Integrated Single Electricity Market (I-SEM)

High Level Design for Ireland and Northern Ireland from 2016

Consultation Paper

5 February 2014

SEM-14-008

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1 PURPOSE OF THIS DOCUMENT

1.1 PURPOSE AND STRUCTURE OF THIS DOCUMENT

1.1.1 This Consultation document forms part of the process for implementing a new High Level Design (HLD) for the Integrated Single Electricity Market (I-SEM) in Ireland and Northern Ireland by the end of 2016.

1.1.2 This document consists of the following elements:

- An update on the process for reaching a decision on the implementation of a new HLD in the SEM (Section 2).
- A description of the main physical and commercial characteristics of the SEM that need to be taken into account in the revised HLD (Section 3).
- A discussion of four distinct options for the HLD for energy trading arrangements, including a qualitative assessment of each option against the HLD criteria (Sections 4 to 9).
- A description of possible approaches to the explicit remuneration of capacity that can be used to support any of the proposed options for the high-level trading arrangements (Section 10).
- Confirmation of the next steps in this consultation process, including a collated list of all of the consultation questions (Section 11)
- Background material on the issues discussed in the other chapters, including a glossary, list of abbreviations and further reference documents (Sections 12 to 14).

1.1.3 The following consultation questions relate to the major issues discussed in this document:

1. Which options for energy trading arrangements would be your preferred choice for the I-SEM, and why?

2. Is there a requirement for a Capacity Remuneration Mechanism (CRM) in the revised HLD, and why?

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

1.2 ENERGY TRADING ARRANGEMENTS

1.2.1 This document discusses the main topics and subtopics to be addressed in any HLD for energy trading arrangements to comply with the European Electricity Target Model (hereafter this will be referred to as the 'EU Target Model').

1.2.2 The paper then describes four distinct HLD options for energy trading arrangements. It addresses each option in turn in terms of description (covering underlying

philosophy and how each option addresses the design topics) and a qualitative assessment of each option against the HLD criteria confirmed in the "Next Steps Decision Paper" (SEM-13-009) published by the SEM Committee in February 2013.

1.2.3 The qualitative assessment is done with consideration for each option on its own rather than comparatively against the other options for energy trading arrangements. This reflects that each option has strengths and weaknesses in different areas, and a key part of reaching the decision on the preferred HLD will be how easy (and important) it is believed to be to address any identified weaknesses within the option.

1.2.4 The SEM HLD criteria are:

- **Security of supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- **Stability:** the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.
- **Practicality/Cost:** the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced.
- **Equity:** the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner.
- **Competition:** the trading arrangements should promote competition between participants; incentivise appropriate investment and operation within the market; and should not inhibit efficient entry or exit, all in a transparent and objective manner.
- **Environmental:** while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.
- **Adaptive:** The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.
- **The Internal Electricity Market:** the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.

When considering which HLD option to take forward for implementation, the SEM Committee will be guided by its primary objective (as confirmed in the February 2013 Next Steps Decision Paper) that: *" is to protect the interests of consumers of electricity in Ireland and Northern Ireland supplied by authorised persons, where appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity though the Single Electricity market".*

1.2.5 This will inform the emphasis placed by the SEM Committee on performance of an option against each of the HLD criteria.

1.2.6 We specifically seek feedback through the consultation process on the qualitative assessment, as it should be informed by the expertise of a wide range of stakeholders. For example, the views of the Transmission System Operator (TSO) will be important in assessing the performance of the options against the security of supply criteria, as they can provide insight into the information, time and tools that it may need to deliver a safe, secure and efficient dispatch.

1.2.7 At this stage, it is important to recognise that there is scope to amend the specific design of each option as a part of the feedback given through the consultation process. Any refinements should however not alter the overall objective of the option.

1.3 CAPACITY REMUNERATION MECHANISMS (CRMs)

1.3.1 This document describes a number of possible approaches to Capacity Remuneration Mechanisms (CRMs), which are considered independently of the options for the HLD of energy trading arrangements. This is because each of the four HLD options described in this paper for energy trading arrangements can work with a variety of CRMs (including no CRM).

1.3.2 The design of a CRM (if required) should take into account developments in neighbouring countries and the (draft) requirements of European State Aid Guidelines, as well as the energy trading arrangements in the SEM.

1.3.3 The Draft Decision Paper on the HLD will present recommendations on the design of both energy and capacity markets (where required) as a package. This will follow, amongst other things, consideration of responses to the consultation and advice of the TSOs on generation adequacy in the context of revised EU State Aid Guidelines for the energy sector. This detailed examination will include analysis of the need for, and particular features required by, a capacity remuneration mechanism.

1.4 CONVENTIONS IN THIS DOCUMENT

1.4.1 All of the options presented in this document can be applied to one or several zones within the SEM. Therefore, nothing in this document should be interpreted as presuming the outcome of any future reviews of zoning carried out under the requirements of the EU Target Model. If any wording in this document implies the use of a single zone, this is unintentional.

1.4.2 Similarly, any use of the term ‘interconnector’ in reference to energy trading arrangements under the EU Target Model should be interpreted as referring to capacity between two price zones.

2 PROCESS FOR THE DEVELOPMENT AND IMPLEMENTATION OF A NEW HLD

2.1 PROGRESS TO DATE ON THE EUROPEAN MARKET INTEGRATION PROJECT

2.1.1 The creation of an internal market for electricity, one of the key pillars of the European single market, has been given fresh impetus by the European Union's Third Energy Package. This requires implementation of the EU Target Model that will harmonise cross-border trading rules.

