month that rose over time running up to the first year of delivery. See LaPlante, D., (2007), *New England's Forward Capacity Market*, Harvard Electricity Policy Group, October 5, 2007, slide 4.

[8] Shuttleworth et al. (2014), section 5.6, page 29.

[9] The year concerned might be more or less than four years after the auction, but the difference is not important for this exposition.

This description of the reliability option, and our comments on it, assume that there is no other method of enforcement, i.e. no obligation to demonstrate available capacity and no penalty for failing to do so. The SEM Consultation does not mention any such enforcement mechanism in sections 10.13-10.15.[10] If in fact reliability options included such an enforcement mechanism, they would be no different in principle from the "capacity auctions" and "capacity obligations" described in sections 10.11 and 10.12 of the SEM Consultation, respectively.

The value of a reliability option, as defined in the SEM Consultation, to the provider can be defined as the difference between the revenue for capacity and the opportunity cost of providing energy to meet the obligation.

[10] Indeed, the SEM Consultation says of option 5a, the "centralised reliability option", "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" (para 10.14.8). We assume that the same is true of option 5b, the "decentralised reliability option".

## Box 1: Flow of Funds with a Reliability Option

Over any period, the net revenue earned by a provider of capacity depends on the summation of flows from various sources over all half-hours, j, in the period. The following equations show how reliability options affect those flows.

First, when the generator is "in-merit", it earns the SEM Market Price ($SMP_j$) for the relevant half hour, i, for all its actual output ($A_j$). The generator is "in-merit" if $SMP_j$ is greater than or equal to its variable cost ($V_j$). Hence, half-hourly revenue for generation ($R1_j$) is defined by the following expression:

$$\text{If } SMP_j \geq V_j, \quad \text{then } R1_j = A_j \text{ x } SMP_j \quad \text{else } R1_j = 0 \tag{1}$$

Second, the reliability option will define a Strike Price ($S_j$). When, in any half-hour, the SEM Market Price rises above the Strike Price, the generator must rebate back to the buyer the difference, $SMP_j – S_j$, for each unit of capacity, $Q_j$, for which it has sold a reliability option. This rebate ($R2_j$) can be shown as a *negative or zero* revenue to the generator, as follows:

$$\text{If } SMP_j \geq S_j, \quad \text{then } R2_j = Q_j \text{ x } (S_j - SMP_j) \quad \text{else } R2_j = 0 \tag{2}$$

Assuming that the Strike Price is never lower than the variable cost of any generator, these expressions defined three different types of half-hour:

[A] $SMP_j < V_j$ In these cases, the output of the generators is zero and so is the rebate required under the reliability option;

[B] $V_j \leq SMP_j < S_j$ Here, the generator is running and earns $R1_j = A_j$ x $SMP_j$, but no rebate is required under the reliability option; and

[C] $S_j \leq SMP_j$ The generator is running and earns $R1_j = A_j$ x $SMP_j$, but the rebated under its reliability option reduces its revenue by the negative amount $R2_j = Q_j$ x $(S_j - SMP_j)$,

In case [C], the generator's total revenue is the sum of two items, ($A_j$ x $SMP_j$) and $Q_j$ x ($S_j$ - $SMP_j$). The generator's total net revenue ($TR_j$) in case C is then:

$$\begin{aligned} TR_j &= (A_j \text{ x } SMP_j) + (Q_j \text{ x } (S_j - SMP_j)) \\ &= (Q_j \text{ x } SMP_j) + (Q_j \text{ x } (S_j - SMP_j)) + ((A_j – Q_j) \text{ x } SMP_j) \\ &= Q_j.S_j + ((A_j – Q_j) \text{ x } SMP_j) \end{aligned} \tag{3}$$

In other words, in half-hours where the SEM Market Price exceeds the Strike Price, the generator receives the Strike Price ($S_j$) for the volume of its reliability options ($Q_j$) and receives or pays the market price ($SMP_j$) for each unit by which its actual output differs from that volume ($A_j – Q_j$).

