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DAY-AHEAD MARKET COUPLING OPTIONS FOR THE SEM

A report to the Commission for Energy Regulation and the Utility Regulator

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EXECUTIVE SUMMARY AND CONCLUSIONS

Purpose of this document

Pöyry has been appointed by the Regulatory Authorities to provide advice on the options for the development of a day-ahead trading solution for the SEM. The SEM Committee has specified that the options for the day-ahead trading solution should:

- allow a day-ahead coupling of the SEM and neighbouring markets that is compatible with the requirements set out in the draft Framework Guidelines[1] that are expected to be incorporated into a legally binding European network code early next year; and
- not fundamentally alter the SEM rules.

In this Executive Summary, we:

- describe the context for day-ahead trading in the SEM;
- discuss the key design requirements;
- identify six conceptual options;
- summarise the results of our high-level assessment of each option;
- set out our preliminary recommendation with respect to these options; and
- highlight other issues for consideration in developing a day-ahead trading solution.

Context

In September 2009, the SEM Committee issued a consultation on the integration of the SEM with other European markets[2]. In this document, the SEM Committee described maximising the efficiency of interconnection capacity between the SEM and neighbouring markets as a key objective. It also noted the need to comply with European law.

Based on the responses to that consultation, the SEM Committee decided to explore the development of a loose form of *volume coupling*[3] between the SEM and other European markets at the day-ahead stage, while taking forward a separate project on within-day trading[4].

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1 'Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (Ref: E10-ENM-20-03)', 8 September 2010, issued by ERGEG in place of ACER.

2 'SEM Regional Integration. A Consultation Paper. SEM-09-096', 10 September 2009, CER and Utility Regulator.

3 Under volume coupling, day-ahead interconnector flows are set in a process which mimics calculation of market prices in the adjacent markets, based on bid data from the local markets and a simple pricing algorithm, but prices are then calculated in the separate markets using the local pricing algorithms. As a result, when the local market prices are calculated, the interconnector flow may not be efficient. Volume coupling is 'loose' or 'tight' depending on the degree to which the volume calculation mimics the precise pricing algorithm (e.g. block bids, ramp rates) in the local markets.

4 'SEM Regional Integration. Consultation Paper Responses and SEM Committee Decision. SEM-10-011', 3 March 2010, SEM Committee.

Over the past year, the European debate on market coupling has placed a much stronger emphasis on day-ahead *price coupling*[5]. This forms part of the target model for market integration as set out in the draft Framework Guidelines on capacity allocation and congestion management ('Framework Guidelines') issued by the European regulators in September 2010.

The principles set out in the Framework Guidelines are expected to be incorporated by ENTSO-E[6] into a legally binding European network code for day-ahead markets by Q1 2012. Under the proposed timetable for the development of market coupling, the SEM is expected to join the day-ahead price coupling arrangements by around 2014.

There are also two industry-led initiatives to deliver day-ahead price coupling by the end of 2012 for the neighbouring markets to the SEM (including BETTA and the CWE market[7]).

The key challenge for the SEM is that its market design is fundamentally different from the approach used in the rest of North West Europe, with the latter having strongly influenced the design of the Framework Guidelines and market coupling initiatives. To a large extent, these differences reflect the particular challenges that a small, relatively isolated island system like the SEM faces in maintaining a secure supply and mitigating market power.

Requirements of common price coupling solution

A key requirement of the Framework Guidelines is the delivery of a day-ahead market that provides firm quantities and prices, i.e. in the form of day-ahead agreements which are (financially) firm on both buyers and sellers

In this context, we propose (subject to detailed legal interpretation) that 'firm' means that if one party fails to fulfil its contract **for reasons that fall within its responsibility**, then it must ensure that the other party is held whole (including through financial recompense where appropriate, whether directly or indirectly).

On first sight, this could be structured as a day-ahead CFD around the ex-post SEM market price. The ex-post schedule and the process of dispatch would not take into account the results of the day-ahead market, but would continue to operate as in the present SEM.

However, a CFD of this form exposes participants in the day-ahead market in the SEM to something akin to an imbalance risk that takes the form of exposure to the ex-post price for the differences between the day-ahead contracted quantities and the volumes in the ex-post schedule[8]. Given that the ex-post schedule is calculated in a centralised optimisation process, with restrictions on generator bidding, participants are not able to manage their exposure to this risk.

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5 Under price coupling, day-ahead prices and firm contracts in each market are set jointly with interconnector flows in a simultaneous process.

6 European Network of Transmission System Operators for Electricity.

7 The Central Western European Market Coupling (CWE) includes Germany, France, the Netherlands, Belgium and Luxembourg.

8 In practice, the commercial position for a market player under a CFD with ex-post settlement of a gross pool is equivalent to its position in a physical day-ahead market with an ex-post imbalance price applied to residual volumes.

This means that if an Irish generator strikes a day-ahead contract and is subsequently excluded from the ex-post schedule for reasons for which it is not responsible (e.g. change in total demand), then the CFD does not offer the generator any means for protecting its commercial position.

Therefore, in order to meet the principles of 'firm' trades, we believe (subject to detailed legal interpretation) that an additional mitigating mechanism needs to be introduced to protect market participants against certain 'imbalance' risks that fall outside their own responsibility.

Consistency with the existing SEM design

We designed options for a day-ahead market around the requirement not to fundamentally alter the SEM rules, with reference to the High Level Principles of the SEM market design[9]. The market design is based around the operation of an ex-post gross mandatory pool with central commitment[10].

There are also a number of more detailed features of the ex-post market set out in the High Level Design, each of which are followed (with respect to the ex-post market) within our proposed options:

- single system marginal price (SMP) for each half hour based on an ex-post optimised schedule for the whole day;
- gate closure suitably long in advance of real time;
- complex bids from generators;
- indicative and real time dispatch schedule based on most accurate demand forecast, wind generation forecast, reserve requirements, transmission constraints and generation availability;
- single price for the island;
- payments for transmission constraints;
- de minimis level for compulsory participation of generation;
- provisions for renewable generators to be treated as price-taking volumes in the ex-post schedules; and
- explicit capacity mechanism.

9 'The Single Electricity Market (SEM). High Level Design Decision Paper. AIP/SEM/42/05.' 10 June 2005, CER and NIAER.

10 In this context, we have interpreted 'centralised commitment' as referring to centralised optimisation of the ex-post schedule.

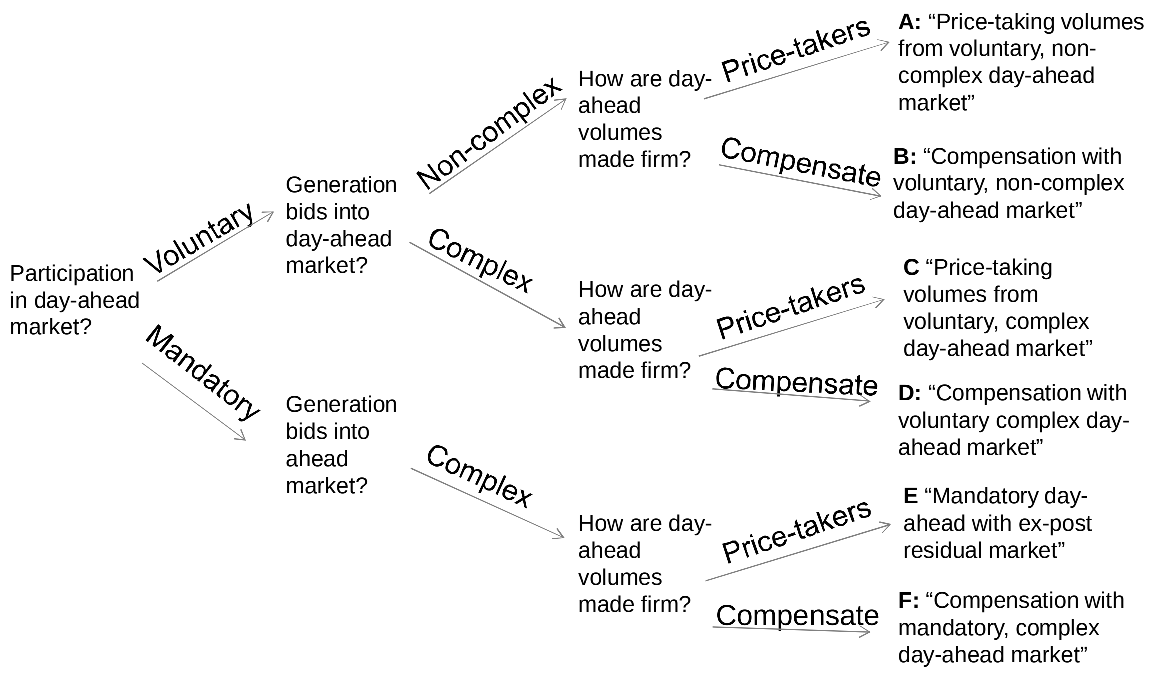
Options

We have developed six conceptual options for a day-ahead trading solution. We believe that all of these options are compliant with European requirements (subject to detailed legal interpretation), and the maintenance of the high-level principles of the SEM design.

Figure 1 summarises how we have developed our options the answers to three key questions:

- **Should participation in the day-ahead market be mandatory or voluntary?**
- **What is the form of generation bids into the local day-ahead market?** – either market participants take responsibility for creating non-complex bids for use in the day-ahead market[11], or their complex bids are converted to non-complex bids by a centralised agent.
- **How are day-ahead volumes made firm?** – either by being treated as price-taking volumes in the ex-post schedule or through compensation payments (where appropriate) for differences between day-ahead and ex-post volumes.

Figure 1 – Overview of options for day-ahead trading solution in SEM



In option E, the day-ahead prices are made firm through settlement of the day-ahead market with imbalance payments for residual differences in volumes in the ex-post market. In the other five options, the Irish day-ahead market is a CFD market with settlement in the ex-post market. In practice, the choice between these two approaches does not directly affect the commercial position of market participants.

11 We have assumed that where the day-ahead market is mandatory, then complex bids will be submitted by participants.

Assessment of options

We have assessed each option using the following list of criteria, which are based on the TSC objectives, with the addition of an explicit requirement for compliance with European developments:

- **promotion of competition;**
- **efficient administration of the SEM**, including cost of implementation;
- **efficient ex-post pricing,** reflecting the TSC objective regarding costs to consumers;
- **opportunities for risk management**, reflecting the TSC objective regarding costs to consumers;
- **size of constraint and compensation payments**, reflecting the TSC objective regarding costs to consumers; and
- **compliance with European development** (subject to detailed legal interpretation).

Table 1 presents a summary assessment of the performance of the six different options against the following scoring criteria:

- ✓ policy option clearly performs well against objective;
- (✓) policy option has some positives for objective;
- \- policy option has no material impact on objective;
- (×) policy option has some negatives for objective; and
- × policy option clearly performs badly against objective
- ×× policy option performs very badly against objective

The summary assessment highlights that the different options have strengths and weaknesses in different areas, with no option performing well against all criteria.

Table 1 – Summary assessment of options

Assessment criteria	A	B	C	D	E	F
Promote competition	-	-	(✓)	(✓)	✓	✓
Efficient administration of the SEM	✓	(✓)	(×)	×	××	×
Efficient ex-post pricing	(×)	(✓)	(×)	(✓)	×	(✓)
Opportunities for risk management	(✓)	(✓)	✓	✓	(✓)	(✓)
Size of constraint and compensation payments	(×)	(×)	×	×	(✓)	×
Compliance with European developments	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)

Preliminary recommendation for day-ahead trading solution

Our preliminary recommendation for the day-ahead trading solution is Option B 'compensation for changes from a voluntary day-ahead market based on non-complex bidding'. We now summarise how Option B addresses each of the three design questions before describing how Option E may be an attractive alternative in the long-term.

Should participation in the day-ahead market be voluntary or mandatory?

Option B introduces **a voluntary day-ahead market.** This would enable market participants, including suppliers and price-taking generation, to decide (as in other European markets) whether or not the day-ahead market is attractive.

What should be the form of generation bids into the local day-ahead market?

Option B places the **responsibility on generators for converting complex SEM bids into non-complex bids for the day-ahead market**. This is consistent with the designation of a voluntary day-ahead market, as market participants can choose whether or not they want to take on this responsibility.

How are day-ahead volumes made firm?

In Option B, **day-ahead volumes are made firm through the use of a compensation payment** made to keep market participants whole with respect to volume risks for which they are not responsible.

This means that the day-ahead market result does not restrict the optimisation carried out for the ex-post schedule. Therefore, the ex-post schedule can (as now) fully represent the complex bids of the Irish system and take into changes after the day-ahead stage, including within-day bids. Consequently, there should be no increase in the divergence between the ex-post schedule and actual dispatch[12] (and hence constraint payments), providing reward to flexible generation that for example can respond to changes in wind and demand from the day-ahead forecast.

The implementation of this option would require detailed work to clearly define the circumstances under which a compensation payment would be made. These definitions would need to be informed by detailed legal interpretation of what the EU requirement for firmness.

Alternative option – Option E

We think that Option E ('mandatory day-ahead with ex-post residual market') may also be an attractive option, as it would by definition, deliver a highly liquid day-ahead market. However, this option would require **frequent** opportunities for within-day rebidding, as this would reduce the exposure of suppliers and price-taking generation in a mandatory market to differences between day-ahead and ex-post volumes. This means that it may not be appropriate at this stage because significant further changes would be needed to the mechanics, if not necessarily the spirit, of the intra-day gate closures set out in the proposed intraday modification.

12 Dispatch is assumed to continue to be on a least-cost basis.

Other issues

There are a number of other issues that will affect the development of a day-ahead trading solution but fall outside the scope of our high-level options. The following issues are of particular importance:

- allocation of long-term interconnector capacity rights;
- creation of comparable bids and offers; and
- timescale for introduction of day-ahead solution.

Allocation of long-term interconnector capacity rights

The Framework Guidelines allow for long-term[13] interconnector capacity rights to be physical or financial, with the latter giving the holder no right to submit a bid (or nomination) for use of the interconnection capacity. Therefore, the availability of interconnection capacity for day-ahead market coupling will be determined by:

- the physical interconnection capacity[14];
- the amount of long-term physical rights allocated (if any); and
- the residual capacity available, after nomination against the physical capacity rights (if any) prior to the day-ahead market coupling.

Under the current SEM rules, a physical right gives the capacity holder a right to submit a bid for use of interconnection capacity not (as in other markets) to unilaterally declare a flow against that capacity. Consequently, the use of interconnector bids is determined by a run of the ex-ante schedule, which will need to be maintained if physical capacity rights are retained.

The flows determined by the existing process are based on a full representation of the Irish markets through mandatory participation and complex bids, and take into account interconnector losses. However, this run of the ex-ante schedule only represents the market in GB to the extent that parties hold long-term interconnector capacity rights and bid the expected GB price[15] into the SEM at the day-ahead gate closure.

Under the day-ahead market coupling, the interconnector flows determined by the central coupling algorithm will be influenced by all bids received in the entire day-ahead market in GB. However, the central coupling algorithm has a less complete representation of the Irish market than the ex-ante schedule because it uses non-complex bids (and participation could be voluntary).

Therefore, the decision on the balance between physical and financial long-term capacity rights needs to take into account the relative strengths and weaknesses of these two approaches to determining interconnector flows.

The RAs would also need to consider the need for compliance with the Framework Guidelines, particularly whether this would be satisfied by the allocation of all

13 ‘Long-term’ means any period longer than a day, ranging from a week out to multi-year holdings.

14 Under the Framework Guidelines and current SEM rules, available transfer capacity should be defined in relation to the physical availability of the interconnector equipment (i.e. ignoring any local transmission constraints).

15 Allowing for capacity payments and other variable (non-energy) costs.

interconnection flows through an ex-ante schedule, which left only the residual capacities (and reverse flows)) for the day-ahead market.

Comparable bids and prices

In order to produce an efficient market coupling result, then the bid and offer prices in all coupled markets must be for a comparable product. We believe that all bids into the central market coupling algorithm should cover both energy[16] and capacity, as this is consistent with the approach in the other European markets.

Otherwise, if for example, SEM bids only cover energy, the resulting day-ahead price in the SEM will be artificially low, and the SEM will be subsidising the export of both energy and capacity to adjacent markets.

Our initial view is that a central agency in the SEM would be responsible for adding an allowance for capacity payment forecast to the bids received. This would be the case even if the generators were submitting non-complex bids. The detailed mechanics of this have not been explored, but are likely to require some form of rules to be developed for how this is achieved by the central agency.

Timescale for introduction of day-ahead trading solution

There are a number of potential benefits from rapid introduction of a day-ahead trading solution in the Irish market. It would help Irish consumers to benefit earlier from the expected benefits of day-ahead market integration; such as:

- more efficient scheduling and use of interconnection at the day-ahead stage;
- improved risk management for participants (including the demand side); and
- increased competition in the Irish electricity market.

A day-ahead price coupling covering the Nordic market, BETTA and the CWE market[17] is scheduled for 2012. Even if the SEM is not able to be included in the coupling at launch, progress towards a day-ahead solution for the SEM would give the RAs and other SEM parties the greatest opportunity of influencing the design of those price coupling arrangements.

However, delaying the introduction of a day-ahead trading solution for the SEM would allow time for the intra-day arrangements to be bedded in before making more major and costly changes to market systems. Furthermore, the Framework Guidelines and target model suggest that day-ahead price coupling arrangements across Europe does not need to be in place until 2015, with the SEM not expected to join until 2014.

A key consideration in the definition of an appropriate timescale will be the cost and time needed to implement any system changes. Therefore, understanding this will be an important part of the development of more detailed options for the day-ahead trading solution.

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16 Inclusive of start and no load costs as far as is possible.

17 The Central Western European Market Coupling (CWE) covers France, Belgium, the Netherlands, Germany and Luxembourg.

1. PURPOSE AND STRUCTURE OF THIS REPORT

1.1 Introduction

Pöyry has been appointed by the Regulatory Authorities to provide advice on the options for the development of a day-ahead trading solution for the SEM. The SEM Committee has set requirements that the day-ahead trading solution should:

- allow day-ahead coupling of the SEM and neighbouring markets that is compatible with the common price coupling solution being developed at a European level; and
- not fundamentally alter the SEM rules.

This paper is based on work carried out by Pöyry Management Consulting and YellowWood Energy in conjunction with the Regulatory Authorities (RAs) in the second half of 2010.

1.2 Structure of this report

The structure of the remainder of this paper is as follows:

- Chapter 2 sets out the key requirements of the day-ahead market coupling arrangements described in the Framework Guidelines.
- Chapter 3 reviews the differences between the design of the SEM and its neighbouring electricity markets.
- Chapter 4 describes six conceptual options for a day-ahead trading solution that we believe are compliant with respect to both the European requirements (subject to detailed legal interpretation), and the high-level principles of the SEM design.
- Chapter 5 provides a high-level assessment of the six options.
- Annex A gives more details on the proposed initiatives for European market coupling, particularly with reference to the ones expected to affect the SEM's neighbouring markets.
- Annex B describes the key features of price and volume market coupling.
- Annex C makes a detailed comparison between the design of the SEM and the key features of its neighbouring markets (in aspects relevant to the day-ahead design).
- Annex D sets out the terms of reference for this report.

1.3 Conventions

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Management Consulting.

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2. EUROPEAN MARKET COUPLING REQUIREMENTS

This chapter describes the market coupling requirements and our view on their interpretation:

- evolution of the proposed market coupling arrangements including timing (with further detail at Annex A);
- a description of the key requirements of the proposed market coupling arrangements which the SEM is expected to adhere to; and
- our interpretation of the key principles, for example relating to the definition of 'firm'.

The concepts of price and volume market coupling are discussed in this chapter but are described in more detail in Annex B.

2.1 Evolution of the proposed market coupling arrangements

Recent years have seen a drive towards greater integration of European electricity markets at the day-ahead stage. Over the past year, the focus of European discussions on day-ahead market integration at the have moved to a much stronger emphasis on *price coupling* (in which day-ahead prices in each market are set jointly with interconnector flows).