The SEM Consultation indicates that reliability options are a form of CFD option contract, settled independently of any generator's output, so that the market price for energy continues to provide the incentive to generate.[11] Box 1 explains how such reliability options affect the flow of funds to a generator. For all actual output, the generator receives the SEM Market Price. In those half-hours when the SEM Market Price rises above the Strike Price, the generator has to make a rebate equal to the difference between these prices, leaving it with only the Strike Price for the volume of the reliability options.[12] Hence, for any positive or negative difference between its actual output and this volume, the generator receives or pays the SEM Market Price.[13]

The reliability option denies the generator the opportunity to earn even the market price in half-hours of type [C], by remunerating a certain volume at the Strike Price (which is below the market price, by definition). The reduction in revenue associated with taking on a reliability option defines the minimum fee that a generator will demand in compensation. Box 2 explains how competition will drive down the price of a reliability option, so that it provides just this compensation for the expected loss of this revenue from the market, but no additional revenue.[14]

Reliability options therefore offer additional value above the market price of electricity if and only if the fee for the reliability option exceeds the value of the rebates over the long run. That is unlikely to happen in a competitive market. New England operates a system rather like the one in the SEM Consultation, although it is currently subject to proposals for reform due to the perception that it is failing to provide sufficient incentives. In Britain, early proposals of this type under the Electricity Market Reform have been superseded by a proposal to back up reliability option contracts with an additional penalty, over and above the energy price, for failing to provide capacity. (See section 4 below for further details on these examples.)

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[11] SEM Consultation, Table 10, page 108.

[12] A contract which provides for a "rebate" whenever the market price exceeds the strike price is an option contract, which effectively caps the buyer's net cost of electricity. A contract of this type can also require the buyer to pay a "supplement" to the generator whenever the market price is *lower* than the strike price. A contract which specifies both the "rebate" and the "supplement" is effectively a forward contract which fixes the net price for a fixed volume, regardless of fluctuations in the market price.

[13] This payment of the market price for variations in output preserves the incentive for the generator to produce output when it is efficient to do so, although it still under-remunerates investment in capacity if the market price is capped (explicitly or implicitly). Whether or not the generator is available to generate at its full capacity during half-hours of type C is largely the responsibility of the generator's owners and managers. However, the generator may be less able to respond to the incentive for efficient output, if the price setting rule does not follow a strict "merit order". If the system operator sometimes under-utilises ($A_j<Q_j$) the capacity of generators whose variable cost is below the market price, or overutilises ($A_j>Q_j$) the capacity of generators whose variable cost is above the market price, the revenue received by each generator will be exposed to a kind of "scheduling risk".

[14] In making this statement, we are abstracting from two factors that are important for commercial pricing of reliability options, but which do not affect our appraisal of the value of a reliability option to a generator, namely: (1) any adjustment for the difference in timing between receiving revenues and paying rebates under the reliability optionl; and (2) any premium or discount built into the price of a reliability option to compensate for risk. Since these factors only compensate for the cost of (1) time and (2) risk, they do not alter the conclusion that the price of a reliability option will reflect the costs of fulfilling it.

Thus, in a competitive market the form of reliability option set out in the SEM Consultation will not provide any revenue additional to revenues from sales to the energy market. It will not therefore resolve any "missing money" problem.

If the intended design of a reliability option contract differs from the explanation given above, particularly with respect to the obligations of the provider and penalties for non-compliance, we would welcome a clarification of the proposal and how it differs from capacity auctions and obligations, as well as the chance to consider it in more detail.

## Box 2: Value of a Reliability Option

The total of the rebates due over a year represent the cost of taking on the reliability option. These rebates arise in half-hours of type C (as defined in Box 1) and are zero otherwise (by expression [2]). The total for the year (CRO) is defined as:

$$CRO = \Sigma_j R2_j \qquad [4]$$

The price at which generators are prepared to sell annual reliability options (PRO) can be expressed as the sum of the expected value of this cost, $CRO^e = \Sigma_j R2^e{}_j$, and a net revenue or premium, $D_j$. This price provides the third component of generator revenue:

$$R3_j = PRO = -CRO^e + D_j = - \Sigma_j R2^e{}_j + D_j \qquad [5]$$

In a competitive market, this price will be bid down to the expected cost of the obligation to make rebates under the reliability option, $CRO^e$. The premium, $D_j$, will be zero and $R3_j$ will be equal to *minus* the expected value of the rebates that the generator will have to make after signing the reliability option ($\Sigma_j R2^e{}_j$). (Note that the cost of fulfilling the reliability option is unrelated to the cost of making capacity available.)

Over an extended period, such as a year, the generator's revenue (R) is given by the sum (Σ) of R1, R2 and R3 over all half-hours within that period. Substituting $\Sigma_j R2^e{}_j$ for the revenue from selling the reliability option, $R3_j$, gives the following expression:

$$R = \Sigma_j (R1_j + R2_j + R3_j) = \Sigma_j R1_j + \Sigma_j R2_j - \Sigma_j R2^e{}_j \qquad [6]$$

Expression [6] shows that the reliability option does not provide any additional revenue, over and above what the generator can earn from its sales of energy ($\Sigma_j R1_j$), except to the extent that actual rebates under the reliability option ($\Sigma_j R2_j$) differ from the level of such rebates expected at the time of contract signature ($\Sigma_j R2^e{}_j$). Such differences can be positive or negative, but at the time when capacity is made available, the owners would expect the difference to be zero.

# 3. The Auction Process

We did not consider in detail the revisions to the trading of electricity set out in the SEM Consultation. As discussed above, we assume only that SEM energy prices (PM) will suffer from a "missing money" problem. Under this assumption, average market prices will lie below the cost of new capacity over the long run (i.e. over a whole cycle of surplus and shortage).

The auction process determines the price (PC) that providers can earn for their capacity. We noted in our report that the presence of market power would complicate the design of any CRM to the extent that it relied on trading of capacity in wholesale or retail markets. However, we leave that complication on one side for the purpose of this note and assume that the RAs can enforce competitive pricing in markets for capacity.

### 3.1.1. Impact on prices

The purpose of arranging auctions for capacity four (or more) years in advance is to remove or dampen the price movements caused by temporary surpluses and shortages. In principle, the four year advance notice allows time for the market to equilibrate, so that investors expect year (y+4) to be an "average year". That is a year in which prices settle at the average level, taking account of the average balance between:

(1) years of capacity surplus (when market prices reflect only short run marginal costs of generation – essentially fuel costs); and

(2) years of capacity shortage (when market prices rise above short run marginal costs of generation).

These market prices define the opportunity cost of fulfilling a reliability option.[15] Given the assumption that the RAs can impose competitive pricing in the capacity auctions, competition will drive down the price of a reliability option (PC) for year (y+4) to the level of opportunity cost expected for that year at the time of the auction (i.e. the expected price of electricity in the market in year (y+4) during periods when the option will be called), which we can write as $PM^e(y+4)$.

Sometimes, when year (y+4) comes around, the market will actually face a shortage, and electricity market prices will reach high levels. The possibility of these circumstances arising motivates the imposition of explicit and implicit price caps by regulators and lies at the root of the "missing money" problem.

15 In some hours, a generator will be able to fulfil its obligation by generating electricity from its own resources at a *variable cost* of production which lies below the market price. However, the market price remains the *opportunity cost* of such generation.

Reliability options may mitigate the effect of *implicit* price caps, but only if certain conditions hold:

- *if* all generator capacity is covered by reliability options in the form of a CFD option contract, and
- *if* retail tariffs closely reflect short term electricity market prices, and
- *if* the process of transferring "rebates" to retail customers is closely coordinated with the design of retail tariffs,

*then* the rebates made under reliability options and passed through to customers offset increases in their retail tariffs and hold retail electricity prices stable. Meeting these conditions would require the regulator to coordinate the design of every retail tariff carefully (to reflect current market prices) and the allocation of rebates to final consumers (in proportion to their payment for energy at current market prices).[16] If successful, the effect of coordinating retail tariffs and rebates might diminish the implicit threat of regulatory/political interventions to cap prices. If these conditions hold, prices to customers would not spike at times of shortage and revenues for investment in capacity would be spread instead over a number of periods. However, our report listed a number of other causes of the "missing money" problem in the SEM context:[17]

1. other implicit price caps, e.g. the threat of regulatory intervention for reasons of competition policy when wholesale electricity prices rise;
2. explicit price caps included within the electricity market rules, such as the Bidding Code of Practice and the cap on offer prices;
3. limited demand-side participation, due to transactions costs;
4. "lumpy" investment, meaning that investors require long periods of capacity shortage and (potentially problematic) high prices before they will invest; and
5. the presence of a potentially dominant (and state-owned) player in the wholesale market, increasing the perception that prices are effectively capped.