The European regulators issued draft Framework Guidelines on capacity allocation and congestion management ('Framework Guidelines') in September 2010[18]. These will inform legally binding network codes that will be developed by ENTSO-E over the next two to three years. A network code will be developed for each of the four objectives set out in the Framework Guidelines:

- 'to ensure optimal use of transmission network capacity in a coordinated way' (through appropriate mechanisms for capacity calculation and definition of zones);
- 'to achieve reliable prices and liquidity in the day-ahead capacity allocation';
- 'to achieve efficient forward market'; and
- 'to design efficient intraday market capacity allocation'.

The network codes for day-ahead and intraday are expected to be developed first with finalised versions scheduled to be issued by Q1 2012. The development of the network codes covering the forward market and capacity calculation will happen a little slower, with completion of the final version of these code scheduled for Q3 2012.

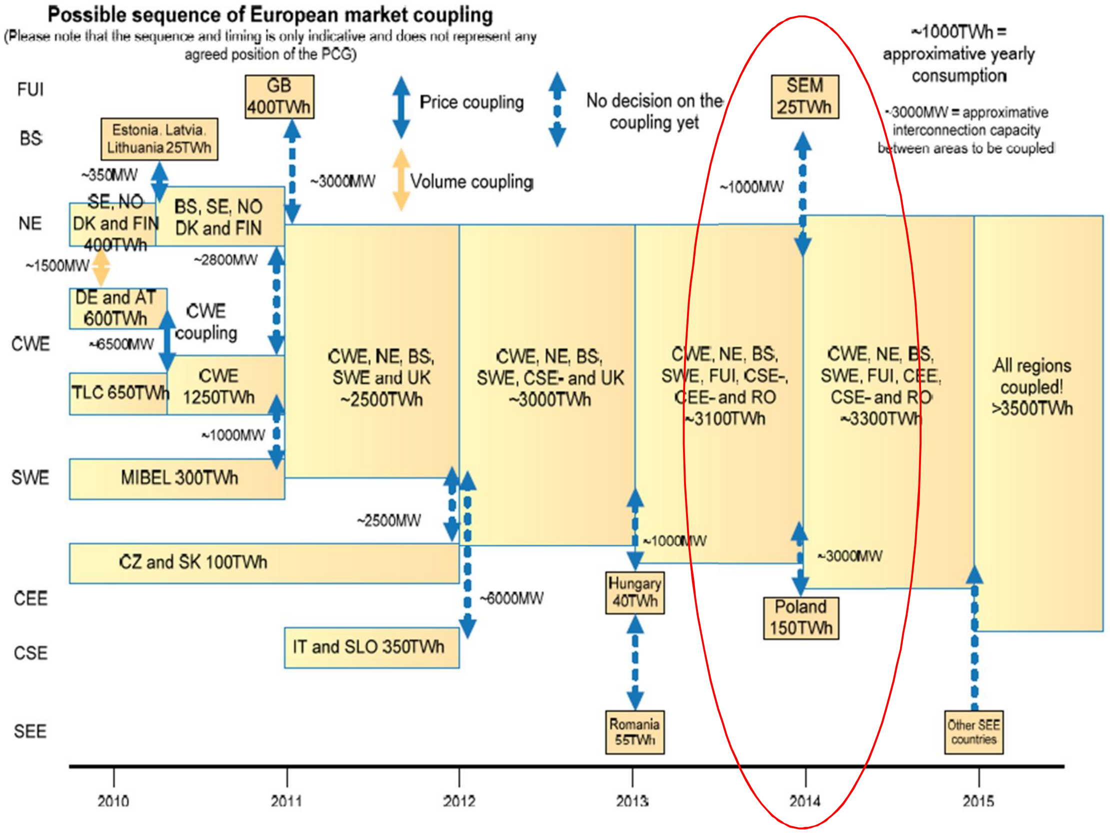
The options in this report are designed to be compliant (subject to detailed legal interpretation) with the requirements of the Framework Guidelines, which are expected to be embodied in the day-ahead network code.

The day-ahead requirements are centred on the delivery of day-ahead price coupling across Europe, building on the target model for market integration. Figure 2 illustrates the expected timeline for the development of day-ahead price coupling under the target model. Under this timeline, day-ahead price coupling is expected to be implemented

18 'Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (Ref: E10-ENM-20-03)', 8 September 2010, issued by ERGEG in place of ACER.

across all EU markets by the end of 2015[19], with the SEM participating from around 2014. As the details of the price coupling arrangements are yet to be resolved, early engagement in the process by the Regulatory Authorities (RAs) may give them the greatest opportunity to influence the detailed design.

Figure 2 – Intended sequence for EU market coupling



Source: 'PCG Report to the XVIIth Florence Forum, 10&11 December 2009, Rome'

Annex A provides further detail on the evolution of day-ahead coupling arrangements covering the Nordic market, BETTA (in GB) and the Central Western European (CWE) market (which includes Germany, France, Belgium, Luxembourg and the Netherlands).

2.2 Requirements of Framework Guidelines

The draft Framework Guidelines support a drive towards a European target model for day-ahead market coupling based around:

- price coupling;
- the submission of compatible bids/products across countries;
- sharing of all bid data between power exchanges; and
- harmonised gate closure times.

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19 On 4 February 2011, a European Council (Heads of Government meeting) on energy called for the completion of the single market for electricity by 2014 (a year ahead of the Commission target).

Under price coupling, there is a single pricing algorithm that jointly determines market prices, generation volumes and interconnector flows (for the capacity given to day-ahead market) for each coupled market

This drive towards day-ahead market coupling is supported by a number of detailed provisions including:

- 'The TSOs, in cooperation with PXs…(shall) implement capacity allocation on the basis of implicit auctions via **a single price coupling algorithm which determines at the same time volumes and prices in all relevant zones**' (Section 2.1);
- 'Accepted implicit[20] day-ahead trades shall be firm after gate closure[21]' (Section 2.5);
- 'The algorithm shall allow for block bids' (Section 2.1); and
- 'the day-ahead electricity price (shall be) based on the marginal pricing principle' (Section 2.3)[22].

The specification of firm day-ahead trades reflects prevailing arrangements in NWE electricity markets but is not a concept that currently exists in the SEM.

There are alternatives to price coupling mentioned in the Framework Guidelines but they are generally seen as either a temporary option, in the case of volume coupling[23], or as a last resort in the absence of liquid price signals (retention of explicit auctions at day-ahead stage).

2.3 Interpretation of the key requirements for market coupling

Based on the draft Framework Guidelines, we have identified the following requirements which will need to be met by an Irish day-ahead market:

- price coupling;
- common gate closure times;
- common bid format;
- comparable prices;
- participation of buyers and sellers;
- liquid and reliable day-ahead market; and
- firm day-ahead trades.

All interpretations set out in this document of the requirements of the Framework Guidelines and what would constitute 'compliance' are the opinion of Pöyry, and should be subjected to legal review before reliance is placed upon them.

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20 In an implicit auction, the price of interconnection capacity, the all-in energy price in each market and interconnection flows are determined simultaneously. Therefore, market participants do not need to separately buy (explicit) interconnection capacity.

21 We interpret this as referring to the gate closure for the day-ahead market.

22 This is clarified in the Initial Impact Assessment (IIA) on the Framework Guidelines, which states that "pricing should usually reflect the variable costs of marginal generation plant" (pg 43).

23 Although the IIA on the Framework Guidelines does state that 'the efficiency of tight volume coupling may be very close to price coupling' (pg 46).

2.3.1 Price coupling

The essential characteristic of price coupling (as set out in Annex B) is a simultaneous calculation of prices and volumes across several markets by a 'price coupler' which operates at a trans-national level. As a result, any detailed pricing rules of each local market will not be fully recognised in the day-ahead calculations.

As price coupling is based on an implicit auction, the price of interconnection capacity, the day-ahead price in each market and interconnection flows are determined simultaneously. Therefore, market participants do not need (and indeed cannot) to separately buy (explicit) interconnection capacity for use at the day-ahead stage.

2.3.1.1 Available interconnection capacity for price coupling

The Framework Guidelines allow for the existence of long-term[24] interconnector capacity rights, which can be physical or financial.

Physical rights give the holder the right to nominate a flow, or in the case of the SEM, an intended flow against its capacity holding. Under the existing congestion management guidelines, any 'unused' physical capacity holdings must be released at the latest by the gate closure for the day-ahead market – this is normally described as a 'use it or lose it (UIOLI) provision.

The draft Framework Guidelines set out 'use-it-or-sell-it' (UIOSI) arrangements for physical capacity rights at the day-ahead stage. Capacity holders who do not use their capacity receive revenue based on the price differential between the two interconnected markets (assuming there is congestion/a price differential and that the flow is in the same direction as their capacity holding).

A financial right means that a capacity holder (normally) receives revenue on the same basis as unused physical capacity holdings. However, the capacity holder has no preferential access to the physical capacity, and the full interconnection capacity is put into the day-ahead market coupling process.

This means that the availability of interconnection capacity for day-ahead market coupling will be determined by:

- the physical interconnection capacity[25];
- the amount of long-term physical rights allocated (if any); and
- the residual capacity available, after nomination against the physical capacity rights (if any) prior to the day-ahead market coupling.

The Framework Guidelines state that (as is currently the case under the SEM) available transfer capacity should be defined in relation to the physical availability of the interconnector equipment (i.e. ignoring any local transmission constraints). At the EU level, this requirement seeks to ensure that the maximum amount of interconnection capacity is available for the day-ahead market coupling. Consequently, intra-market local transmission constraints should not be transferred to market (usually country) boundaries.

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24 'Long-term' means any period longer than a day, ranging from a week out to multi-year holdings.

25 Under the Framework Guidelines and current SEM rules, available transfer capacity should be defined in relation to the physical availability of the interconnector equipment (i.e. ignoring any local transmission constraints).

2.3.2 Common gate closure times

The proposed timings in the day-ahead market coupling process in North West Europe include a gate closure at 12.00 CET day-ahead (11am Irish time) with a turn-around of results within one hour. The trading day in the CWE markets is for a 24 hour period (one hour intervals) starting at midnight CET (11pm Irish time).

In support of market transparency, current practice in Nordpool and in the CWE markets is for the TSOs to release the available interconnection capacity to the day-ahead coupling 90 minutes ahead of the day-ahead gate closure.

2.3.3 Common bid format

The price coupler will accept a common set of bid formats (whose details are currently under discussion). Although provision is made for 'block bids', these are unlikely to encompass the full complexity of technical and commercial offer data used in the SEM.

The operator of each day-ahead market would gather bids and offers from local generation and demand. They would then be responsible for providing bids and offers in an acceptable form to the central market coupling algorithm. We have assumed that the market coupling algorithm will accept the following type of bids and offer from the local market operator:

- an aggregated bids and offer curve for all simple bids; and
- (anonymised) block bids that can be directly passed on from market participants.

Local day-ahead market operators however have flexibility over what bids they accept from market players. The types of bid currently accepted by power exchanges in various European countries include (see Annex C, Section C.2.2 for further detail):

- a simple bid, which covers the operation of the generator in a single hour;
- standard block bid (combining bid prices and volumes for a consecutive number of single hours);
- profiled block bid (quantity differs across hours);
- maximum payment conditions (buy side) or minimum income conditions (sell side); and
- linked block bids (whether complementary or mutually exclusive).

2.3.4 Comparable prices

In other European markets, the price produced by a market coupling process will be an 'all-in' price (e.g. covering both energy and capacity). The ex-post price in the SEM includes an explicit capacity payment and a separate energy price, which is called the system marginal price (SMP). The SMP covers variable production costs, including start-up and no-load, and may in turn be separated into the shadow price and an uplift element.

In order to produce an efficient market coupling result, then the bid and offer prices in all coupled markets must be for a comparable product. We believe that all bids into the central market coupling algorithm should cover both energy[26] and capacity, as this is consistent with the approach in the other European markets.

Otherwise, then the SEM bids and the resulting day-ahead price (in the SEM) will seem artificially low from the perspective of the market coupling. Consequently, the SEM will be subsidising the export of both energy and capacity to adjacent markets.

Both France (under the NOME law) and GB (under the EMR proposals) are proposing to introduce more explicit capacity mechanisms into their market design. However, these capacity mechanisms will not necessarily be based around a separate capacity payment for the whole market as in the SEM. For example, the capacity mechanism in France may be based around a capacity obligation on suppliers. Therefore, we believe it is appropriate that prices should be matched on an all-inclusive basis.

The Electricity Market Reform (EMR) proposals for BETTA discuss the introduction of a targeted capacity mechanism (CPM). However, the stated intention is that the energy-only price formation within the wholesale market will be retained, and there will be an attempt to prevent the targeted CPM from influencing imbalance, spot or forward prices.

2.3.5 Participation of buyers and sellers

The nature of the day-ahead market is that both buyers and sellers participate actively in terms of submitting firm pricing offers and bids. For the market to be successful, suppliers (or some representative body) must actively submit priced bids and accept firm contracts as a result.

2.3.6 Liquid and reliable day-ahead market

In order to be considered compliant with the Framework Guidelines, we believe that the day-ahead market must deliver a credible level of liquidity in order to provide a reliable price, and efficient day-ahead interconnector flows.

In practice, market liquidity can never be guaranteed by those designing the market, but at least the design must not contain significant impediments to its use by participants.

A key aspect of this is the allocation of risk arising from differences between the day-ahead and ex-post markets. Day-ahead participants should not be exposed to unmanageable commercial risks (e.g. if their day-ahead volumes are not respected in the ex-post schedule and they are left facing the associated risks), otherwise participation levels will be reduced.

The criteria for assessing whether or not a day-ahead market is liquid have been discussed in the RAs' review of market power and liquidity in the SEM[27] and in Ofgem's analysis of GB wholesale electricity market liquidity[28]. These reviews suggest two ways of measuring the level of participation in the day-ahead market:

- volume of generation in day-ahead auction as a percentage of consumption; and
- number of players in day-ahead auction.

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26 Inclusive of start and no load costs as far as is possible.

27 'Market Power and Liquidity in the SEM. A report for the CER and for the Utility Regulator', Cambridge Economic Policy Associates, 15 December 2010.

28 'GB wholesale electricity market liquidity: summer 2010 assessment', Ofgem, July 2010.

2.3.7 *Firm trades*

Compliance with the Framework Guidelines requires day-ahead contracts to be offered which result in firm prices and quantities. The introduction of firm day-ahead contracts would allow some participants to manage their risks better, and for example might be better suited to the inclusion of demand side management in the market.

The definition of 'firm' merits discussion. In our view, this does **not** require that those prices and quantities must be respected within the ex-post market schedule. Instead, we propose that 'firm' should be interpreted to mean that if one party fails to fulfil its contract **for reasons that fall within its responsibility**, then it must ensure that the other party is held whole (including through financial recompense where appropriate, whether directly or indirectly).

A few examples illustrate our initial view of the application of this principle, from the perspective of a generator or supplier which has struck a firm day-ahead contract. In all of these examples, we assume that the SEM continues to deliver an ex-post price and scheduled quantity for the entire market which may not (entirely) respect the day-ahead quantities. The examples each assume that there is a single cause for change between the day-ahead and the ex-post market. In practice such differences will arise from a combination of causes, which will require significant analysis when we reach the detailed design stage.

- If the plant availability falls, meaning that the contract volume cannot be fulfilled, then the generator should be liable for the cost of procurement of replacement power (e.g. at the ex-post SMP).
- Differences between the day-ahead and ex-post scheduled quantities which arise from changes by the generator of its submitted bid price should be at the risk of the generator.
- If a supplier chooses to buy a volume of energy at a day-ahead price, and its customers consume less energy than it has chosen to buy, then it should be exposed to the ex-post price for the re-sale of that energy (which is akin to an imbalance risk).

To the extent that the day-ahead contracts cannot be fulfilled due to matters which are not the responsibility of either party (for example design differences between day-ahead and ex-post markets or the actions of a central agent), the principles are less clear.

One view is that compensation should be paid to hold both parties whole, with this compensation being funded by a broader set of market participants[29]. We set out examples below which apply this view:

- Where the generator submits complex bid data to a central agency, which in turn converts the information to a non-complex bid for use by the central market coupling algorithm, then the generator should be compensated for differences between the day-ahead and ex-post scheduled quantities to the extent that they arise from the simplification of its bids.

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29 For example, the compensation risks arising from a central agent converting complex into non-complex bids could be recovered from all day-ahead market participants, all generators, or even all generators based on the difference between their incremental and all-inclusive bids.

- Where a supplier is allocated a demand forecast by a central agent for use in the calculation of its firm day-ahead contracts, then the supplier should not be held responsible for forecast errors. (A similar issue applies for generators, such as wind plants, that are currently treated as price-taking generation in the SEM).
- If the ex-post scheduled quantity for the generator is less than the contracted quantity due to a change in the balance of supply and demand (e.g. a reduction in system demand or an increase in wind compared with expectations at the day-ahead stage), then the generator should be held whole to the (net) revenue that it expected to earn based on the day-ahead contract round.

If prices in a voluntary day-ahead market are systematically above or below the ex-post SEM prices more generation and/or demand is likely to move to that market. Naturally, the prices in the two markets should then tend to converge (allowing for the increased or decreased risk exposure associated with contracting forward). Therefore, there is an argument that in a voluntary market, any risks which arise from design differences should not be compensated, since the participants were not obliged to trade day-ahead. However, this may impair the level of market liquidity if these risks are seen to be unmanageable by market participants. Conversely, if the day-ahead market is compulsory then it would seem unreasonable for individual participants to be exposed to costs arising from design differences.

3. DESIGN FEATURES OF SEM AND OTHER NWE MARKETS

This chapter discusses aspects of market design, including how the design of the SEM and other North Western Europe markets differ. Further detail is provided in Annex C.

3.1 Challenges for electricity market design

There are a number of common challenges that must be addressed by the design of any electricity market:

- the electricity system must be operated within narrow frequency and voltage limits, and there is very **limited scope for storage**, so **generation must equal demand in real-time**;
- electricity is transported over a shared network, and hence **actions by any party can impact on others**;
- **parties cannot be forced to act in accordance with prior contracts**, which creates potential for unexpected behaviour and need for actions to be taken to balance the system;
- **demand is highly variable** (e.g. in response to time of day, season and weather) **but** is relatively **insensitive to price**; and
- society has come to expect a reliable electricity supply, and **the cost of supply interruptions is high**.

Taken together, the above features mean that there is a greater need for spare capacity to meet peak demand, to respond to unexpected actions and to maintain system security compared with virtually any other traded commodity.

Despite these common challenges, there are a variety of electricity market designs in use across the world reflecting local issues, objectives and philosophies.

3.2 Design of SEM and other NWE markets

The main challenge for the SEM in participating in full day-ahead price coupling is that its design is fundamentally different from the approach used in other markets in North West Europe[30], with the latter having strongly influenced the design of the Framework Guidelines and market coupling initiatives. To a large extent, the differences in the SEM design reflect the particular challenges that a small, relatively isolated island system faces in maintaining a secure supply and mitigating market power.

These differences in high-level market design are summarised in Table 2. Whilst the electricity markets in North West Europe differ in detail, they have similar characteristics for these high-level features. The differences in market design mean that under the proposed timetable for the development of market coupling, the SEM is expected to join the day-ahead price coupling arrangements relatively late (in around 2014).

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30 For the purposes of this report, North West Europe is defined as covering the Nordic markets, BETTA (GB) and the CWE market (France, Germany, the Netherlands, Belgium and Luxembourg). These are the markets that SEM would be coupled to in a regional price coupling solution.

Table 2 – Summary comparison of market design features

Design feature	SEM	NW European markets
Number of physical markets	Mandatory physical pool based around single ex-post price, with no day-ahead market (other than to fix interconnector flows)	Multiple forward and spot markets with voluntary participation, typically including a single day-ahead auction for hourly lots; mandatory settlement ex-post for imbalances
Form of generation bids	Complex commercial and technical bids, with generators required to bid their short-run marginal cost	Non-complex bids which can be simple bids (covering one hour) or block bids (covering several hours)
Market scheduling and dispatch	Central scheduling of all generation by optimisation algorithm; (ex-post) central dispatch by TSO; out-of-merit dispatch compensated at bid price (short run marginal cost) , no material imbalance exposure	Self-scheduling based on contracted positions; redispatch (by consent) by TSO through voluntary balancing mechanism; balancing actions paid at bid price, with firm advance commitments and out-turn imbalance calculations
Timing of gate closure	Currently day-ahead at 10am for data submissions, but scheduling uses out-turn availability, demand and wind generation data. Modification pending to change timing of day-ahead gate closures and introduce within-day gate closure (10 hours ahead of trading window)	Intra-day gate closure is typically within a few hours of real time
Composition of wholesale prices	Separate prices for energy and capacity, no material imbalance exposure	Prices reflect a single product with no explicit separation of energy and capacity payments; separate pricing for imbalance exposure

We now make a number of observations about the interaction between the main features of the SEM (as described above), and the requirements for the day-ahead market coupling (as discussed in the previous chapter).

3.2.1 Price coupling

Under price coupling, all available interconnection capacity is made available to the market coupler and no individual market participant has preferential access to the capacity (at the day-ahead stage). Therefore, the introduction of a day-ahead market would have consequences for the use of interconnection capacity holdings in the SEM.

The Framework Guidelines require the available transfer capacity to be defined in relation to the physical availability of the interconnector equipment (i.e. ignoring any local transmission constraints). This is currently the case under the SEM rules and should be retained.

The introduction of price coupling arrangements may raise issues about the treatment of the two interconnectors (post 2012) between SEM and BETTA. Our understanding is that the Moyle and East West Interconnectors would not be differentiated under price coupling arrangements as the central coupling algorithm only considers the total available transfer capacity between the day-ahead markets. However, the SEM Committee has recently consulted on its position that it is not minded to treat them as a single interconnector[31], a position supported by the interconnector owners.

3.2.1.1 Interconnector capacity holdings

Holders of 'physical' interconnector rights in the SEM have the right to bid interconnector capacity into the (ex-ante) market schedule. If (and only if) the bid is accepted in the ex-ante schedule, then the interconnector user is deemed to nominate an **intended** flow against its capacity holding.

Under the draft Framework Guidelines, there must be 'use-it-or-sell-it' (UIOSI) arrangements under which all available (unused) interconnection capacity rights are made available to the day-ahead market coupler. Capacity holders who do not use their capacity receive revenue based on the day-ahead price differential between the two interconnected markets (assuming there is a flow in the same direction as their capacity holding).

The UIOSI arrangement could use the earlier ex-ante gate closure (EA1) set out in the intra-day SEM modification currently being progressed[32]. This modification will ntroduce a 'use it or lose it' (UIOLI) provision to comply with the current congestion management guidelines.

3.2.2 Common gate closure times

The SEM Committee's March 2010 decision document on market integration proposed to bring the day-ahead gate closure in the SEM in line with the timing in European markets[33]. However, the impact on gate closure of day-ahead market coupling has not been fully resolved. The trading day also differs, with a trading day in most European day-ahead markets commencing at midnight CET (11pm Irish time), and the Irish schedule day starting at 6am.

If the long term capacity holdings become entirely financial in nature, then we believe there would be no need to create an ex-ante schedule before operation of the day-ahead market

However, if long term physical capacity rights were to be retained, there would need to be an ex-ante run of the SEM schedule to determine the use of physical capacity rights **ahead of** the gate closure for the day-ahead market coupling.

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31 'Treatment of the East West and Moyle Interconnectors in the SEM. A Consultation Paper. SEM-11-001', January 2011, SEM Committee.

32 Mod_18_10. Intra-Day Trading in the SEM. This would introduce two ex-ante gate closures, with the ex-ante MSP run after the first gate closure being used to determine the use of physical interconnection capacity rights.

33 'SEM Regional Integration. Consultation Paper Responses and SEM Committee Decision. SEM-10-011', 3 March 2010, SEM Committee.

An indicative timeline is set out below, using the first of two ex-ante gate closures as set out in the proposed intraday modification[34]:

- **8am (D-1):** parties bid into SEM at the first ex-ante gate closure (EA1) with interconnector bids restricted to holders of physical capacity rights only.
- **9.30am (D-1):** SEMO confirms which interconnector bids are in merit (based on forecast demand). The TSOs release all remaining available interconnection capacity to the day-ahead market coupling (under the Framework Guidelines, all available interconnection capacity must be released into day-ahead market coupling rather than being held back for SEM parties). No other market information is released.
- **11am (D-1):** parties bid into the local day-ahead market and into the SEM at second ex-ante (or day-ahead) gate closure (EA2).
- **1pm (D-1):** results of market coupling are published and SEMO releases ex-ante market schedule.
- **8am (D):** intraday gate closure (WD1) for trading window from 6pm as set out in the proposed intraday modification.
- **9.30am (D)**: within-day schedule published by SEMO.

The timings (and the definition of a 'day') would need to be adjusted from the timing set out in the proposed intraday modification to fit more closely to the proposed timings in the day-ahead market coupling process in North West Europe.

For example, as noted in Section 2.3.2, current practice in Nordpool and in the CWE markets is for the TSOs to release the available interconnection capacity to the day-ahead coupling 90 minutes ahead of the day-ahead gate closure.

Therefore, (as shown in the example above) the first ex-ante gate closure and schedule would need to be brought forward by 90 minutes from the timing of 9.30am set out in the proposed intraday modification. This means that it would coincide with the timings for the within day gate closure for the previous trading day.

The second ex-ante gate closure would be brought forward by 30 minutes to be in line with the day-ahead gate closure in the other coupled markets.

3.2.3 Common bid format

The data passed to the market coupler will not include the full complexity of SEM technical and commercial offer data. As a result, the ex-post schedule will not fully reflect the outcomes of the day-ahead market coupling.

Generally, any such schedule differences will manifest themselves either as costs or as risks. Even if we assume that the actual dispatch instructions by the TSO are equally efficient irrespective of the detailed design options for day-ahead trading, these scheduling differences may give rise to one-way compensation payments to participants.

If participants voluntarily submit simpler bids to the day-ahead market then it seems reasonable that they themselves should face the resulting risks. However, if their complex

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[34] Mod_18_10. Intra-Day Trading in the SEM. This would introduce two ex-ante gate closures, with the ex-ante MSP run after the first gate closure being used to determine the use of physical interconnection capacity rights.

bids are converted to a simple bid format by a central agent, then the risks should perhaps be socialised.

The rules on what bids will be accepted from the local day-ahead markets will need to be agreed centrally. Currently, the Price Coupling of the Regions (PCR) process (being led by the power exchanges) is currently defining the block bids that can be put into the central algorithm, with the aim of finalising the list in early 2011. A range of types of block bid are under consideration, some of which may have a similar effect to complex bids. The power exchanges will need to manage the risk that the acceptance by the central market coupler of increasingly complicated block bids increases the risk of non-unique solutions being produced by the market coupling process.

Ultimately a 'block bid' is a type of complex bid. The SEM complex bids are intended to reflect the cost structure of different types of generator, and especially the start-related costs which in a small island system have an important influence on overall dispatch cost. The market coupling is likely to deliver more efficient outcomes (from an Irish perspective) if the type of permitted block bid reflects the characteristics bid into the SEM. We recommend that in the creation of bids for use in the market coupling, the local market operator should make the maximum use of the flexibility conferred by block bids.

The risk of late engagement of the SEM in the definition of the price coupling process is that the RAs and other SEM parties would be left with even less (or at worst no) influence than at present over the design of day-ahead market coupling arrangements, such as bids accepted by the central market coupler. The nature of the bids in the SEM is one of the critical differences between it and other markets (and a potential cause of risk and inefficiency in any coupling arrangements). In our view, this issue merits early discussion under the banner of the definition of 'block bids'.

3.2.4 Comparable prices

In order to produce an efficient market coupling result, then the prices must be for a comparable product (as noted in Section 2.3.4). Therefore all bids into the market coupler from the Irish day-ahead market should cover both capacity and energy (inclusive of start and no load costs as far as is possible).

If capacity payments are not correctly taken account of in the market coupling process, then the SEM bids and the resulting day-ahead price will seem artificially low from the perspective of the market coupling. The SEM will be subsidising the export of both energy and capacity to adjacent markets.

The SEM faces a price cap of €1000/MWh, a price floor of €-100/MWh, and a requirement for generator bid prices to be in line with short-run marginal cost. The application of these price restrictions to the market coupling has not been reviewed in depth, given for example the absence of any such restrictions in the adjacent BETTA market.

Note that the discussion of prices within the document relates to scheduled energy volumes, but not to actual dispatch or metered quantities. We make the assumption throughout the document that the first-order impact of the day-ahead market under each of the options under consideration would be to leave the process of central dispatch unchanged. If day-ahead quantities are treated as price-taker volumes then there may be possibly some distortions, depending on the rules used in dispatch.

There would also be a requirement to convert all day-ahead bids into a single currency. As a point of detail, the existing generation bids into the SEM are in the local currency, £ sterling for generators in Northern Ireland and € for those in the Republic of Ireland.

3.2.5 Participation of buyers and sellers

Under the SEM, only generators (and demand side units) are actively bid into the market. Suppliers (and autonomous generators) have limited financial commitment associated with any particular forecast volumes. Therefore the adoption of a day-ahead market with firm day-ahead commitments would represent an increase in the level of activity and financial commitment at the day-ahead stage. It would also allow parties more price certainty day-ahead than at present.

3.2.6 Liquid and reliable day-ahead market

Liquidity will be a crucial aspect of the success of the day-ahead market. Like any set of market arrangements, price coupling will work most effectively when it is based on a group of liquid markets. The determination of interconnector flows through the operation of liquid markets will help to deliver efficient scheduling and use of the interconnectors at the day-ahead stage.

It is worth noting that increasing the efficiency of interconnector flows may not deliver lower prices for Irish consumers but could deliver instead higher prices that would benefit Irish generation. The impact of having more efficient interconnection flows can be proxied by an analysis of the impact of having expanded interconnection.

In Pöyry's intermittency study for GB and Ireland[35], higher levels of interconnection capacity (in the core scenario compared to the interconnection sensitivity) led to higher prices in the SEM and lower curtailment of wind. This was because the expanded interconnection capacity enabled the system to export more at times of high wind in Ireland.

A high level of liquidity (and the efficient of use of the interconnectors generally) should mitigate concerns about market power by effectively opening the SEM to competition from the bigger GB market.

However, Ofgem has acknowledged that there appears to be low levels of liquidity in the wholesale electricity market in GB compared to other electricity markets in Europe and elsewhere[36]. Although much of the attention has been focused on the low levels of liquidity in longer-term products, there is also much lower participation in the day-ahead market in GB than in other European markets.

For example, Ofgem reported that in the first five months of 2010, less than 1% of consumption in GB was traded through the day-ahead market. Over the same period, the day-ahead auctions for Germany covered nearly 40% of consumption[37]. Similarly, 26% of electricity consumption in the Netherlands was included in the APX day-ahead sport market in 2009.

Therefore, it is important that the decision on the options for the Irish day-ahead market takes account of developments in day-ahead market liquidity in BETTA. For example, by

35 'Impact of intermittency. How wind variability could change the shape of the British and Irish electricity markets. Summary report', July 2009, Pöyry Energy Consulting.

36 'GB wholesale electricity market liquidity: summer 2010 assessment', Ofgem, July 2010.

37 'GB wholesale electricity market liquidity: summer 2010 assessment', Ofgem, July 2010.

December 2010, there were reported to be 60 members of the GB spot market operated by APX, and 21 members of the N2EX exchange[38].

It is also important to note that the low level of participation at the day-ahead stage has not stopped the development of day-ahead market coupling initiatives involving GB. For example, price coupling arrangements with the Netherlands have been developed in preparation for the commissioning of the BritNed interconnector between the two countries, which is expected later this year. This is expected to boost liquidity in the day-ahead market in GB.

The introduction of **effective** market coupling to the SEM is expected to have a major beneficial impact on the overall SEM outcomes (by 2012, import capacity will approach 25% of average SEM demand). Benefits could include better balancing of the variable wind production, and mitigation of remaining market power. Without sufficient liquidity these benefits will be reduced.

3.2.7 Firm day-ahead trades

3.2.7.1 Mechanics of settlement

Aside from the commercial intent of 'firm' trades as discussed in section 2.3.7 above, the mechanics of payment are an important aspect of design. There are two broad options but we believe that these are commercially equivalent:

- the ex-post market is settled as a gross pool (as at present) and the day-ahead market is settled as a CFD; or
- the day-ahead market is settled as a firm forward trade with the ex-post market being settled as a residual.

Under the CFD approach, SEM participants with volumes matched in the day-ahead auction would receive or make a CFD payment based on the difference between the day-ahead price and the ex-post SEM price (based on their day-ahead volume):

$$\text{CFD payment} = Q_{DA}*(P_{DA} - SMP)$$

In payment terms, the algebraic equivalence between the CFD approach and a residual ex-post market option (in which there is settlement of the day-ahead market with the residual volumes being settled at an imbalance price) is set out below:

$$\begin{aligned}
\text{Total Revenue} &= \text{SEM revenue}^{39} + \text{CFD payment} \\
&= MSQ*SMP + Q_{DA}*(P_{DA} - SMP) \\
&= Q_{DA}*P_{DA} + SMP*(MSQ - Q_{DA}) \\
&= \text{Day-ahead revenue} + \text{imbalance payment}
\end{aligned}$$

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38 'Open letter: Liquidity in the GB power market update and next steps', Ofgem, December 2010.

39 In the interests of simplicity, we have focused simply on the SEM revenue based on the ex-post schedule, and have not included constraint payments and capacity payments.

3.2.7.2 Price and volume risk

The CFD would provide a firm day-ahead price to SEM participants by offering protection to generation and demand against variations between the day-ahead price and the ex-post price, provided that the day-ahead volumes equal those calculated in the ex-post SEM schedule. However, the revenue received under the CFD will only equal the day-ahead revenue if there is no change in quantity between the day-ahead and ex-post schedules (i.e. $MSQ = Q_{DA}$)[40].

Essentially, the CFD payment described above (or the alternative residual market) combines a **price hedge** for day-ahead volumes which are matched in the ex-post schedule with a quasi-**imbalance risk** (priced at SMP) for volumes which are not matched.

It is worth noting that the CFD approach has not been successful in encouraging forward trading in the SEM at present, with the recent report for the RAs on market power and liquidity in the SEM[41] describing the 'relatively illiquid non-directed contract market' and that there 'appears to be a residual and reasonable concern about the lack of liquidity in the contract market'.

3.2.7.3 Implications for demand and variable generation

The ex-post market schedule in the SEM takes account of actual demand, generation availability and output from variable generation (primarily wind), as opposed to using the forecast levels available at the day-ahead stage. At present, there are (essentially) no firm commitments day-ahead and participants face minimal 'imbalance' risk despite the long gate closure timescales for submission of commercial and technical offers.

In establishing firm day-ahead contracts between buyers and sellers, a 'volume' or 'imbalance' risk' would therefore be faced by market participants[42]. For demand and price-taking generation there would be an exposure to forecast error, based on the difference between day-ahead contracted quantities and out-turn volumes.

The consequences of forecast error will vary according to whether the day-ahead price is lower or higher than the out-turn level. For example, if a day-ahead demand forecast is lower than the out-turn level, then the buyer will be fully exposed to the ex-post SMP for the shortfall. If the day-ahead demand forecast was too high, then the buyer will effectively have bought quantities in the day-ahead market in excess of its final requirements. Even it can sell back this excess volume (e.g. at the SMP), this is likely to incur additional net purchase costs for the supplier. These costs may be greater if the ex-post price is more volatile (if for example, day-ahead volumes were treated as price-taking generation in the ex-post schedule).

At present, SEM participants pay the ex-post energy price for 100% of their scheduled energy volumes, so it is debatable whether the introduction of this 'imbalance' risk is an increase or a reduction from the existing exposure to ex-post prices. The significance of

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40 Assuming a non-zero SMP.

41 'Market Power and Liquidity in the SEM. A report for the CER and for the Utility Regulator', Cambridge Economic Policy Associates, 15 December 2010.

42 This risk is offset by the ability for participants to lock in prices and quantities at an earlier stage. We expect that day-ahead prices would generally be less volatile than ex-post prices, and some participants would be expected to benefit from earlier price certainty.

the new imbalance risk depends on whether ex-post prices become more or less volatile as a result of the day-ahead market introduction.

3.2.7.4 Implications for price-making generation

In most European electricity markets, generators are responsible for self-scheduling their generation, and suppliers are responsible for forecasting their demand and choosing their own level of forward trading. It is therefore considered appropriate for participants to face imbalance price exposure for deviations from their contractually committed volumes as they have some control over their own schedules.

Under the prevailing design in European markets, the day-ahead volume may not be delivered for several reasons, principally:

- generation availability falls, in which case the generator becomes liable for imbalance charges if it has not traded out its position by the final gate closure; or
- generator participates in the balancing mechanism on the basis of bids and offers at prices which it chooses, that will leave it no worse off than at the day-ahead stage.

In either case, there is no need for additional measures to protect the day-ahead volume because the generator is clearly responsible for differences from the day-ahead volume.

The situation is more complicated in the SEM because of the mandatory and centralised nature of the ex-post pool combined with requirements to submit commercial offers in line with short-run marginal cost, 'accurate' technical offer data and a tight limitation on 'price taker' participation[43]. This means that price making generators have very limited influence over their own schedule and therefore their exposure to imbalance risks due to factors outside their responsibility is significant. The challenge is therefore to identify who is responsible for the change in volumes and ensure that each party is appropriately protected.

In an extreme example, a generator might have committed to a day-ahead trade at a given price whereas the ex-post schedule might deliver a lower schedule quantity but a higher SMP[44]. The financial exposure of the generator could be high, unless some compensation payment is made (e.g. in cases where the volume difference was due to factors outside its responsibility).

If the principles of 'firm' trades are followed, then price makers would also be exposed to imbalance payments to the extent that their availability falls after the day-ahead market coupling and they are unable to be scheduled at the day-ahead levels.

In order to meet the principles of 'firm' trades, we believe that some mitigating compensation should be made against certain 'imbalance' risks to ensure that generators are not exposed to risks outside their own responsibility (e.g. a changing system demand forecast). Under the same principles, compensation would not be made to generators when the schedule difference arises from a technical failure on the generation equipment.

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43 The England and Wales Pool featured central scheduling, but generators had commercial freedom in their technical and commercial data, and those with forward contracts typically submitted zero-priced bids and sculpted their availability to ensure that their schedule met their contractual commitments.

44 This is a plausible although unexpected outcome, due to the complex nature of the optimisation

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4. DESIGN OPTIONS

Pöyry has been appointed by the Regulatory Authorities to provide advice on the options for the development of a day-ahead trading solution for the SEM. The SEM Committee has set requirements that the day-ahead trading solution should:

- allow day-ahead coupling of the SEM and neighbouring markets that is compatible with the common price coupling solution being developed at a European level; and
- not fundamentally alter the SEM rules[45].

We designed options for a day-ahead market around the requirement not to fundamentally alter the SEM rules, with reference to the High Level Principles of the SEM market design[46]. The market design is based around the operation of an ex-post gross mandatory pool with central commitment[47]. A working assumption across all of the options is that the true dispatch remains unchanged, based on the underlying costs of generation.

There are also a number of more detailed features of the ex-post market set out in the High Level Design, each of which are followed (with respect to the ex-post market) within our proposed options:

- single system marginal price (SMP) for each half hour based on an ex-post optimised schedule for the whole day;
- gate closure suitably long in advance of real time;
- complex bids from generators;
- indicative and real time dispatch schedule based on most accurate demand forecast, wind generation forecast, reserve requirements, transmission constraints and generation availability;
- single price for the island;
- payments for transmission constraints;
- de minimis level for compulsory participation of generation;
- provisions for renewable generators to be treated as price-taking volumes in the ex-post schedules; and
- explicit capacity mechanism.

In this chapter, we first provide an overview of the key differences between the options at three different decision points. We then look in detail at the issues around each of these decision points, before concluding with a summary of each option.

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45 Given the requirement not to fundamentally alter the SEM rules, we have not developed or assessed more radical options which would require a fundamental redesign of the SEM, such as a move towards the BETTA market design; which has bilateral trading arrangements in a series of rolling markets, self-dispatch and simple bids.