These other sources of the "missing money" problem mean that the electricity market price expected to emerge in an average year is lower than the Cost Of New Entry (CONE). Hence, as at the date of each auction of reliability options, the expected price for year (y+4) which represents the opportunity cost of fulfilling a reliability option, $PM^e(y+4)$, is less than the CONE. The proposals to reform the New England reliability options refer to some of these remaining problems.

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16 Allocating rebates strictly in proportion to final consumers' actual payments for energy would distort incentives for efficient consumption, which is presumably the reason for setting retail tariffs equal to current market prices in the first place. An efficient allocation of rebates would have to be based instead on some underlying measure of each consumer's *expected* consumption or maximum demand.

17 Shuttleworth et al. (2014), section 3.1, pages 14-15, and appendix A, sections A.2 and A.3, pages 34-43.

To the extent that investors expect the "missing money" problem to depress market prices in year (y+4) below the CONE, the price of a reliability option will reflect those depressed market prices and will not provide any additional revenue to remedy the problem. Each of the factors listed above therefore provides a reason to offer investors additional revenue, through some other kind of CRM.

### 3.1.2. Other arguments

The section above sets out our views on reliability options. The following section anticipates arguments that might be raised in detailed discussion, but which we regard as irrelevant or incorrect.

The existence of vertically integrated companies is sometimes thought to change the way investors approach investment decisions. In some circumstances, investors in vertically integrated company anticipate a future capacity shortage and invest in the capacity required to serve their own anticipated needs (i.e. their forecast of their sales to retail customers), even if anticipated market prices are low. Such investment is a response to the internal opportunity cost of electricity within a vertically integrated company, sometimes known as a "shadow price", when markets are illiquid. In such markets, buyers have little confidence that they can buy large amounts of electricity at the current market price, and so investment decisions are driven by the shadow price instead. Neither the shadow price nor the incentive to invest is affected by the existence of reliability options. The reliability options themselves would not offer any benefits in these circumstances.

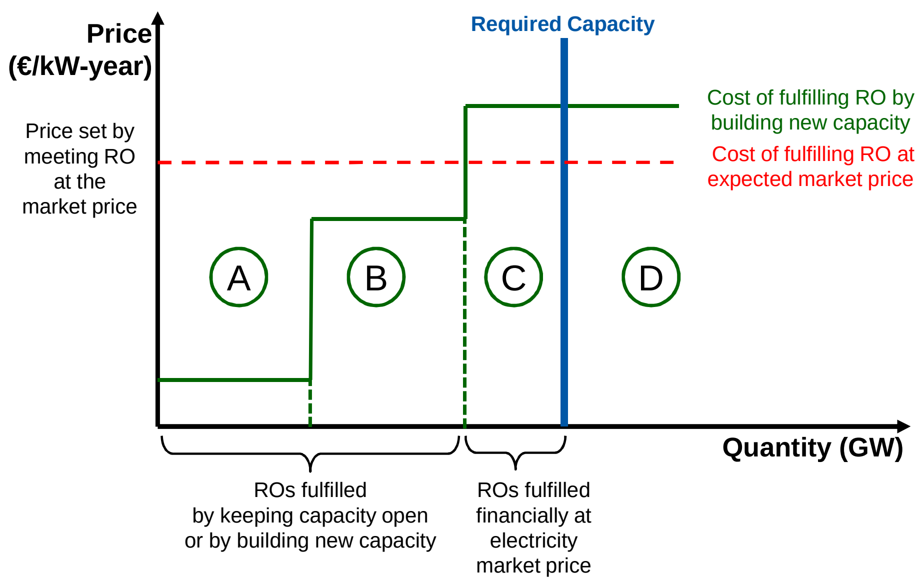
If the electricity market operates in a reasonably liquid manner, and investors anticipate a shortage, one might argue that market prices and the value of reliability options will rise to the CONE. However, that view of the market does not allow for any "missing money" problem and so provides no rationale for reliability options. Occasionally, investors may anticipate a shortage and recognise that new construction is needed (e.g. if the time between the auction and the year of delivery is short relative to the time needed to construct new generator capacity). As long as the opportunity cost of fulfilling an electricity contract or a reliability option is equal to the electricity market price (PM), any constraints on PM will feed through into expectations of PM for year (y+4), and into the opportunity cost of obligations to deliver energy. These constraints will therefore determine both the price of normal electricity contracts for delivery in year (y+4), and the price at which generators offer reliability options for year (y+4).

In years where a shortage is anticipated, some potential providers of (new) capacity may offer capacity priced at the CONE. However, it is not clear that they will sell such capacity at prices higher than expected market price. Such sellers would face competition from other traders prepared to offer contracts at the expected market price which (by assumption) is lower than the CONE. Hence, new entrant costs will *not* drive up the price of reliability options *even if* the total regulatory demand for capacity can only be met by building new plant. Box 3 explains why.

## Box 3: Reliability Option Prices and the Cost of New Entry

In Figure 3.1, the solid blue vertical bar shows the volume of capacity that the regulator would like to have available. The horizontal dashed red line shows the cost of fulfilling a reliability option (RO) as defined in Box 1. The stepped (green) line show four types of capacity and the cost of fulfilling a RO by keeping or making capacity available. Blocks A and Block B are capacity whose avoidable costs are positive, but more than covered by revenue from sales of electricity at market prices (i.e. its cost lies below the dashed red line). Block C is more expensive plant whose costs lie above market revenues (the dashed red line), but the regulator would tolerate these costs to achieve security of supply. Block D is the same kind of plant as Block C, but is surplus to requirements.

**Figure 3.1**
**Electricity Market Prices Determine The Value of Reliability Options**




In these conditions, two factors prevent capacity providers from making Block C available.

First, any providers of capacity who bid the cost of Block C would be undercut by others offering to sign ROs at the cost of fulfilling them by buying energy at the market price.

Second, if any owner of Block C capacity did procure a reliability option at its full cost, it would nevertheless close (or not build) the capacity, because it is cheaper to fulfil the RO by buying energy at the market price.

### 3.1.3. Implications

In certain circumstances, where they are backed up by specific forms of retail market regulation, reliability options can provide a means of stabilising prices to consumers, just like any electricity contract. This effect, if it can be achieved, might diminish the threat of implicit price caps that would otherwise be imposed in response to high retail electricity prices. However, reliability options do not offer any solution to the "missing money" problems caused by other factors such as high wholesale market prices, explicit price caps within electricity market rules, or other imperfections in the electricity market.

The opportunity cost of fulfilling obligations under a reliability option is the electricity market price. If investors anticipate that these factors will depress future electricity market prices, they will depress the cost of fulfilling reliability options, and hence their price in an auction, to the same extent.

If there are other views as to how auctions will set the prices of reliability options, we would welcome a clarification as to how the auction is expected to operate and a chance to consider this explanation in more detail.

# 4. Other Examples of a Reliability Option

The term “reliability options” has been used in other contexts, specifically in the Electricity Market Reform being applied to the British electricity market, and in the current New England electricity market. Below, we describe these mechanisms and how they differ from the reliability options proposed in the SEM Consultation. These examples suggest that it is inadvisable to transfer schemes from other markets without first considering conditions in those markets, and any pressures to change their rules.

## 4.1. British Electricity Market Reform

We note that reliability options were considered in some detail by the British government’s Department of Energy and Climate Change (DECC), in the early stages of the Electricity Market Reform (EMR). Initial documents indicated that (1) the British electricity market suffered from a “missing money” problem due to regulatory and political risk and (2) that reliability options, enforced by the obligation to generator or pay for electricity at a reference price, would provide a more stable revenue stream.

However, in the course of its consultations, DECC seems to have acknowledged that such reliability option contracts would not offer higher or more stable revenue that is already available from contract markets surrounding the current electricity market. As noted in our report, the proposals currently being promulgated by DECC impose a penalty for non-delivery of capacity of £3,000/MWh (€3,600/MWh) *in addition to* the electricity price.[18] This additional penalty injects additional value into the capacity contracts now likely to be offered.