46 ‘The Single Electricity Market (SEM). High Level Design Decision Paper. AIP/SEM/42/05.’ 10 June 2005, CER and NIAER.

47 In this context, we have interpreted ‘centralised commitment’ as referring to centralised optimisation of the ex-post schedule.

4.1 Definition of options

We have developed six conceptual options for the introduction of day-ahead price coupling between the SEM and other European markets. These are each based around the creation of a reliable and liquid day-ahead market, which enables generators to lock in firm prices and quantities at the day-ahead stage. Therefore, all of the options are considered to be consistent with the current market coupling initiatives in other European countries (subject to detailed legal interpretation).

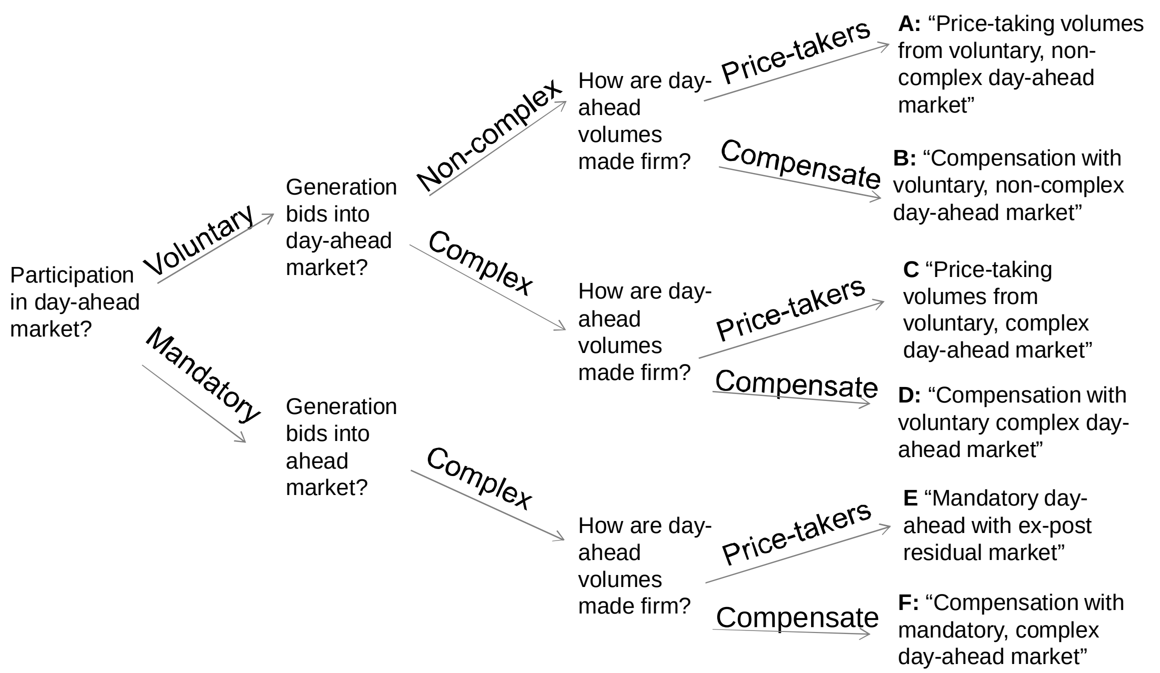
The options can be differentiated by the answers at three decision points:

- **Should participation in the day-ahead market be mandatory or voluntary?**
- **What is the form of generation bids into the local day-ahead market?** – either market participants take responsibility for creating non-complex bids for use in the day-ahead market, or their complex bids are converted to non-complex bids by a centralised agent.
- **How are day-ahead volumes made firm?** – either by being treated as price-taking volumes in the ex-post schedule or through compensation payments (where appropriate) for differences between day-ahead and ex-post volumes.

We have assumed that as now, for those aspects of the market which are mandatory, complex bids will be submitted by participants. Therefore, we do not present an end-to-end option which combines a mandatory day-ahead market with the acceptance of non-complex bids.

This means that we present the six options described in Figure 3.

Figure 3 – Overview of options for day-ahead trading solution in the SEM



In option E, the day-ahead prices are made firm through settlement of the day-ahead market with imbalance payments for residual differences in volumes in the ex-post market.

In the other five options, the Irish day-ahead market is a CFD market with settlement in the ex-post market. In practice, the choice between these two approaches does not directly affect the commercial position of market participants.

These options are intended to highlight the key choices in setting the design of the day-ahead market arrangements, but are by no means exhaustive. Detailed design issues have not been addressed (although we have noted several in the discussion of the options).

In the next three sections, we discuss in turn the issues related to each decision point, according to the following structure:

- a summary of the high-level binary options available at each decision point;
- discussion of the issues in relation to definition, implementation and implications for these options; and
- a list of more detailed points not considered fully in this paper.

4.2 Is participation in day-ahead market voluntary or mandatory?

At this decision point, there is a simple choice between:

- allowing voluntary participation by generation and demand in the day-ahead market; or
- mandating participation in the day-ahead market (by – or on behalf of – all generation and demand).

We now discuss the following issues in relation to the definition, implementation and implications of these choices:

- responsibility for forecasting demand and output from variable generation;
- liquidity in the day-ahead market, which relates both to the level of participation and to the availability of interconnector capacity; and
- interaction between day-ahead market coupling results and the production of the ex-ante schedule for the SEM (which is still required for planning purposes).

We conclude this section by listing a number of detailed issues in relation to this decision point that have not been considered in detail in this paper.

4.2.1 Responsibility for forecasting demand and variable generation

In a voluntary day-ahead market, we assume that suppliers and variable[48] generators will be responsible for determining their day-ahead contract volumes. They will be responsible for making their own forecasts, and will be financially responsible for the accuracy of those forecasts. They would choose the volume to trade forward informed by a number of factors, including:

- the expected levels of day-ahead versus ex-post prices;
- the predictability of their demand or generation; and
- the flexibility of their demand or generation.

48 In general, variable generation is assumed to have limited (if any) flexibility. The term here includes those registered as 'autonomous'.

Suppliers could employ a risk mitigation strategy of only bidding a subset of their demand into the day-ahead market, which would leave them exposed to the SMP on only the remaining portion of demand.

If participation in the day-ahead market is mandatory for all generation, then the whole of Irish demand as well as all price-taking generation[49] must be included in the market to ensure the most efficient market clearing solution. We have assumed that with a mandatory market, the TSO would provide an aggregate day-ahead forecast for demand and variable generation. This is consistent with the treatment of these parties under the current SEM arrangements.

It also means that variable generation and suppliers are not held responsible for forecast errors at the day-ahead stage when they have not voluntarily exposed themselves to this risk. Under these circumstances, the net cost of forecast errors will be socialised across market participants and potentially ultimately customers (depending on the cost recovery mechanisms).

The drawback of socialising the costs of forecast errors is that it will reduce incentives on participants to improve forecasting (or to gather better information on their customers' intentions). The RAs would have the option of providing TSOs with incentives to improve their demand and wind forecasting.

Within the class of 'mandatory' day-ahead markets, a more radical option would be to make suppliers and variable generators individually responsible for their day-ahead forecasts. This would provide a source of competitive advantage for those participants able to most accurately forecast out-turn values at the day-ahead stage. However, it exposes parties without day-ahead volume certainty to increased risk compared to other participants.

4.2.2 Liquidity in the day-ahead market

In considering the choice between a voluntary and mandatory market, the ability of a voluntary market to deliver liquidity is an important consideration. In a day-ahead market coupling, the effective level of liquidity behind the Irish day-ahead quantities and prices will be determined by three factors:

- level of participation in the SEM day-ahead market;
- level of participation in the day-ahead market in BETTA (and in other markets in the market coupling arrangements); and
- availability of interconnection capacity for day-ahead market coupling, as this determines the ability of the Irish market to benefit from liquidity in other markets.

In considering whether to make the day-ahead market voluntary or mandatory, the RAs will need to take a view of the likely contribution of all three factors to the delivery of a liquid Irish day-ahead market. For example, one of the suggested benefits of market coupling is that it will provide the Irish market with access to a much larger market. However, if interconnection capacity available to the day-ahead market is limited and/or there is little participation in the day-ahead market in BETTA, then it will be more important to ensure a high level of participation in the Irish market.

49 Alternatively, all SEM demand net of price taking generation. This sub-variant is not taken further in this paper.

4.2.2.1 Level of participation in the day-ahead market

By definition, mandatory participation in the day-ahead market should deliver a highly liquid market as all generation and demand (based on day-ahead forecasts) will participate in the day-ahead auction. This feature of mandatory markets has been recognised by the SEM Committee in discussions about the performance of the current ex-post pool[50] and the use of the ex-ante schedule to determine interconnector volumes as an option for loose volume coupling[51].

The implications of the exposure to forecast errors and imbalance risk for demand and generation will influence the incentives for the parties to participate in a voluntary day-ahead market.

4.2.2.2 Level of participation in the day-ahead market in BETTA

BETTA participants will be concerned that the mechanics of day-ahead market coupling match their own market and those of France and the Netherlands, as well as Ireland. To the extent that there is any impact on the GB day-ahead market from change to the arrangements to favour the SEM market design, this may be a disincentive to participate in the GB day-ahead market. We note that several of the SEM players also have a position in the GB market and there will be concerns that if the market coupling design favours GB players then purely SEM participants may be at a disadvantage. This merits further consideration in the implementation phase for any option.

4.2.2.3 Availability of interconnection capacity for the day-ahead market

We recommend that the interconnector capacity available to the day-ahead auction should be the complete physical capacity of the interconnectors (subject to connection agreements) with no reduction for local transmission constraints.

Holders of ‘physical’ interconnector rights in the SEM have the right to bid interconnector capacity into the (ex-ante) market schedule. If (and only if) the bid is accepted in the ex-ante schedule, then the interconnector user is deemed to nominate an **intended** flow against its capacity holding.

The SEM has no provision for unilateral declaration of flow on an interconnector. Therefore, to allow the nomination of physical rights outside the market coupling process, any physical nominations must be determined in a run of the ex-ante SEM market schedule which **precedes** the day-ahead gate closure (as under the intra-day SEM modification currently being progressed[52]).

The flows determined by the ex-ante schedule under the existing process are based on a full representation of the Irish markets through mandatory participation and complex bids, and take into account interconnector losses. However, this run of the ex-ante schedule only represents the market in GB to the extent that parties hold long-term interconnector

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50 ‘Market Power and Liquidity. State of the Nation Review. An Information Paper’, SEM-10-051, SEM Committee, August 2010.

51 ‘SEM Regional Integration. Consultation Paper Responses and SEM Committee Decision’, 7 March 2010, SEM Committee.

52 Mod_18_10. Intra-Day Trading in the SEM. This would introduce two ex-ante gate closures, with the ex-ante MSP run after the first gate closure being used to determine the use of physical interconnection capacity rights.

capacity rights and bid the expected GB price[53] into the SEM at the day-ahead gate closure.

Under the day-ahead market coupling, the interconnector flows determined by the central coupling algorithm will be influenced by all bids received in the entire day-ahead market in GB. However, the central coupling algorithm has a less complete representation of the Irish market than the ex-ante schedule because it uses non-complex bids (and possibly voluntary participation).

Therefore, the decision on the balance between physical and financial long-term capacity rights needs to take into account the relative strengths and weaknesses of these two approaches to determining interconnector flows.

At this point, it is worth noting that the RAs have themselves raised concerns about the effective use and scheduling of interconnector at day-ahead stage under the current SEM arrangements. At present, the direction of flows across Moyle are reported to be in the same direction as would be expected from the difference in BETTA and SEM prices in only 50% of hours[54].

The RAs would also need to consider the need for compliance with the Framework Guidelines, particularly whether this would be satisfied by the allocation of all interconnection flows through an ex-ante schedule, which left only the residual capacities (and reverse flows)) for the day-ahead market.

4.2.3 Interaction between creation of the day-ahead and ex-ante schedule

Participation in the day-ahead market (or auctions) is voluntary in BETTA, the CWE markets and the Nordic markets. If the same approach is taken in the SEM, then SEMO will need to continue to separately collect bids from the entire market to allow the production of an ex-ante schedule for dispatch purposes.

If participation in the local market is mandatory, then the result of the market coupling exercise (or at least the same data) may be used to provide the ex-ante schedule.

4.2.4 More detailed issues not considered in this paper

There are a number of more detailed issues that are not considered further in this paper:

- Are there any exclusions from participation in the day-ahead market (e.g. purely financial players without a physical position in the SEM)?
- Under a voluntary approach, could a central agency, such as the local day-ahead market operator, offer a commercial service to act on behalf of some of the market demand or generation?
- What are the detailed mechanics of creating an ex-ante SEM schedule around the day-ahead market arrangements?
- Under a mandatory approach, the costs of day-ahead forecast errors (e.g. for wind or demand) by a central body should be socialised across which groups? (e.g. all consumers, all participants, all wind plants, etc.).

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53 Allowing for capacity payments and other variable (non-energy) costs.

55 This would require the aggregation of any simple bids into an aggregated bid-offer curve. This is the role of the local market operator and the resulting aggregated data is then passed to the market coupler.

We also note that there are a number of potential developments in the GB market which variously remove or introduce potential distortions to trade with SEM. These include:

- the removal of transmission use of system (TNUoS) charges from interconnectors;
- the broader 'Project TransmiT' review of transmission charging;
- the Treasury proposals for the application of a carbon price support (effectively a tax on fuel used in power generation, which might apply to Northern Ireland as well as GB); and
- a series of other measures as part of the Electricity Market Reform proposal which might alter the generation mix and the bidding incentives of low carbon generation.

These issues have not been considered in the drafting of this paper.

4.3 What is the form of generation bids into the local day-ahead market?

The form of bids accepted by the market coupler is unlikely to include the full complexity used in the SEM commercial and technical offer data. On that basis, we have selected two choices for the submission of bid data by participants to the local day-ahead market operator:

- submission of full SEM-type complex bids by participants, which would require a central agency to convert these to the simpler form used by the central market coupling algorithm; or
- submission of simple or block bids by participants for use directly in the day-ahead market[55].

Where complex bids are submitted to the day-ahead market, then we assume these bids should be the same as those submitted to the ex-post SEM at the day-ahead stage and (for licensed generators) should accord with the Bidding Code of Practice. The results of the day-ahead auction should not in themselves change the content of the complex bids into SEM.

We now discuss the following issues in relation to the definition, implementation and implications of these choices:

- the role of the local day-ahead market operator in delivering bids to the central market coupler based on the bids provided by market participants; and
- the calculation of comparable bid and offer prices for use in market coupling arrangements.

We conclude this section by listing a number of detailed issues in relation to this decision point that have not been considered in this paper.

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55 This would require the aggregation of any simple bids into an aggregated bid-offer curve. This is the role of the local market operator and the resulting aggregated data is then passed to the market coupler.

4.3.1 Role of local market operator in delivering bids to the central market coupler

The operator of the SEM day-ahead market would gather bids and offers from local generation and be responsible for providing bids and offers in an acceptable form to the market coupling algorithm. We have assumed that the market coupling algorithm will accept the following type of bids and offer from the local market operator:

- an aggregated bids and offer curve for all simple bids; and
- (anonymised) block bids (format yet to be defined) that can be directly passed on from market participants.

4.3.1.1 Passing on of bids to the central market coupler

If the local day-ahead market operator in Ireland accepts only those types of bid that are accepted by the central market coupler, then this would facilitate the entry of power exchanges into the SEM because it would be comparable to most other European markets.

However, it would have the following implications for the operation of the SEM:

- generation participating in the day-ahead market will be exposed to the risk of submitting non-complex bids in which they have to spread start-up and no-load costs over an unknown number of hours[56];
- the impact of the bidding principles could be weakened as they would be more difficult (and potentially even impossible) to apply (in their current form) to the bids submitted in the day-ahead market; and
- different bids would have to be submitted into the local day-ahead market and the SEM (even if day-ahead gate closure was at the same time) because the SEM is assumed to only accept complex bids.

4.3.1.2 Conversion by a central agency of complex bids to non-complex bids

The alternative choice at this decision point is that a central agency (possibly the local day-ahead market operator) accepts more complex bids than is accepted by the central market coupler. This raises the question of whether a generator should be compensated for differences between the day-ahead and ex-post scheduled quantities where they arise from the simplification of its bids by a central agency – for example, start costs may be included in bid prices assuming a different operating profile to that which is actually accepted.

The central agency would have to convert the complex bids into an aggregated bid/offer curve and/or into some form of block bids. In both cases, the central agency would need to produce a set of multiple bids and offers from the Irish market.

An obvious tool to create block bids and offers from complex bids is the existing MSP software. Therefore, the conversion of complex generation bids into the form required by the central market coupler may be a more suitable role for SEMO (who already has systems in place for dealing with complex bids) than a commercial power exchange. In

56 Complex bids have been used under the SEM arrangements because generators faced with the combination of central scheduling and central dispatch with a long gap between the submission of bids and real time have no means to manage the start-up/no-load risks other than to include these as separate bid components.

particular, there may be administrative efficiencies in doing this given that the bids will also be used in the SEM scheduling.

Based on the results of an ex-ante schedule, the MSQ for each participating price maker generation unit could be used to calculate an implied cost to produce that schedule. The software also calculates shadow prices and uplift prices for each period.

Block bids derived from an ex-ante run of the schedule are all premised on the forecast level of demand taken into account in the ex-ante schedule. The challenge is that any block bids calculated in this way would assume a single profile of production which would not accurately reflect the costs of alternatives (e.g. alternative import/export patterns leading to alternative patterns of unit commitment).

In any period, the range of effective demand must fall within the full range of imports and exports (allowing for interconnector ramp rates). If the market is voluntary then only a subset of generation and demand will be included and the impact of the level of import or export will be significant.

The detailed resolution to this challenge clearly cannot be defined until the accepted form of block bids is agreed (including whether and how many alternative bids are acceptable). We have sketched out some ideas below (some complementary, some competing) on how a special run of the ex-ante schedule could be used to turn complex generation bids into profiled block bids for submission to the market coupler.

There are a number of choices for the input data to the ex-ante schedule (effective demand, to include a proxy for the level of GB import/export):

- It may be possible to run two or more ex-ante schedules, e.g. one case using the forecast level of demand plus an allowance for the maximum export capacity of the interconnectors, and a second assuming full import to SEM.
- It may be possible to create a schedule which contains a best guess of the actual patterns of import/export (and perhaps a range of alternative outcomes around that). SEMO could obtain a set of current BETTA prices from the continuously traded market, which would be entered to the market schedule as in the current arrangements (note that there would need to be adjustments for variable costs associated with interconnection, e.g. GB losses, BSUoS, link losses, as well as the expected value of the capacity payment in each period) – in this way the schedule would be an approximate estimate of the outcome of the full market coupling process.
- If the day-ahead market is mandatory then the ‘net demand’ figure needs to include a forecast of all demand less price taker generation as in the existing ex-ante schedule (plus import/export); however if the market is voluntary then willing participants will submit their own demand forecasts**.**

There are a number of choices for the volume profile and prices used for a block bid for individual generators:

- For those generators whose schedule is identical in a “high import” and “low import” run, then the block bid for the actual production should be based on this single production profile in the hours of operation, with some increments for unused capacity.
- For generators scheduled to operate in every period in a run using a high level of imports, a block bid could be based on their scheduled level of operation with additional incremental bids derived from their incremental bid costs plus the calculated values of Uplift.

- For generators not committed in a period, a simple assumption could be made of a minimum operating level and the minimum number of committed periods, and a block bid constructed around those minimum patterns assuming the incremental prices plus an allocation of the start-up and no-load costs.

The timing for submission of bids into the Irish day-ahead market would have to be early enough for the central agency to convert the bids into an acceptable form for the central market coupler in line with the market coupling timetable. Therefore, if this requires a run (or runs) of the market scheduling software, then the gate closure for the SEM day-ahead market may need to be about 90 minutes[57] before the local day-ahead market operator has to pass on bids and offers to the central market coupler.

This would be earlier than the timing of bid submissions in other day-ahead markets, which could cause inconsistencies and possibly perverse flows – for example, if there are movements in gas prices between the submission of day-ahead bids in the SEM and in BETTA.

4.3.2 Comparable bid and offer prices

As discussed in Section 3.2.3, the bid and offer prices submitted in other European markets take the form of a single price that covers both energy and capacity. In the SEM, there is separation between an explicit capacity payment and the energy price (SMP). The SMP covers variable production costs, including start-up and no-load, and can in turn be separated into the shadow price and an uplift element.

We assume that the central market coupling algorithm will require bids based around a single energy and capacity price, as that remains the prevailing design in most other European markets. In order to produce an efficient market coupling result, then the bid and offer prices must be for a comparable product. Otherwise, if for example, SEM bids only cover energy, the resulting day-ahead price in the SEM will be artificially low, and the SEM will be subsidising the export of both energy and capacity to adjacent markets.

Where bids **into** the local day-ahead market are complex, then we have assumed a central agency would be responsible for calculating the single energy and capacity bid price to be sent to the central market coupler. This is because complex bidding is focused on the provision of information by the generator about its short-run marginal costs.

This has the advantage that as the same allowance for non-energy costs will be made to all bids, this should not affect the ranking of generators in the Irish day-ahead market.

The importance of this advantage means that our initial view is that a central agency in the SEM should also be responsible for adding an allowance for non-energy costs even in a voluntary day-ahead market where generators were submitting non-complex bids.

The detailed mechanics of how the central agency would forecast the non-energy costs have not been explored, but some form of forecasting rules for the local central agency are likely to be required. Compensation arrangements may also need to be developed to keep market participants whole for any change in volumes caused by a difference between the forecast and out-turn allowance for non-energy costs

57 In the proposed intraday modification, the ex-ante schedule is timetabled to be available 90 minutes after the ex-ante gate closure (for both gate closures).

4.3.3 More detailed issues not considered in this paper

There are a number of more detailed points in relation to the form of generation bids into the day-ahead market, which have not been considered in this paper:

- Is there a hybrid option under which participants could choose between submitting their own simple bids or asking the local day-ahead market operator to calculate simple bids on their behalf, based on the complex SEM bids?
- Who would be the local day-ahead market operator – SEMO is an obvious candidate, for accepting complex bids but could there be multiple operators (similar to the situation in some countries in which there are multiple power exchanges), which would allow participants to choose between submitting simple or complex bids?
- If complex bids are required from generators, does that reduce or remove the scope for participation by non-physical players in the day-ahead market (e.g. non-physical players)?
- If complex bids are required from generators (and processed by a central agency), how would the potential swing in interconnector volumes be dealt with in calculating the impact on bids?
- If complex bids are required from generators (and processed by a central agency), should any price data for GB (including BSUoS and other variable costs) be included in the process? (An alternative is to assume maximum import or maximum export as a starting point).
- If compensation is paid for differences between day-ahead and ex-post schedule quantities that arise from the creation by the local day-ahead market operator of non-complex bids from complex data; from whom should this compensation be recovered (e.g. all consumers, all day-ahead market participants, all generators pro rata to the importance of their start costs in total costs, etc.)?
- How should any physical interconnection capacity rights be taken into account in any special ex-ante MSP run to convert complex bids into profiled block bids? [58]
- What will be the impact on the efficiency and run-time of the central market coupling algorithm of submitting a profiled block bid from every generator participating in the Irish day-ahead market?
- How will the difference between SEM Schedule Day (starting 6am Irish time) and the calendar day used in other European markets be resolved?
- If much more frequent re-bidding is allowed within-day, then should participants be allowed to make simple bids within-day, internalising the risk of start-up and no-load costs, as they will already have a good understanding of their operating patterns?
- How do the generator bidding principles and the market price cap and floor apply in the day-ahead markets?
- Will interconnector ramp rates be used in the market coupling?

58 Inclusion of physical capacity rights will complicate the calculation of the total level of demand to be used in the run. This matters because the interconnector flows cannot be bid into the market coupling process and therefore could be distorted by the use of a higher level of demand (including maximum day-ahead capacity). One possible solution is to have an earlier run of the ex-ante MSP to determine use of interconnector bids, in line with the first ex-ante gate closure (EA1) proposed under the proposed intraday modification.

4.4 Impact of day-ahead volumes on ex-post schedule

The SEM differs from other markets because it is based around centralised ex-post scheduling. As discussed in Section 2.3.7, our view is that the provision of firm prices and quantities does **not** require that those prices and quantities must be respected within the ex-post market schedule. Rather, the day-ahead agreements must be (financially) firm on both buyers and sellers.

Although a firm day-ahead contract (which might be considered as a CFD around the SEM settlement) hedges against price movements, it does not address differences in volumes between the day-ahead market and the ex-post pool.

Therefore, the third decision point is **the treatment of the day-ahead volumes in the ex-post market schedule.** We present two broad choices:

- allowing the scheduled quantities to be set independent of the day-ahead volume with compensation payments made to parties for any loss resulting from any difference between the day-ahead market and the ex-post schedule for which the party is not responsible; or
- treat day-ahead volumes as price-taking generation in the ex-post schedule.

We now discuss the following issues in relation to the definition, implementation and implications of these choices:

- scope of protection for day-ahead prices and volumes;
- treatment of interconnector flows resulting from market coupling;
- the operation of a compensation payments mechanism; and
- the impact on the ex-post schedule and dispatch.

We conclude this section by listing a number of detailed issues in relation to this decision point that have not been considered in this paper.

4.4.1 Scope of protection for day-ahead prices and volumes

We have discussed in Section 2.3.7, our view that 'firm' should be defined as meaning that if one party fails to fulfil its contract **for reasons that fall within its responsibility**, then it should hold the other party whole and face any financial consequences.

Section 2.3.7 set out a number of examples in which it is not clear cut which party is responsible for changes between day-ahead and ex-post volumes. Therefore, a very important part of the detailed design stage will be to establish the circumstances under which generators should or should not be protected from changes between the day-ahead and ex-post markets.

This will be further complicated by the fact that in practice such differences will arise from a combination of causes. This will increase the pressure on the analysis of any such differences with the scope for challenge by market parties.

Under the class of options (A/C/E) in which day-ahead volumes are being fixed as price-taking generation, there will need to be a set of criteria for determining when these flows should be fixed and when they may be varied (e.g. if availability changes). This decision will need to be taken **before** the run of the ex-post scheduling software. Under the options in which compensation payments are made (options B/D/F), the compensation calculations could be made even later (potentially after ex-post pricing is set for the market), but the rules will still need to be clear to participants in the day-ahead market.

4.4.2 Treatment of interconnector flows resulting from market coupling

One of the outcomes of the market coupling process will be day-ahead interconnector flows between the SEM and BETTA. The mechanics of the cash flow are not currently important, but in essence, as a result of the day-ahead interconnector flows, a 'shipping agent[59]' will have a physical position on the BETTA day-ahead market (with a price set at the day-ahead stage), a physical position on the SEM ex-post market, and a CFD between SEM ex-post and day-ahead prices.

Assuming that there is a flow of energy between the day-ahead markets, the shipping agent thus has a commercial position in both markets (buying in the low priced day-ahead market and selling in the high-priced day-ahead market). From the resulting financial surplus, the 'shipping agent' should pay to the interconnector owner (in the first instance) the congestion rent. This will equal the product of the day-ahead price differential between SEM and BETTA and the amount of the interconnector flow (allowing for capacity and other charges). This congestion rent is then redistributed to holders of financial or unused physical capacity rights.

Mechanically, the shipping agent will have a firm forward physical position in BETTA (for which it must pay or receive the day-ahead BETTA price), and a CFD in the SEM for the difference between the day-ahead SEM price and ex-post SEM (energy + capacity) price. The shipping agent will be responsible for bidding the interconnector flows to the ex-post SEM, and for settlement in the ex-post pool (similar to the arrangements for any party responsible for an Interconnector Unit under the existing SEM).

The shipping agent should ideally be kept financially balanced under all circumstances. The main risk (in fact a cause for surplus) to the shipping agent is that it is exposed to day-ahead interconnector flows not being matched in the ex-post schedule (the equivalent of the imbalance risk for other day-ahead participants).

We suggest that the day-ahead interconnector flows would be treated in the same way as interconnector flows currently determined by the ex-ante run of the MSP. This means that the flow will be treated as a Dispatch Quantity (DQ) in the ex-post calculations, and the shipping agent can thereby satisfy its physical position in the BETTA day-ahead market. The interconnector will receive (or pay) capacity charges based on its flow.

If the interconnector volume is scheduled in the ex-post Pool, then its SEM settlement will be the ex-post SMP plus out-turn capacity price, and this should be fully hedged by the day-ahead CFD.

However, if the interconnector volume is not scheduled ex-post, then the shipping agent would receive a constraint payment based on its bid or offer price (which is nearly certain to be above the SMP). Therefore, it would have a net exposure to the difference between the SMP and its bid price, typically a surplus, in cases where the interconnector flow fell out of merit between day-ahead and ex-post. Any such surplus could be paid to the interconnector owner in addition to the day-ahead congestion rent, or could be returned to cover constraint costs.

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59 This could be the market coupler, the local day-ahead market operator or even a TSO.

The incentives on the shipping agent in submitting bids to the ex-post SEM are not clear, and we believe that it must follow a pre-determined formula in creating the interconnector bid prices to the ex-post calculation must be determined in advance. The desire is that interconnector flows would continue to influence ex-post SMP, as today.

4.4.3 Operation of a compensation payments mechanism

Under the 'compensation payments' approach (options B/D/F), SEMO effectively ignores the day-ahead quantities when calculating the ex-post schedule. This allows the most efficient solution to be found ex-post without being limited by the day-ahead results. Participants are then compensated for certain 'imbalance risks' which are not within their responsibility.

If price making generators have submitted a complex bid at the day-ahead stage (either to the ex-post pool and/or to the day-ahead market), SEMO will be able to calculate the cost structure of the generator. It would then be able to use the information on day-ahead volumes and price to calculate the level of compensation payment required.

The compensation mechanism would be asymmetrical. It would be used to protect market participants from losses caused by changes in volumes between day-ahead and ex-post for which they are not responsible (where appropriate as discussed in Section 2.3.7). However, it would not be expected to claw back any gains made from a difference between the day-ahead and ex-post volumes - for example, if a generator has a higher MSQ than the quantity sold day-ahead and the out-turn SMP was higher than its day-ahead price.

If some form of claw back were applied ex-post, it would effectively remove infra-marginal rent from the ex-post market, and would essentially shift the main commercial market to the day-ahead stage. In effect, this claw-back would under-reward parties that provide flexibility to help the system deal with changes between day-ahead and real-time (an extension of the present practice that infra-marginal rent is not paid on the difference between real dispatch and the ex-post schedule). This would not be desirable – within-day flexibility will become increasingly important as the amount of wind on the Irish system increases in support of environmental targets.

4.4.4 Impact on the ex-post schedule and dispatch

Fixing the day-ahead volumes (where appropriate) as price-taking generation would avoid the need for 'compensation' payments. However, increasing the fraction of generation acting as price-takers would reduce the efficiency of the SMP set in the ex-post pool and would increase constraint payments.

Generators with fixed volumes in the ex-post schedule (based on the day-ahead results) could be treated in the same way as predictable price takers in the current arrangements. This would provide a mechanism for providing generators with firm quantities, whilst allowing them to receive constraint payments if they are dispatched above their scheduled quantity.

Predictable price takers bid a full set of prices and they also bid a decremental price (which must be zero), as well as a nominated quantity. The TSO dispatches them on the basis of the full set of prices, which means that the efficiency of the dispatch decision is not restricted by the results of the day-ahead market.

In settlement, their ex-post scheduled quantity is equal to their nominated quantity (which would be the day-ahead volumes). If their dispatch quantity is above their scheduled quantity, they get constraint payments. However, if their dispatch quantity is less than the their scheduled quantity, then they still receive SMP for the full scheduled quantity (because as a price taker they have a right to be scheduled at their chosen level).

4.4.5 Further issues not considered in this paper

There are a number of more detailed points in relation to the form of generation bids into the day-ahead market, which have not been considered in this paper:

- a full and detailed list of circumstances in which it is appropriate to protect day-ahead market players from changes in volumes between day-ahead and ex-post;
- the extent to which these circumstances differ between fixing price-taking volumes (done before the ex-post run) and making compensation payments (done after the ex-post run);
- the potential distortion to bidding incentives in the ex-post SEM for participants which have fixed volumes day-ahead;
- the bidding rules for the shipping agent to the ex-post SEM;
- the treatment of any surpluses accruing to the shipping agent; and
- the identity of the shipping agent responsible for the day-ahead flow across the interconnectors – the local day-ahead market operator, a TSO or, the central market coupler.

4.5 Summary of options

We have described in detail the issues around the construction and operation of our six options. We now summarise these options with references to the key conceptual differences between them.

4.5.1 Option A: 'Price-taking volumes from a voluntary day-ahead market based on non-complex bidding'

In Option A, Irish market participants (and potentially financial players) may choose to participate in a voluntary Irish day-ahead market. If they do participate, then generation and demand must submit non-complex bids (and potentially block bids) into the local day-ahead market.

These bids are aggregated (simple bids) and/or passed on (block bids) by the local day-ahead market operator as in other European markets – this allows the complete harmonisation of the day-ahead gate closure time in the SEM with other European markets (i.e.at noon CET on D-1).

Any matched day-ahead volumes will be contracted in the form of a CFD between the day-ahead price and the ex-post price. Participants (notably those for which start-up and no-load costs are a significant factor in their bids) are exposed to the associated costs if their day-ahead costs are not correctly covered in the day-ahead auction.

As long as a specified set of criteria is met (such as generation maintains its technical availability), then the day-ahead generation volume and interconnection flows will be entered as price-taking volumes into the ex-post schedule. This should guarantee that the generators (and interconnector flows) which choose to participate will receive the full SMP in the ex-post market for day-ahead volumes (as discussed in Section 4.4.4). A CFD is then used to deliver the Irish day-ahead price to the participants in the Irish day-ahead market.

4.5.2 Option B: 'Compensation for changes from a voluntary day-ahead market based on non-complex bidding'

This option operates in the same way as Option A except for the operation of the ex-post pool. The ex-post schedule is determined without taking account the results of the day-ahead market. The results of the ex-post schedule are compared to the results of the day-ahead market to see if any parties should be compensated (according to certain limited criteria) for loss from change between day-ahead and ex-post markets. The costs of such compensation would (generally) be socialised across (some classes of) participants.

4.5.3 Option C: 'Price-taking volumes from a voluntary day-ahead market based on complex bidding'

Under Option C, Irish market participants can again choose whether or not to participate in an Irish day-ahead market (based on a CFD from the ex-post price). If they choose to participate, then generation submits complex bids on the same basis as bids into the ex-post pool. These bids are converted by a central agency into an acceptable form to be passed onto the market coupling algorithm.

The time needed to carry out this conversion (through for example a special ex-ante run of the MSP) means that the deadline for the submission of bids by generation and demand into the Irish day-ahead market may need to be up to 90 minutes ahead of the day-ahead gate closure in other European markets.

The results of the day-ahead market are entered as price-taking volumes into the ex-post pool, assuming that certain criteria are met (e.g. generator availability). This will guarantee that the generators (and interconnector flows) will receive the full SMP in the ex-post market or receive constraint payments. A CFD is then used to deliver the Irish day-ahead price to the participants in the Irish day-ahead market. These arrangements do not include (as defined) any process by which generators can be compensated if the conversion from complex to non-complex bids means that they were not contracted day-ahead when they should have been.

4.5.4 Option D: 'Compensation for changes from a voluntary day-ahead market based on complex bidding'

In Option D, a central agency again converts complex bids (from voluntary participants in a day-ahead market) into a form acceptable to the central market coupler. The time needed to convert complex bids into non-complex bids means that Irish day-ahead market participants will have to submit their bids earlier than generation and demand in other day-ahead markets.

The ex-post schedule does not take into account the results of the day-ahead market. Compensation payments are determined by a comparison of the ex-post schedule with the day-ahead market results. This is used to see if any parties should be compensated (according to specified criteria) for loss from change in volumes between day-ahead and ex-post markets.

Under this option, the compensation payments could be extended to cover any loss to generators if the conversion from complex to non-complex bids means that they were not contracted day-ahead when they should have been. This would then raise the question of how and from whom to recover the costs of these compensation payments.

4.5.5 Option E: 'Mandatory day-ahead with ex-post residual market'

This is the most radical of the six options considered, although stops short of complete adoption of BETTA-type arrangements. In the mandatory day-ahead market, a central agency has to convert complex bids from generation into non-complex bids. This means that Irish day-ahead market participants will have to submit their bids earlier than generation and demand in other day-ahead markets.

Under this approach, the SEM software would take the committed day-ahead prices and quantities as a starting point and then minimise the changes in total cost from this position (i.e. taking into account whether plants were already synchronised in the day-ahead schedule). The scope of optimisation of the SEM would be therefore to minimise the cost of deviations from the day-ahead quantities, not to minimise the cost of the whole ex-post schedule.

The existing uplift algorithm implicitly assumes that generators would not otherwise be generating and the start-up and no-load costs are always calculated as positive costs. In an alternative system in which firm prices and quantities are fixed day-ahead, then any subsequent schedule might reduce as well as increase start and no-load costs compared to the day-ahead. This could be captured in the uplift algorithm – at present the uplift algorithm considers the absolute incurred costs, whereas in future it could consider the deviation between costs incurred in the previous and the next schedule (i.e. avoided as well as incurred start costs). Therefore at times when the demand forecast falls between the day-ahead and the within-day, then some start costs would be avoided, reducing the SMP.

After the day-ahead stage, within-day pricing could continue, with a final ex-post settlement for residuals from day-ahead volumes.

The pricing of residuals may require the development of system buy and sell prices but the details of this have not been fleshed out. It would be possible to separate within-day from ex-post settlement or, for a reduced impact on the SEM systems, to bundle them.

This consequence of this option would be that interconnectors could remain integral to the price setting process and that within-day trading could be facilitated. Indeed, this option would be most effective if combined with a number of intermediate within-day steps.

4.5.6 Option F: 'Compensation based on results of mandatory day-ahead market with complex bidding'

In the mandatory day-ahead market, a central agency has to convert complex bids from generation into non-complex bids. This means that Irish day-ahead market participants will have to submit their bids earlier than generation and demand in other day-ahead markets.

The ex-post schedule does not take into account the results of the day-ahead market. Compensation payments are determined by a comparison of the ex-post schedule with the day-ahead market results. This is used to see if any parties should be compensated (according to specified criteria) for loss from change between day-ahead and ex-post markets.

Under this option, the compensation payments could be extended to cover any loss to generators if the conversion from complex to non-complex bids means that they were not contracted day-ahead when they should have been. This would then raise the question of how and from whom to recover the costs of these compensation payments.