## 4.2. New England Electricity Pool

The New England Electricity Pool currently operates a capacity scheme which is effectively a “centralised reliability option” mechanism. The mechanism is subject to proposals for reform because the system operator believes it does not encourage generators to perform reliably.[19]

The Independent System Operator in New England (ISO-NE) holds mandatory capacity auctions, three and a half years ahead of delivery, with “reconfiguration auctions” to allow adjustments in each subsequent year. The contracts sold in the auction are firm, one-way CFD options against the energy price, and are often called “reliability options”. Generators who hold reliability options receive a fixed revenue set by auction, but must pay a “Peak Energy Rent” (PER) whenever a close-to-real-time energy price rises above the strike price. The PER is equal to the difference

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18 Shuttleworth et al. (2014), section B.2.3, page 51, referring to the **Great Britain CPM Impact Assessment** (2013), pages 32, 69-70.

19 “ISO-NE considers this resource performance problem to be a serious threat to reliability and one that must be addressed in the design of the capacity market” in *Written Comments Of Robert G. Ethier, Ph.D. Vice President Of Market Development, ISO New England Inc*, 30 September 2013, page 7.

between the energy price and the strike price, The current strike price is set equal to the marginal cost of a gas-fired generator with a heat rate of 22,000 BTU/kWh, which is significantly in excess of the costs of any plant currently on the system. Generators holding reliability options must pay the PER *whether or not they are generating* when the energy price rises above the strike price.

This system sounds similar to the "reliability options" proposed in the SEM Consultation. However, the New England scheme contains an additional element. In New England, no investor can claim to offer capacity without verification. Investors wishing to participate in the auction must demonstrate either an actual plant or concrete plans to build plant in a specific location, before being allowed to participate in the auction. The enforcement of this requirement means that the New England scheme contains elements of the "capacity auctions" or "capacity obligations" proposed elsewhere in the SEM Consultation. In New England, the reliability option itself is a measure intended to make regulated utilities contract for energy on a long-term, stable basis.

Retail suppliers in the region are required by regulation to set most retail electricity tariffs in line with the current (short term) electricity market price. In the absence of such a capacity obligation, regulated utilities might choose to buy all their energy from short-term markets, in order to match their cost of supply to the revenue they derive from regulated tariffs. If the large utilities only bought electricity on the spot market, generators would find it difficult to hedge their risks, which could increase their cost of capital. Consumers would also be exposed to all variations in the short term price of electricity. In essence, therefore the New England market for reliability options is an attempt to solve a problem of *missing contracts*, i.e. a lack of long term contracts for electricity, rather than a *missing money* problem, i.e. a lack of revenue.

ISO-NE is currently attempting to replace the system of reliability options in New England because it argues that generators do not have sufficient incentives to provide security of supply, which suggests that there may continue to be a "missing money" problem. The decision on whether to approve the new design of the ISO-NE capacity market rests with the Federal Energy Regulatory Commission (FERC). As part of its submission to the FERC, ISO-NE's expert argued that the incentives to perform provided under the current design were too weak to encourage security of supply and that the new design would provide generators with the "missing money".[20]

Under the ISO-NE's proposal, a new Pay-For-Performance (PFP) programme would replace the PER. The PFP would provide an additional incentive to generate during peak periods, *over and above the energy price*, which would also impart additional value to the associated capacity contracts. Much like the proposed system in Great Britain, the PFP would impose a load-following obligation and would settle imbalances between actual output and the obligated quantity at a penalty balancing price of $5,435/MWh. This amendment would recreate a separate *capacity* obligation and penalty, as distinct from the *energy market* obligations and penalties imposed by reliability options.

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[20] *Testimony Of Peter Cramton On Behalf Of ISO New England Inc.*, September 2013, page 4, 14, 18 and references therein.

# 5. Conclusion

Our understanding of the proposed reliability options is derived from their description in the SEM Consultation. This description implies that they are no different from forward contracts for electricity. The price of such contracts would reflect expectations of future spot prices. Therefore, to the extent that spot prices suffer from the “missing money” problem, so will these reliability options.

We note that the term “reliability options” has been used in other contexts, specifically Britain and New England. In those cases, enforcement of the contracts includes some verification of the capacity being offered or an additional penalty for failing to provide capacity when required. Such enforcement mechanisms are lacking from the reliability options as described in the SEM Consultation and our comments on them reflect this lack. If the proposed reliability option is intended to include some enforcement of the capacity obligation, as well as an obligation to make up deficiencies at the energy price, we would welcome a clarification of the proposal.

However, adding such an enforcement mechanism would make the reliability options similar in principle to the proposed capacity auctions or capacity obligations, in which case they would be a redundant proposal.

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