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5. ASSESSMENT OF DIFFERENT OPTIONS

In this chapter, we assess the six options we have presented for design of an Irish day-ahead market. The chapter is structured as follows:

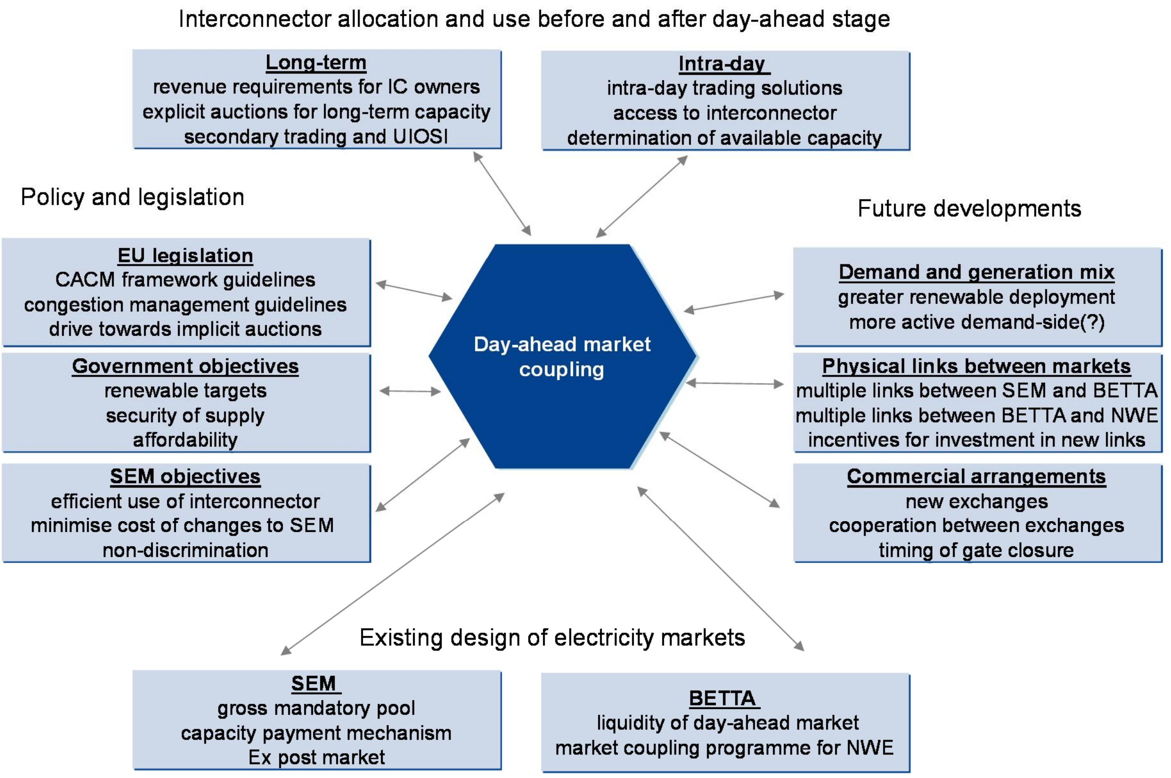
- a description of our assessment criteria which build on the objectives of the TSC itself;
- a summary assessment comparing all six options; and
- a discussion in turn of the performance of each option initially looking at its overall performance before then looking at its score against each criteria.

Given the requirement not to fundamentally alter the SEM design, we can only compare the sub-set of options consistent with that design constraint. Therefore, we have not explored other options which would require a fundamental redesign of the SEM, such as a move to the continuous bilateral trading arrangements in the BETTA market in Great Britain (GB).

5.1 Assessment criteria

The RAs will have to balance a number of objectives when evaluating different options for day-ahead market design. This is illustrated by Figure 4 which describes the links between day-ahead market coupling and the other issues that the RAs may need to take into account in their development of Irish market design.

Figure 4 – Links between day-ahead market coupling and other policy issues



This complex set of links makes it important to develop a set of criteria for assessing the day-ahead market options that are consistent with the objectives set out in the TSC. We have included an explicit requirement for compliance (in our view, subject to legal interpretation) with European developments.

Our chosen assessment criteria are:

- **promote competition** (with the RAs review of market power and liquidity in the SEM noting the expected benefits for competition from the delivery of effective day-ahead market coupling[60])
- **efficient administration of the SEM** (including cost of implementation);
- **efficient ex-post pricing** (reflecting the TSC objective regarding costs to consumers);
- **opportunities for risk management** (reflecting the TSC objective regarding costs to consumers);
- **size of compensation and constraint payments** (reflecting the TSC objective regarding costs to consumers); and
- **compliance with European developments** (subject to legal interpretation).

Using the size of compensation and constraint payments in the assessment highlights the interaction between the dispatch pattern, the ex-post schedule and the day-ahead volumes.

The SEM Committee has stated its support for the principle that the market schedule should allocate infra-marginal rent to generating units that are of value to the real time operation of the system[61]. They have proposed that constraint payments are an appropriate measure of the efficiency of the ex-post schedule as they illustrate the divergence between the ex-post schedule and operational dispatch[62].

Those design options which increase the amount of price-taking generation in the ex-post schedule (options A, C and E) effectively increase the influence of the day-ahead results on the ex-post schedule. This in turn is likely to widen the divergence between dispatch and the ex-post schedule as the day-ahead results by definition cannot take into account out-turn demand, wind and generator availability.

The other design options (options B, C, F) introduce compensation payments in order to keep parties whole as a result of differences between day-ahead and ex-post volumes (if they are not responsible for these differences)[63]. The level of the compensation payments can be seen as a possible measure of the divergence between the day-ahead volumes

60 'Market Power and Liquidity in the SEM. A report for the CER and for the Utility Regulator', Cambridge Economic Policy Associates, 15 December 2010.

61 'Principles of Dispatch and Design of the Market Schedule in the Trading & Settlement Code. A Consultation Paper', SEM-09-073, SEM Committee, July 2009.

62 'Single Electricity Market. Monitoring the Divergence of the Market Schedule from Dispatch and the Impact on Consumers', SEM-11-002, SEM Committee, January 2011.

63 In principle, this approach is similar to the concept of constraint payments in the present SEM, which guarantee infra-marginal rent for ex-post scheduled volumes which are not dispatched, and which pay compensation for dispatched volumes which are not scheduled ex-post.

and the ex-post schedule (akin to the use of constraint payments to measure the difference between the ex-post schedule and dispatch).

5.2 Summary assessment

Table 3 presents a summary assessment of the performance of the six different options:

- **Option A**: 'price-taking volumes from a voluntary day-ahead market based on non-complex bidding';
- **Option B:** 'compensation for changes from a voluntary day-ahead market based on non-complex bidding';
- **Option C:** 'price-taking volumes from a voluntary day-ahead market based on complex bidding';
- **Option D:** 'compensation for changes from a voluntary day-ahead market based on complex bidding';
- **Option E:** 'mandatory day-ahead market with ex-post residual market'; and
- **Option F:** 'compensation based on results of mandatory day-ahead market with complex bidding'.

In the table, the following scoring criteria are used:

- ✓ policy option clearly performs well against objective;
- (✓) policy option has some positives for objective;
- \- policy option has no material impact on objective;
- (×) policy option has some negatives for objective; and
- × policy option clearly performs badly against objective
- ×× policy option performs very badly against objective

The summary assessment highlights that the different options have strengths and weaknesses in different areas, with no option performing well against all criteria. Consequently, a way forward for the development of detailed policy proposals would be to assign a weighting for each criteria[64] and where possible to carry out quantitative assessment in order to help the comparison of performance across criteria. This is beyond the scope of this report.

[64] Given the importance of the weighting of the criteria, we have not reported an overall score for each option.

Table 3 – Summary assessment of options

Assessment criteria	A	B	C	D	E	F
Promote competition	-	-	(✓)	(✓)	✓	✓
Efficient administration of the SEM	✓	(✓)	(×)	×	××	×
Efficient ex-post pricing	(×)	(✓)	(×)	(✓)	×	(✓)
Opportunities for risk management	(✓)	(✓)	✓	✓	(✓)	(✓)
Size of constraint and compensation payments	(×)	(×)	×	×	(✓)	×
Compliance with European developments	(✓)	(✓)	(✓)	(✓)	(✓)	(✓)

5.3 Option A: 'Price-taking volumes from a voluntary day-ahead market based on non-complex bidding'

In summary, Option A represents the least change for the operation of the SEM. It does not result in the introduction of additional compensation payments, although it is likely to increase constraint payments. The provision of firm day-ahead prices and volumes increases the risk management options open to Irish market participants, albeit with day-ahead market participants taking on some new forms of risk. The option is believed to be broadly compliant with European developments, although there is uncertainty about the level of liquidity and effective competition it will deliver. If participation in the day-ahead market is high, this will significantly reduce the efficiency of the ex-post schedule.

This option performs well with respect to the efficient administration of the SEM. Of all the options, this one represents the least change from current operational arrangements. The main impact of the day-ahead market on the operation of the current SEM arrangements will be to increase the amount of price-taking generation in the ex-post schedule (and, therefore, constraint payments). From an administrative perspective, this should be relatively low-cost to implement (although by no means trivial).

Option A performs moderately well against opportunities for risk management and compliance with European developments. This option improves the risk management tools open to Irish market participants by providing them with access to firm day-ahead prices and volumes. However, if generators want to participate in the market, then they have to bear the risk of providing non-complex bids into the day-ahead market. If suppliers want to participate in the market, then they will be exposed to the impact of errors in the day-ahead forecast. These two factors offset (albeit not completely) the benefits of improved risk management from firm day-ahead prices and quantities.

The option is broadly compliant with European developments in that it provides an opportunity for Irish market participants to access firm day-ahead prices and quantities through price coupling arrangements. The format of bids and the gate closure times in the Irish day-ahead market should be aligned with those in other European markets. However, there remains uncertainty about how much liquidity will be delivered in practice in this voluntary market. Therefore, the option does not receive the top score on this criteria.

It is not clear whether Option A will have material benefits or disadvantages for competition in the Irish day-ahead market. The SEM Committee has acknowledged the important of concerns about market power in the design of the SEM, as a result of the existence of two large electricity incumbents. One of the mitigation tools implemented was the introduction of bidding principles alongside complex bidding and a single daily bid for fuel prices. Therefore, a move away from complex bidding to non-complex bids for the day-ahead market may raise issues about the extent to which market power can be exercised (and hidden) in the day-ahead market. This will particularly raise concerns if this feeds through into the ex-post schedule through the designation of day-ahead volumes as price-taking generation.

There are two key sources of potential mitigation of market power under this option – the choice that market players have of whether to participate or not, and impact of the BETTA day-ahead market, given that one of the aims of the RAs is for the efficient use and scheduling of the interconnectors at the day-ahead stage.

The voluntary nature of the market permits parties to arbitrage between ex-post and day-ahead and should keep the prices in line (allowing for the risk profile of each). Thus, if market power is exercised to produce excessively high (or low) prices day-ahead, then demand customers (or generation) would be expected to leave the market. Although this might mitigate the market power concern, it then may cause the development of an illiquid market.

As discussed in Section 3.2.6, there has historically been low very levels of participation in the BETTA day-ahead market. This would need to increase significantly for it to act as an effective restraint on market power in the Irish day-ahead market. The review of market liquidity by Ofgem and the integration of BETTA with the CWE markets at the day-ahead stage may help to deliver improved levels of participation.

Therefore, it is uncertain at present the extent to which this option will truly facilitate effective competition in the Irish electricity market.

Option A has some negative for the delivery of an efficient ex-post price. This is because of the designation of day-ahead volumes as price-taking generation. This will reduce the amount of price-making generation in the ex-post schedule. The delivery of an efficient ex-post market schedule and price will be very important for price-taking generation, such as wind, and for some categories of demand customers who may be less willing to participate in a day-ahead market because they cannot commit to firm volumes.

There is a trade-off here with the delivery of a liquid market (which in turn affects the criteria of competition and – in our interpretation – the degree of compliance with European developments). As the level of participation (and liquidity) in the day-ahead market increases, the price-making volumes in the ex-post schedule will fall.

5.4 Option B: ‘Compensation for changes from a voluntary day-ahead market based on non-complex bidding’

In summary, this option represents relatively little change to the operation of the SEM, especially compared to options C-F. It continues to support the efficiency of the ex-post schedule by not increasing the level of price-taking generation and interconnection.

However, this is at the cost of the introduction of additional compensation payments (which are manifested as constraint payments in option A). The provision of firm day-ahead prices and volumes increases the risk management options open to Irish market participants, although at the cost of day-ahead market participants taking on some new forms of risk. The option is broadly compliant with European developments, although there is uncertainty about the level of liquidity and effective competition it will deliver.

Option B does not score highly against any of the assessment criteria but performs moderately well in four of the six areas – efficient administration of the SEM, ex-post pricing efficiency, compliance with European developments, and opportunities for risk management.

The main change to the operation of the SEM (beyond the introduction of a voluntary day-ahead market) is the need to design arrangements for paying ex-post compensation to parties under specified criteria in relation to differences between day-ahead and ex-post volumes. The calculation and settlement of compensation payments could in theory be carried out after the production of the ex-post schedule although in practice all ex-post settlement is expected to be calculated simultaneously.

This option does not increase the amount of price-taking generation in the ex-post pool and therefore, supports the production of an efficient ex-post SMP (thus with lower constraint payments than option A). It does not receive the top score in this area because the use of simple bids in the calculation of day-ahead interconnector flows reduces the ability to use interconnector flows at the day-ahead stage to mitigate start and no-load costs. However, there is a trade-off between this and access to the wider GB market and on balance the score is positive (compared with the status quo).

The option is broadly compliant with European developments in that it provides an opportunity for Irish market participants to access firm day-ahead prices and quantities through price coupling arrangements. The format of bids and the gate closure times in the Irish day-ahead market should be aligned with those in other European markets. However, there remains uncertainty about how much liquidity will be delivered in practice in this market, and the option does not receive the top score on this criteria.

As with Option A, Option B performs moderately well against opportunities for risk management. It provides Irish market participants with voluntary access to firm day-ahead prices and volumes. However, if generators want to participate in the market, then they have to bear the risk of providing non-complex bids into the day-ahead market. If suppliers want to participate in the market, then they will be exposed to the impact of errors in the day-ahead forecast. These two factors offset (albeit not completely) the benefits of improved risk management from firm day-ahead prices and quantities. The circumstances in which compensation will be paid need to be defined as part of the detailed design stage. We have assumed that these circumstances will be well-defined in support of market transparency. If they are not, then this would reduce the risk management benefits of this option.

It is not clear whether this option will materially benefit the level of competition in the Irish electricity market. As discussed with Option A, a move away from complex bidding to non-complex bids may raise issues about the extent to which market power can be exercised in the day-ahead market, particularly if this feeds through into the ex-post schedule through the designation of day-ahead volumes as price-taking generation.

There are two key sources of potential mitigation of market power under this option – the choice that market players have of whether to participate or not, and impact of the BETTA day-ahead market, given that one of the aims of the RAs is for the efficient use and scheduling of the interconnectors at the day-ahead stage.

In a voluntary market, then if market power is exercised to produce excessively high (or low) prices, then demand customers (or generation) would be expected to leave the market. Although this might mitigate the market power concern, it then may cause the development of an illiquid market.

The illiquidity of BETTA is a constraining factor on the promotion of competition, as for option A.

Finally, Option B scores badly (like all of the options except Option E) in relation to the size of compensation and constraint payments because it introduces the scope for market participants to be compensated to keep them financially whole for changes between the day-ahead and ex-post markets.

5.5 Option C: 'Price-taking volumes from a voluntary day-ahead market based on complex bidding'

In summary, this option scores strongly on improving the opportunities for risk management for Irish market participants. It performs moderately well with respect to compliance with European guidelines and promotion of competition. However, it performs relatively weakly on cost of changes to the operation of the SEM, and the delivery of efficient ex-post pricing. Finally, it scores badly on the size of compensation and constraint payments.

Option C is the best-performing option (jointly with Option D) in terms of improving opportunities for risk management. It gives Irish market participants voluntary access to firm day-ahead prices and volumes. Generators are able to provide complex bids into the day-ahead market, with a central agency bearing the risk of converting them into acceptable bids for the central market coupler. If suppliers want to participate in the market, then they will be exposed to the impact of errors in the day-ahead forecast. However, they retain the choice of whether or not to participate.

The option is broadly compliant with European developments in that it provides an opportunity for Irish market participants to access firm day-ahead prices and quantities through price coupling arrangements. The opportunity for generation to provide complex bids may help also market liquidity, which helps to boost the performance of this option against the criteria of increasing competition.

However, the format of bids and the deadline for submission of bids by Irish market participants may be misaligned with those in other European markets. This is because generators can submit complex bids, which will take some time for the central agency to turn into a format suitable for the central market coupler.

The man weaknesses of Option C are in relation to the efficiency of the ex-post price, the cost of introducing changes into the operation of the SEM, and the likely cost of constraints and compensation.

This option will increase the amount of price-taking generation (and interconnection) in the ex-post schedule. This increases the importance of day-ahead scheduling in the ex-post schedule, hence increasing the gap between dispatch and the ex-post schedule (and therefore increasing constraint payments). In addition, compensation payments may rise to keep generators whole in situations where they have been disadvantaged by the way in which the central agency has turned complex bids into non-complex bids.

There is a trade-off here with the delivery of a liquid market (which affects the criteria of competition and compliance with European developments). As the level of participation (and liquidity) in the day-ahead market increases, the price-making volumes in the ex-post schedule will fall.

The requirement for a central agency to convert complex bids into non-complex bids will represent a significant change to the operation of the SEM and is likely to be very complex. This will increase the costs and riskiness of market operation, hence pushing up administrative costs.

5.6 Option D: 'Compensation for changes from a voluntary day-ahead market based on complex bidding'

Option D performs most strongly on improving the opportunities for risk management for Irish market participants. It also performs moderately well with respect to supporting efficient ex-post pricing, compliance with European guidelines and promotion of competition. However, it scores badly on cost of changes to the operation of the SEM, and the introduction of additional compensation payments.

As with Option C, this option gives Irish market participants voluntary access to firm day-ahead prices and volumes. The risk of converting complex bids into non-complex bids is borne by a central agency rather than by generators. Although suppliers (and wind generation) will be exposed to the impact of errors in the day-ahead forecast, participation is voluntary and so they can decide whether the rewards outweigh that risk.

Option D does not increase the amount of price-taking generation in the ex-post pool and therefore, supports the production of an efficient ex-post SMP.

The option is broadly compliant with European developments in that it provides an opportunity for Irish market participants to access firm day-ahead prices and quantities through price coupling arrangements. As with Option C, the opportunity for generation to submit complex bids may help also market liquidity, which helps to boost the performance of this option against the criteria of increasing competition. However, this also means that the format of bids and the deadline for submission of bids by Irish market participants may be misaligned with those in other European markets.

The worst performing areas for Option D are the introduction of new compensation payments and the administrative costs for the SEM.

This option effectively introduces two forms of compensation payments:

- one designed to keep participants financially whole with respect to differences between day-ahead and ex-post volumes for which they are not responsible; and
- one designed to compensate generators who have been disadvantaged by the way in which the central agency has turned complex bids into non-complex bids.

Under this option, there has to be significant changes to the operation of the SEM (and hence associated administration costs) with respect to the conversion of complex bids into non-complex bids by a central agency, and the need to design arrangements for paying ex-post compensation to parties under specified criteria in relation to differences between day-ahead and ex-post volumes.

5.7 Option E: 'Mandatory day-ahead with ex-post residual market'

In summary, this option scores strongly on increasing competition at the day-ahead stage. It performs moderately well with respect to compensation payments, opportunities for risk management and compliance with European guidelines. However, it performs badly for the delivery of efficient ex-post pricing and in particular, the cost of changes to the SEM.

Mandating participation will by definition deliver a highly liquid Irish day-ahead market, supported by the retention of complex bidding. Combined with the use of implicit auctions (so that interconnection capacity is effectively available to the whole market), this should improve the efficiency and scheduling of the use of the interconnector at the day-ahead stage. This is similar to the benefits of the 'use it or lose it' provision embodied in the two ex-ante gate closures that would be introduced in the proposed intraday modification.

Option E gives all Irish market participants access to firm day-ahead prices and volumes. Generators are able to provide complex bids into the day-ahead market, with a central agency bearing the risk of converting them into acceptable bids for the central market coupler. However, market participants are not able to choose whether or not to participate in the market, which means that they cannot control their exposure to changes from the day-ahead stage onwards. This means that the option only scores moderately well on the criteria of risk management.

The option is the only one to receive a positive score for performance on compensation and constraint payments. It does not use compensation payments to keep market participants financially neutral for changes between day-ahead and ex-post markets. Constraint payments would not be a material feature of this approach, as the within-day issues would be captured in (more extreme) ex-post prices. However, compensation payments may need to be introduced to keep generators whole in situations where they have been disadvantaged by the way in which the central agency has turned complex bids into non-complex bids.

Option E is broadly compliant with European developments in that it provides an opportunity for Irish market participants to access firm day-ahead prices and quantities through price coupling arrangements. Although a mandatory market will be highly liquid, it is not consistent with the approach of voluntary day-ahead markets that is used in other European markets. In addition, the provision of complex bids by generators means that the format of bids and the deadline for submission of bids by Irish market participants may be misaligned with those in other European markets.

This option would introduce perhaps the most radical changes to the SEM (of the options considered), which means that it scores very badly with respect to reducing the costs of operating the SEM. It will introduce a mandatory day-ahead market, with changes to the nature of the ex-post optimisation, which will take day-ahead prices and quantities as a starting point and then minimise the changes in total cost from this position (i.e. taking into account whether plants had already incurred start-up costs).

Consequently, Option E will change the nature of the ex-post price in the SEM as it will be related to residuals rather than to the whole market schedule. Therefore, the option scores relatively badly on the criteria of the efficiency of the ex-post price. However, it does not receive the worst score possible (××) as the residuals should be efficiently priced.

5.1 Option F: 'Compensation based on results of mandatory day-ahead market with complex bidding'

In summary, this option scores strongly on increasing competition at the day-ahead stage. It performs moderately well with respect to the efficiency of ex-post pricing, opportunities for risk management and compliance with European guidelines. However, it performs badly on the level of constraint and compensation payments and the cost of changes to the SEM.

As with Option E, the combination of a mandatory (and hence liquid) day-ahead market with the use of implicit auctions should significantly improve the efficiency and scheduling of the use of the interconnector at the day-ahead stage.

Under this option, Irish market participants get access to firm day-ahead prices and volumes. Generators are able to provide complex bids into the day-ahead market, with the central agency bearing the risk of converting them into acceptable bids for the central market coupler. However, market participants are not able to choose whether or not to participate in the market, which means that they cannot control their exposure to changes from the day-ahead stage. This means that the option performs only moderately well on the criteria of improved risk management.

There is no increase under this option in the amount of price-taking generation in the ex-post pool and therefore, it supports the production of an efficient ex-post SMP.

Option F gives Irish market participants an opportunity to access firm day-ahead prices and quantities through price coupling arrangements. However, the option is assessed to perform only moderately well with respect to compliance with Europe because mandating participation does not necessarily fit with the European model. In addition, the use of complex bids into the local day-ahead market means that the format of bids and the deadline for submission of bids by Irish market participants may be misaligned with those in other European markets.

This option scores badly with respect to the level of compensation payments. These may be paid to participants to keep them financially whole with respect to differences between day-ahead and ex-post volumes for which they are not responsible. These payments could be much larger with mandatory day-ahead participation as more parties could be affected. However, this may be offset by a reduction in compensation payments (if they are paid in this circumstance in other options) caused by differences in participation between the day-ahead and ex-post markets.

In addition, there is the possibility of compensation payments for generators who have suffered loss as a result of the conversion by the local market operator of complex bids into non-complex bids.

Under Option F, there must be significant major changes to the operation of the SEM with respect to:

- shift to a mandatory day-ahead market;
- the conversion of complex bids into non-complex bids by a central agency; and
- the introduction of ex-post compensation arrangements (under specified criteria) in relation to differences between day-ahead and ex-post volumes.

Consequently, this option scores badly on the criteria of efficient administration of the SEM.

ANNEX A – EVOLUTION OF EUROPEAN MARKET COUPLING

A.1 Overview

Recent years have seen a drive towards greater integration of European electricity markets at the day-ahead stage with developments such as:

- the move to the pentalateral (price) coupling of the Central Western Europe (CWE) market, covering Germany, France, the Netherlands, Belgium and Luxembourg;
- the interim tight volume coupling (ITVC) between the CWE and Nordic markets;
- the development of implicit auctions across the (forthcoming) 'Britned' link between GB and the Netherlands.

The ITVC between the CWE and the Nordic markets was launched across the German-Danish interconnection on 9 November 2010 to coincide with the start of the pentalateral coupling arrangements in CWE. On 12 January 2011, the ITVC was extended to cover the NorNed link between Norway and the Netherlands.

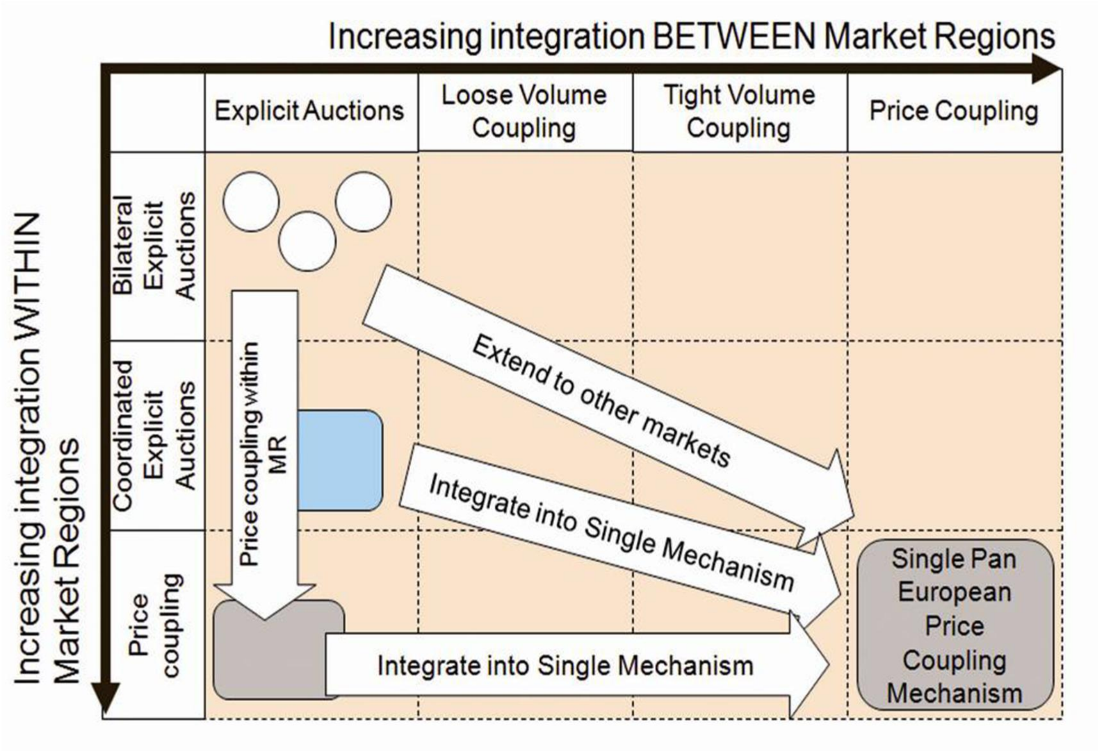
Over the past year, the focus of European discussions on integration at the day-ahead stage have moved to a much stronger emphasis on *price coupling* at the day-ahead stage (in which day-ahead market prices in each market are set jointly with interconnector flows).

Day-ahead price coupling is a key feature of the *target model* for market integration that underpins the draft Framework Guidelines on capacity allocation and congestion management ("Framework Guidelines") issued in September 2010[65]. The Framework Guidelines will inform binding network codes to be developed by ENTSO-E over the next two to three years. The network codes for day-ahead and intraday are expected to be developed first with finalised versions scheduled to be issued by Q1 2012. The development of the network codes covering the forward market and capacity calculation will happen a little slower, with completion of the final version of the code scheduled for Q3 2012.

Figure 5 shows how under the target model, the introduction of volume coupling arrangements is seen as an intermediate milestone in the progression towards price coupling, first within market regions and then across Europe.

[65] 'Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (Ref: E10-ENM-20-03)', 8 September 2010, issued by ERGEG in place of ACER.

Figure 5 – Overview of target model



Source: Ad-Hoc Advisory Group (AHAG)

At the same time, there are two commercial initiatives looking to extend the scope of price coupling for electricity markets in NWE:

- the TSO-driven project for full day-ahead price coupling across NWE (covering CWE, Nordic markets and BETTA); and
- the price-exchange led project, the Price Coupling of the Regions (PCR), which includes NWE as well as Iberia and Italy.

The relevance of these initiatives for the SEM has been heightened by the increasingly active role played by GB in participating in these initiatives, in light of increased links between BETTA and other European electricity markets (e.g. 'Britned').

A.2 Market coupling initiatives by industry parties

There are two market coupling initiatives being led by industry parties that would involve NWE – one led by the TSOs and one led by power exchanges (PCR).

Both initiatives expect to have an enduring market coupling solution in place by the end of 2012 (with the TSOs hoping to complete by Q1 of that year). They share a number of common features, including gate closure timing and definition of stakeholder roles. The proposed timing for the day-ahead gate closure is noon CET on the previous day, which would be equivalent to a gate closure of 11am in the SEM. The trading day is for a 24 hour period (one hour intervals) starting at midnight CET (11pm Irish time).

There are four key stakeholders in each design, who have the following roles (as summarised in Figure 6):

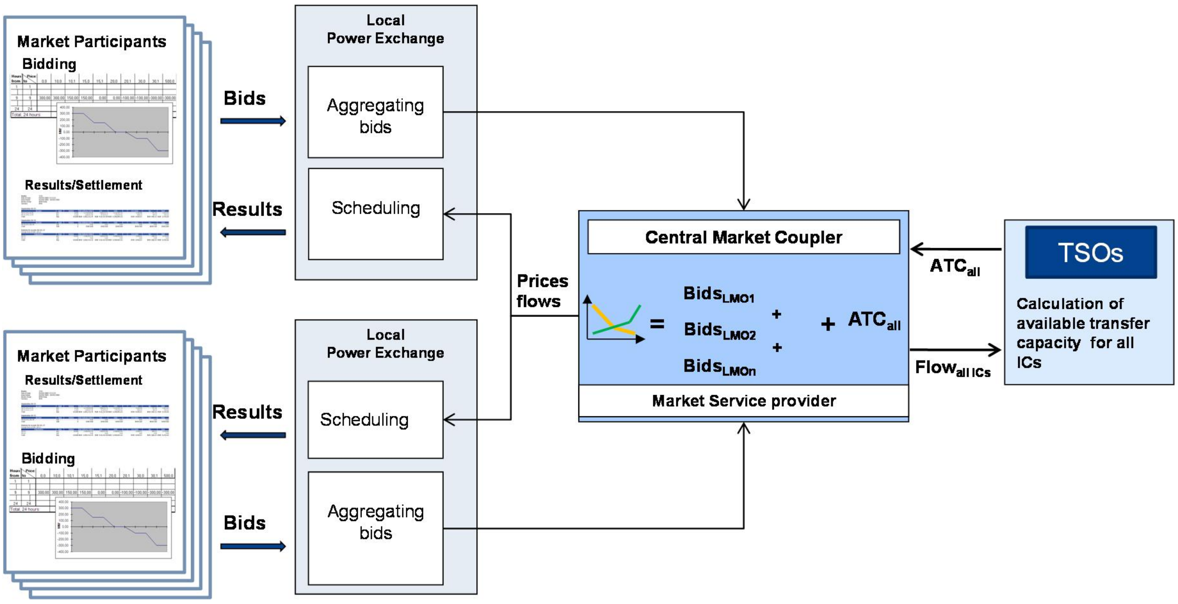
- **Market players;**
  - submit bids (simple or block) to local power exchange on voluntary basis;
  - receive firm prices and quantities from local power exchange;
- **Local power exchanges;**
  - gather bids and offers (simple and block) for local market[66] (with an obvious need to ensure liquidity);
  - turn simple bids into a net export curve (NEC)[67] for sending to central market coupler;
  - pass (anonymised) block bids directly to central coupler;
  - are responsible for dealing with local legal, regulatory and governance issues;
- **Central market coupler;**
  - gathers NEC and block bids from local exchanges[68];
  - collects available transfer capacity (ATC) from TSOs to determine interconnection capacity available for use by the central coupler in the day-ahead market;
  - provides local power exchanges with results on which bids and offers have been accepted;
- **TSOs;**
  - provide central market coupler with all ATC at day-ahead (i.e. total available capacity minus any flows nominated by long-term capacity holders before the day-ahead stage); and
  - facilitate flows.

66 It is possible to have more than one local exchange for a market, as shown by BETTA where there are currently two power exchanges operating.

67 A net export curve for hour *h* gives the potential net export (based on hourly orders) from a market at each possible market price. This is a specific form of an aggregated bids and offers curve. In the rest of this report, the term NEC is used to denote an aggregated bids and offer curve.

68 This process requires the definition of common data exchange parameters and common rules on acceptable bid parameters.

Figure 6 – Overview of market coupling processes



There are some differences between the initiatives but these relate more to implementation than to high-level design:

- **leadership** – whether it is the TSOs or the power exchanges;
- **geographical coverage** – the PCR initiative extends to include Italy and Spain; and
- **governance** of the central market coupler.

The TSOs envisage that the central coupler will be operated by the power exchanges, but as a monopoly activity that is clearly distinguished from their other non-regulated activities. Under the PCR model, the central coupler function will be rotated round a number of the power exchanges (that have put in place the required systems).

At the moment, the PCR process is currently defining the block bids that can be put into the central algorithm, which should be completed early in 2011. As yet, no bidding options have been rejected and the following options are all under consideration:

- standard block bid;
- profiled block bid (quantity differs across hours);
- linked block bids (whether complementary or mutually exclusive);
- minimum income bids (based on Italian requirements) – this may have a similar effect to complex bids;
- schedule stop and load gradient bids (again based on Italian system).

As the PCR parties are still in progress of finalising algorithm design, power exchanges will need to consider how to manage the risk that increasingly complex block bids increase the risk of non-unique solutions from the market coupling process.

ANNEX B – PRICE AND VOLUME COUPLING

B.1 Overview

Market coupling is the process of joining together different market areas with the purpose of using implicit auctions to determine interconnector flows. The main benefits of implicit auctions include:

- more efficient use of interconnection capacity;
- more efficient price discovery through greater liquidity in day-ahead trading; and
- reduced need for wheeling of bilateral contracts in which the generator and the customer are not in countries that are not directly interconnector (e.g. as would happen if an SEM generator was able to strike a bilateral contract with a customer in France).

There are two broad types of market coupling arrangements – price coupling, and volume coupling (which can itself be described as either 'tight' or 'loose').

B.2 Price coupling

Price coupling is based on a single algorithm that uses bid/offer information from each market and the available cross border capacities. The algorithm jointly establishes prices, generation volumes and interconnector flows for each coupled market, and takes into consideration all bids/offers from all markets.

An example of day-ahead price coupling is the Central Western European Market Coupling (CWE), which includes Belgium, the Netherlands, France, Germany and Luxembourg. This means that day-ahead market prices in each of these countries are determined in parallel to those in other CWE countries, according to an agreed algorithm[69].

Market participants submit their purchase or sales orders by midday (12.00pm CET) for each hour of the following day (starting at midnight CET). All potential trades are then aggregated by hourly periods and ranked according to price. For each hour, the intersection of the aggregated supply and the aggregated demand curve determines the market results (i.e. the market clearing price and the market clearing volume).

After this fixing is performed, the market results are made available to participants. When there is insufficient interconnection capacity to ensure price equality across region, then markets decouple and more than one price emerges. Contracts are then created which require participants in the each country to deliver to, or to withdraw, from the network they are connected to the volume of electricity in accordance with their contracts.

The price coupling of the CWE builds on the day-ahead trilateral coupling (TLC) involving the Netherlands, Belgium and France that started operation on 21 November 2006.

Between 2007 and 2009, the day-ahead prices in these three countries were identical 62% of the time on an average basis. Table 4 shows the proportion of hours in which there were identical prices in at least two of the markets.

[69] http://www.apxendex.com/uploads/tx_abdownloads/files/COSMOS_public_description.pdf

Table 4 – Price convergence under TLC

	2007	2008	2009
Single price between France, Belgium and Netherlands (as a % of traded hours)	60%	70%	57%
Price convergence between France and Belgium	85%	85%	70%
Price convergence between Belgium and Netherlands	72%	84%	85%

Sources: Belpex, EPEX and Pöyry Energy Consulting analysis

B.3 Volume coupling

Under volume coupling arrangements, the coupling system uses a single algorithm to determine the flows across the interconnectors between the underlying regions/markets, based on anonymous bid/offer information from each market. The algorithm partly replicates the matching rules of each coupled market.

However, the **day-ahead** price in each market is still determined separately by the local power exchange which uses the generated cross-border volumes to locally determine their bidding area(s) prices and volumes. As a consequence, there is the potential that should the out-turn prices deviate from those estimated in the market coupling process, the interconnector flows may not be consistent with the resulting day-ahead prices.

The difference between tight and loose volume coupling relates to the degree of replication of local market rules and the level of indicative bid/offer information used. Loose volume coupling allows the coupling of two markets which have significant differences in local rules, without the need for major and substantial changes to either market.

Under loose volume coupling, the difference between the market design used to determine the interconnector flows and used to determine the market prices can frequently lead to cases whereby the interconnector flows are not always consistent with final prices.

This was seen in the initial difficulties faced by the loose volume coupling between Denmark and Germany. Discrepancies between the market coupler's results compared with the results from the individual power exchanges resulted from the combination of the loose volume coupling methodology with an illiquid market in Denmark. The issues were resolved by the introduction of tighter volume coupling arrangements, which better reflect the market rules and algorithms of the coupled markets.

ANNEX C – DETAILED DESIGN COMPARISON OF SEM AND OTHER NWE MARKETS

This Annex provides a more detailed comparison of the design of the SEM and other markets in North West Europe (NWE), which is defined for the purposes of this report as covering BETTA, the Nordic market and the Central West European (CWE) market (which includes Germany, France, Belgium, the Netherlands and Luxembourg).

The Annex is structured in line with the summary provided in Table 2 in Section 3.2:

- number of physical markets;
- form of agreed generation bids;
- market schedule and design;
- timing of gate closures; and
- composition of wholesale prices.

Each section starts with a description of the SEM design before then looking at the design of the NWE markets for the same aspect of the market.

C.1 Number of physical markets

C.1.1 Number of physical markets – SEM

In the SEM, virtually all trade of physical electricity (with limited exceptions) is conducted through the gross pool with compulsory participation for all licensed generators above 10MW and suppliers.

In a gross pool, all participating generators/suppliers receive/pay the same system marginal price (the SMP) for the electricity sold into/bought via the pool. The SMP is determined via the Market Scheduling and Pricing (MSP) Software, which is run by the market operator after the trading day in question. This means that the market schedule can take account of actual demand, generation availability and output from price-taking generation (primarily wind), as opposed to using the forecast levels available at the day-ahead stage.

Generators (other than those with priority dispatch, which are entitled to act as 'price takers') must submit bids for use in calculation of the market schedule, and their scheduled volumes are determined centrally by an optimisation algorithm. When combined with the requirements of the licence and Bidding Code of Practice to bid in line with short-run marginal costs and submit technical offers which are accurate (i.e. based on physical not commercial factors), the centralised schedule calculation leaves generators with limited ability to influence their scheduled production profile.

Actual dispatch may differ from the (unconstrained) market schedule for a range of reasons. Compensation for this 'out of merit' dispatch is at generator bid prices, which (through application of the Bidding Code of Practice) are in line with short-run marginal costs.

As a consequence, the principal source of value within the energy market (**capacity payments aside**) is through access to the market schedule, and physical dispatch has less commercial significance. In economics terms, only the ex-post market (and any prior financial trading) permit generators to earn '*infra-marginal rent',* i.e. prices in excess of their own (short-run) operating costs.

As virtually the whole market is settled ex-post, there is no concept of a firm ex-ante market (other than the limited financial trading which occurs), and parties effectively cannot capture infra-marginal rent at the day-ahead stage (even though bids into the pool are actually submitted at a day-ahead gate closure).

Interconnector flows are fixed at the day-ahead stage based on an initial run of the MSP software, but the interconnector units are treated as price makers in the ex-post market schedule, and are only paid their bid/offer price (rather than the SMP) if they are not scheduled in the ex-post calculations. This is a near-example of 'loose volume coupling' in action; the interconnector flows are set independently of the price calculations, using the same price data but with revised information on generation availability, wind and demand. As a consequence the interconnector flow is sometimes inconsistent with the (eventual) market price.

There is a payment of 'uninstructed imbalances' for dispatchable generation under the SEM but in principle its application is limited. Suppliers do not face the charge, and it is intended to be levied in case of failure to follow dispatch instruction rather than in the event of unforeseen generator failure (since the ex-post schedule uses the out-turn availability for each generator).

A modification to the Trading and Settlement Code (TSC)[70] is currently being progressed which would create an intra-day gate closure to allow the within-day (re)allocation of interconnection capacity. This allows the ex-post schedule to take into account changes in (for example) fuel prices after the day-ahead stage. However, it does not change the fundamental nature of the SEM as an ex-post market.

As well as allowing intra-day (re)allocation of interconnection capacity, the proposed modification will introduce a 'use it or lose it (UIOLI)' provision for interconnection capacity at the day-ahead stage. The modification has been developed in response to the infringement proceedings brought by the European Commission for Moyle not complying with the existing guidelines for managing congestion on interconnection (Annex to 2006/770/EC).

C.1.2 Number of physical markets – NWE

The design of electricity markets in NWE is based around the operation of different **(voluntary)** physical markets open to participants across a continuum of time frames:

- **Forwards markets,** which allow electricity contracts to be struck from several years ahead right up toclose to real-time. These offer hedging opportunities through either exchanges or bilateral trades between generators, suppliers, traders and customers.
- **Day-ahead auctions**, which produce firm day-ahead prices and quantities in line with the Framework Guidelines on capacity allocation and congestion management.
- **Intra-day trading**, which allows parties to adjust their positions in response to events that happen after the day-ahead gate closure.
- **Balancing Mechanism,** which operates from the intra-day gate closure and allows participants to voluntarily submit bids and offers for deviation from their contracted quantities to the system operator.

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70 Mod_18_10. Intra-Day Trading in the SEM.

Day-ahead prices and quantities can be considered to be firm because a generator has the ability to self-schedule against its contracted volume. These volumes are used as a starting point for any subsequent trades in the within-day or balancing markets.

Submission of bids and offers into the balancing mechanism is voluntary. Generators have the right to capture additional value (infra-marginal rent) by trading in and out of the market in different timescales.

The choice between markets allows participants to choose the timing of trading to best meet their risk needs. Therefore, gas operators with a variable position in the merit order may choose to trade gas and power relatively close to delivery, whereas nuclear generators may choose to trade further in advance. Similarly, extremely flexible plant operators may choose to trade predominantly in the within-day or balancing markets where their flexibility may be fully captured, and flexible demand participants which need a minimum notice period to schedule consumption might trade no later than day-ahead.

There is a mandatory imbalance settlement process under which participants are charged if their contracted positions (net of balancing mechanism adjustment) do not match their metered volumes of electricity. Unlike the SEM, these imbalances are levied on the difference between the volumes notified at gate closure (adjusted for balancing trades) and the actual volumes delivered; they represent a substantial risk to suppliers and variable generators, as well as generators subject to short-notice trips.

Figure 7 and Figure 8 provide an overview of the different markets in operation in the Nordic power market and in the Dutch power market respectively. These show each of the markets described above – long-term financial markets, day-ahead auctions, intra-day trading and the balancing market.

The day-ahead market in the Netherlands is operated by APX Power NL and is designed to allow market participants to achieve a balance of their purchase and sale portfolios on an hour-by-hour basis. It is essentially based on a two-sided auction model, with trading taking place on one day for delivery the next day. Market members submit their order electronically to APX Power NL. On the basis of submitted bids, demand and supply are compared on a daily basis, and a merit order is compiled. The intersection of supply and demand results in a price for each hour for delivery the next day – this is the APX Power NL day-ahead price index.

Figure 7 – Overview of Nordic wholesale market arrangements

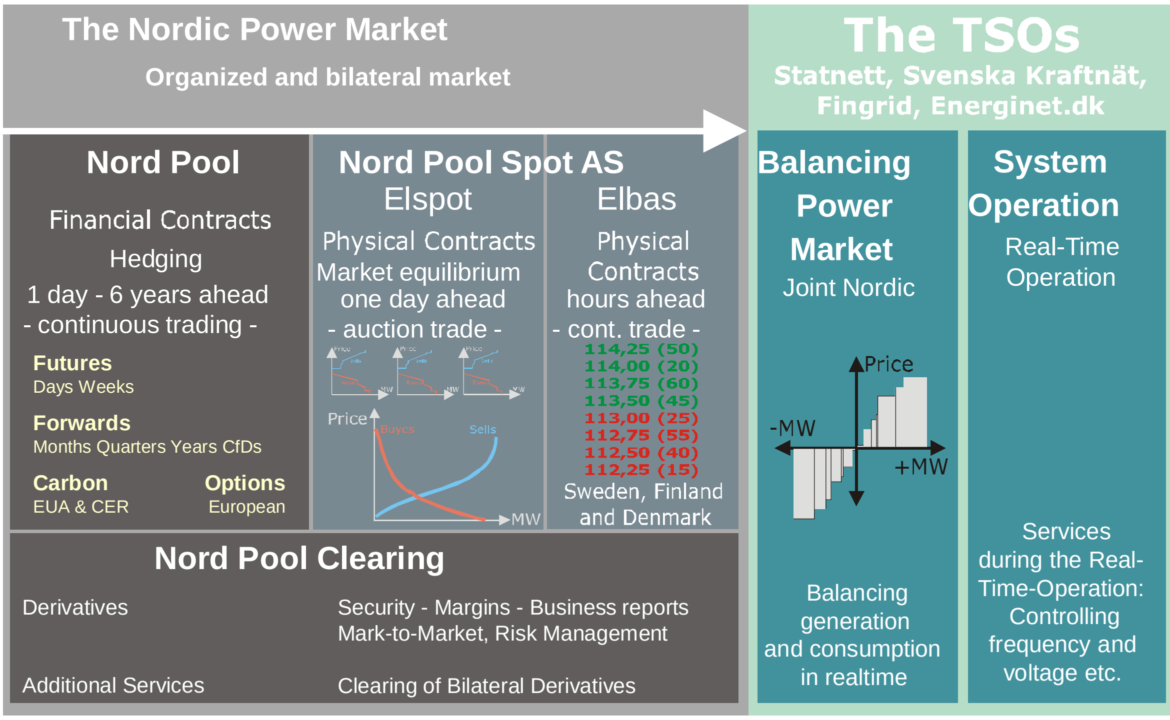
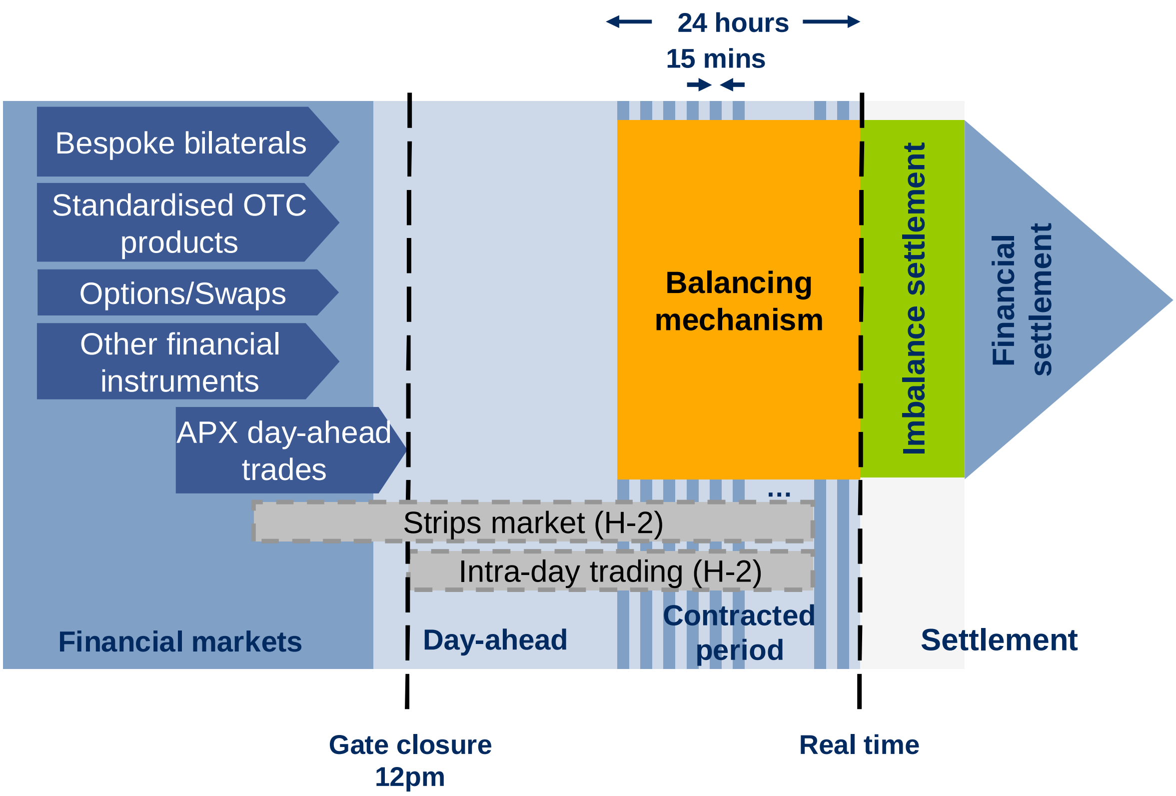


Figure 8 – Overview of Dutch wholesale market arrangements



C.2 Form of generation bids

C.2.1 Form of generation bids – SEM

In the SEM, price-making generators submit one complex bid for each generation unit for each trading day. This can include up to 10 (monotonically increasing) price-quantity pairs based on a single energy price for the whole day along with no-load cost[71] and warmth-dependent start-up costs[72]. These bids are subject to detailed bidding principles to ensure that, as far as possible, they reflect the structure of generation costs.

Interconnector units submit bids in the form of price-quantity pairs for each half-hour with no allowance for start-up or no load costs. Other 'special' generator units (including pumped storage, reservoir hydro and demand side bidders) have bespoke bidding rules.

These bids are used in a central optimisation process run by the market operator to minimise total cost of meeting demand, given the volume available from price-taking generation. The optimisation uses a 36 hour period, with the schedule day running from 6am Irish time (7am CET).

Generation bids into the SEM are in the local currency, £ sterling for generators in Northern Ireland and € for those in the Republic of Ireland. Only generation submits bids to the SEM, and demand (other than demand side bidders) are passive.

C.2.2 Form of generation bids – NWE

In the NWE electricity markets, generation bids are non-complex, certainly up until the start of the balancing mechanism. A non-complex bid takes the form of a €/MWh bid that covers a combination of energy, start-up and non-load costs. The non-complex bid can be a simple bid or a block bid.

A simple bid covers the operation of the generator in a single hour. For example, in the Dutch market, simple bids are defined as a 'set of freely-definable consecutive hourly instruments' (also known as Spot Block Orders). Therefore, the generator faces the risk of spreading the start-up and no-load costs over the unknown energy volumes.

If they spread the cost over too much volume, they may not recover all of their no-load and start-up costs if their bids are accepted but for a lower volume. Alternatively, if they spread the no-load and start-up costs over too low a volume then their bid may be too high to be accepted in the day-ahead market, and hence they may not be scheduled to operate even if their underlying generation costs were lower than some of the contracted generation.

One way of managing this risk is to submit a block bid, which combines bid prices and volumes for a consecutive number of single hours. If the bid is accepted, the generator will run for all of the specified hours rather than a subset.

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71 The no load cost is the element of operating costs that is invariant with the actual level of output, expressed in £ or €/hour.

72 Start-up costs are the costs associated with starting the generator from cold, warm or hot states.

There are a number of different forms of block bids, with different markets having different rules for what type is acceptable:

- standard block bid;
- profiled block bid (quantity differs across hours);
- maximum payment conditions (buy side) or minimum income conditions (sell side); and
- linked block bids (whether complementary or mutually exclusive).

In practice, the complex bids used in the SEM arrangements are another form of block bid, but they are much more detailed than those in use in other European energy markets.

Typically, the bids into the balancing market reflect the cost of changing from the contracted level of generation, rather than the cost of delivering different levels of generation. Therefore, they can be considered to be more complex than the bids submitted in the ex-ante markets but are still much less complex than the bids used in the SEM.

C.3 Market scheduling and dispatch

C.3.1 Market scheduling and dispatch – SEM

The TSC recognises several distinct types of generator units for the purposes of deriving the ex-post schedule in the SEM. Table 5 below presents the five generic settlement classes for Generator Units and the distinctions between them.

Table 5 – Generator Units – generic settlement classes

Question 1		Question 2		Question 3	Priority dispatch? If so, then option:	
					No	*Yes*
					Price Maker	Price Taker
Dispatchable?	*Yes*	Variable?	*No*	Predictable	Predictable Price Maker Default	Predictable Price Taker (Priority Dispatch only)
			Yes	Variable Wind or run-of-river hydro	Variable Price Maker	Variable Price Taker (Priority Dispatch only)
	No		*n/a*	Autonomous Not dispatchable	N/A	Autonomous

Source: Trading and Settlement Code, SEM at http://www.allislandproject.org/en/trading-settlement-code-decision.aspx

The ex-post run of the market software in the SEM calculates the Market Schedule Quantity (MSQ) for each price-making generation unit for each trading period, required to provide sufficient generation to meet demand. The ex-post market schedule is based on an unconstrained system, i.e. ignoring within-half-hour requirements, transmission constraints and the requirements for reserve, frequency response or system inertia.

In practice, the system operators must dispatch generators taking transmission system constraints and reserve requirements into account (and must also consider real-time issues on the system such as unplanned outages). Therefore, the actual dispatch schedule followed is likely to deviate from the ex-post market schedule.

With the exception of autonomous and non-market generation, all Generator Units will be subject to central dispatch instructions from the relevant SO. 'Variable' generators (wind and run-of-river hydro) may be turned down, and price taker generation may be dispatched at a different level to its nominated quantity (which is included in the ex-post schedule).

The only price or quantity fixed in the day-ahead market schedule is the flows across the interconnector between SEM and BETTA. Interconnector units receive a semi-firm price, whereby they receive (or pay) the SMP if they are in the ex-post schedule, and their bid or offer price if they are out of merit in the ex-post schedule. In the latter case, this means that it captures no infra-marginal rent. In either case, they receive (or make) capacity payments based on the actual flow rather than the quantity in the ex-post schedule.

C.3.2 Scheduling of generation – NWE

In other markets in North West Europe, there is effectively self-dispatch of generation based on contractual positions (as submitted at the intra-day gate closure) and any bids and offers accepted in the balancing mechanisms.

With respect to interconnectors, parties can nominate flows against their holdings of long-term physical capacity rights (where these exist as there are no long term capacity rights in the Nordic market). Nominations can be submitted up to the day-ahead stage when 'use it or lose it provisions' typically apply (in line with the existing congestion management guidelines).

The system operator uses the balancing mechanism to minimise the costs of balancing their system (e.g. in response to deviations from the contracted positions), as opposed to minimising total system cost (as in the ex-post SEM arrangements).

C.4 Timing of gate closure

C.4.1 Timing of gate closure – SEM

Under the current SEM arrangement, gate closure for the submission of bids into the gross pool currently occurs day-ahead at 10am for a trading day starting at 6am (7am CET) the next day. Consequently there is a long gap (of up to 44 hours) between the submission of bids and the end of the trading period. This extended period is designed to help the system operators to maintain control of a small island system (and to minimise trading costs). The long gate closure is mitigated by the fact that the out-turn demand, wind and generator availability are used to calculate the market schedule.

Although this gap would be reduced by the introduction of a within-day gate closure under the proposed SEM intra-day modification, the gap between the within-day gate closure and the trading window will still be ten hours. This is much longer than the comparable period in the NWE markets.

C.4.2 Timing of gate closure – NWE

The standard time for day-ahead gate closure is 12pm (CET) on the previous day in most of the NWE markets, for a day commencing at midnight CET. This is then followed by a series of intra-day gate closures, at which participants must submit their contracted positions and any bids and offers for the balancing mechanism.

The timing of the intra-day gate closure can vary across markets but is usually close to real-time. For example, in BETTA, intra-day gate closure occurs one hour before delivery, for each half-hour trading period in succession. In the Dutch market, gate closure is two hours before delivery.

C.5 Composition of wholesale prices

C.5.1 Composition of wholesale prices – SEM

The SEM provides generation and demand with separate prices for energy and capacity.

The SMP for a trading period is set equal to the sum of shadow price and uplift, within the limits of the price cap (€1000/MWh) and price floor (-€100/MWh) set by the RAs. The shadow price reflects the cost of the marginal MW required to meet demand in a trading period based on an unconstrained schedule. The uplift component recovers (under normal circumstances) operating costs associated with start up costs and no load costs of all generators that appear in the ex-post schedule.

Payments for capacity are made under a separate mechanism under which generators are paid for their availability, irrespective of actual generation. Capacity charges are levied on suppliers based on their metered consumption in each half hour. The price of capacity for generation and (separately) demand differs between half hours, with the revenue targeted to those periods when capacity is most valuable to the system.

The total value of capacity payments in each year and its division into monthly totals (based on demand forecasts) are determined in advance by the Regulatory Authorities. The annual total is calculated as the product of the annual cost per kW of a best new entrant peaking generator (net of expected receipts from ancillary services and net energy revenue) and the total kW of capacity required to meet the all-island generation security standard (allowing for outages and an assumed wind capacity credit). Thus, from year to year, the overall value of capacity is not (heavily) dependent on the short-term level of system margin, but instead is intended to represent a long-term equilibrium.

Within each month, for capacity payments to generators, the breakdown of the monthly total into half hours is based on the three elements set out below (in addition, the resultant capacity prices for each generator are adjusted by the level of SMP and/or the level of the generator bid price):

- a ‘fixed’ element (30%) set before the beginning of each year, based on the demand forecast for each half hour;
- a ‘variable’ element (40%) set out before the beginning of each month based on a system margin forecast and a conversion to a calculated ‘loss of load probability’; and
- an ‘ex-post’ element (30%) set out at the end of each month, based on a simplified loss-of-load probability estimate using outturn data.

The calculations for capacity charges to suppliers are more straightforward, and are singularly dependent on the ‘fixed’ element. These values are determined by the market operator in advance of the capacity period in each year and are therefore far more predictable (and less responsive to system conditions) than the generator capacity payments.

Generation capacity prices cannot be calculated accurately for any trading period until after the end of the calendar month concerned. The profile (and average level) of capacity prices for generation and demand differs within-month. Interconnector units are settled as generation for the purposes of capacity payments, whether importing or exporting.

C.5.2 Composition of wholesale prices – NWE

At present, there is no explicit separation of energy and capacity in the wholesale prices seen in the North West European electricity markets. Therefore, the price is described as an 'all-in' price for energy and capacity.

A number of European markets, including France and GB, are planning to introduce more explicit capacity mechanisms into their market design. However, these capacity mechanisms will not necessarily be based around a separate capacity payment for the whole market as in the SEM. For example, the capacity mechanism in France may be based around a capacity obligation on suppliers.

The Electricity Market Reform (EMR) proposals for BETTA discuss the introduction of a targeted capacity mechanism (CPM). However, the stated intention is that the energy-only price formation within the wholesale market will be retained, and there will be an attempt to prevent the targeted CPM from influencing imbalance, spot or forward prices.

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ANNEX D – SCOPE OF WORK

This Annex sets out the original terms of reference for this report. It then describes how the required scope of work was narrowed to reflect the limit on the resources available for this project

D.1.1 Original terms of reference

In April 2010, the CER and the Utility Regulator issued a tender for expert economic and technical advice on how best a day-ahead price in a pool market such as the SEM can be established.

The key issues to be addressed in this work package include:

- 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?
- Can the SEM learn from experiences of market coupling in other markets (e.g. the Trilateral Market Coupling area, CWE, Denmark-Germany)? Wider European developments in this area (European Commission and ERGEG reviews) must be considered, as outlined in relevant SEM papers ref: SEM-10-011 and SEM-09-096.
- If market coupling is deemed to be best achieved through the daily auctioning of CfDs, how could 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 using ex-ante prices be in practice?
- What are the links between proposed solutions emerging from the Modifications Committee on intra-day trading on the one hand and the proposed solution on a day-ahead price solution for SEM on the other? Would the two be compatible? If not, how could they be made compatible?
- 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?

This contract was a call-off contract for a maximum of 30 days of consultancy. Given this limit on project resources, the RAs agreed to narrow the scope of the project to the following

- (a) develop feasible end-to-end policy options for day-ahead trading in the SEM beginning with the NWE and PCR market coupling projects and examining how there market coupling between these and the SEM pool market might be achieved;
- (b) assess the compatibility of these policy options with the existing market(s) framework (including intra day);
- (c) assess the identified options; and
- (d) production of summary note(s).

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