2.1.2 In Ireland and Northern Ireland the Department of Communications, Energy and Natural Resources (DCENR) and the Department of Enterprise Trade and Investment (DETI) respectively have charged the SEM Committee (SEMC) with responsibility for developing trading arrangements that will be compliant with the EU Target Model.

2.1.3 In March 2013 the two Governments endorsed the recommendation in the "Next Steps Decision Paper" (SEM-13-009) published by the SEMC in February 2013 that the SEMC should proceed to develop a High Level Design of the wholesale market arrangements on the island of Ireland.

2.1.4 The Next Steps Decision Paper also set guidelines for the HLD which were endorsed by DETI and DCENR. These included a set of principles that underpin the SEM, and which will form criteria by which a new design will be assessed, and assumptions as to the components of the HLD. The latter include an assumption of centralised commitment, later amended by the SEMC to allow consideration of self-commitment options; priority dispatch of renewable generation; the avoidance of double payments in any Capacity Payment Mechanism and the specific governance arrangements for the project.

2.2 DEVELOPMENT OF THIS CONSULTATION PAPER

2.2.1 The Project Team together with Pöyry Management Consulting[1] have been working on the design of potential options for the I-SEM by identifying the Topics of market design. These were developed into coherent alternative options for energy trading arrangements that could be compared and assessed resulting in an initial listing of nine options, three of which were excluded at an early stage.

2.2.2 Of the remaining six options, four options have been developed in sufficient detail to issue for stakeholder views in this Consultation Paper. These options are each considered viable for implementation at this stage, given the criteria set out for the revised HLD.

[1] Pöyry Management Consulting has been appointed to provide consultancy advice to the RAs on the revision of the HLD.

2.2.3 Consideration of the options has been assisted by industry and consumer stakeholders in the High Level Design Review Group, which has met on four occasions[2]. The Review Group has contributed its knowledge and experience in considering the options and has identified areas that have required clarification and development.

2.2.4 The decision to develop four options fully has been informed by discussions with the Review Group but has been determined by the assessment of the Project Team and Project Board and by the decisions of the SEM Committee.

2.3 SCOPE OF THIS CONSULTATION PAPER

2.3.1 This paper presents four possible options for the energy trading arrangements in the I-SEM. Each option is presented in terms of the underlying philosophy behind its operation and a description of how it will work in the different market time frames.

2.3.2 There is also an initial qualitative assessment for each option, which should not be read to constitute an initial ranking of the options. Its purpose is to draw out some initial features and assist those responding to the consultation to arrive at and set out their own assessments.

2.3.3 Consultation responses will inform further review and assessment of the four options and from these it is expected that a single option will be selected to take forward for further consideration and consultation.

2.3.4 A more detailed and deeper assessment of the selected option will be set out in the Proposed Decision Paper. The Final Decision Paper will take account of this further consultation and will also contain an impact statement in line with best practice

2.3.5 The Consultation Paper discusses alternative CRMs but does not propose a specific mechanism for each of the options for energy trading within the market design options.

2.3.6 The Draft Decision Paper on the HLD will present recommendations for both the design of the energy market and any CRM as a package. This will be assessed against the HLD principles. Any CRM proposed for inclusion with the revised HLD will need to be compatible with the European Commission guidance on State Aid for Generation adequacy.

2.3.7 It is important to appreciate that what is being consulted on in this paper are options for a HLD and that more detailed elements that are also necessary mechanisms of any market will be addressed in the next phase of the Regional Integration Project.

[2] The agenda and materials discussed for each meeting of the High Level Design Review Group can be found at http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=dac49400-fed7-41e7-ad9c-17c8ea4c65f4.

2.3.8 As set out in the February 2013 Decision Paper, the new HLD must facilitate a sufficiently robust market power mitigation strategy. This means that while it will not be necessary in the HLD phase to consider and determine detailed market power mitigation measures, it is important to understand to what degree such measures are consistent with and can be included within each option.

2.4 INTERACTION WITH THE DS3 PROJECT

2.4.1 The design of a new wholesale energy market will need to take account of the mechanisms for delivery of and payment for other system services and products. The Delivering a Secure Sustainable System (DS3) project[3] encompasses a review of system services to ensure that these would be available to meet the challenges arising from a high proportion of renewable and non-synchronous generation on the system.

2.4.2 Both the Market Integration and DS3 projects will need to be aware of the potential impact of changes in market and service provision design to the complete set of electricity markets. This is to ensure that services that might be rewarded as a result of DS3 are captured in the HLD of the I-SEM so that consumers are not at risk of paying twice for the same services.

2.5 TIMETABLE FOR THE IMPLEMENTATION OF A NEW HLD

2.5.1 The timetable for development of the HLD includes this Consultation, which will be shared with the European Commission and Agency for the Cooperation of Energy Regulators (ACER) so that the SEMC can be assured that options for consideration are compliant with the EU Target Model.

2.5.2 It is expected that a Proposed Decision Paper will be published in June 2014 and will present the considered design option that will be further consulted upon. A Final Decision Paper will be published in August 2014.

2.5.3 Following completion of the High Level Design phase, the detailed design stage will involve drawing up detailed rules for the market including:

- rules for trading and settlement (including credit cover and collateral)
- treatment of transmission losses and constraints
- detailed design of CRMs; and
- specific market power mitigation arrangements.

2.5.4 This will be managed to ensure introduction of the I-SEM by end-2016. Parallel with this it will be necessary to ensure that steps to implement the new market are taken,

[3] Further information on the DS3 project is available at http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=06c22cd8-a936-426b-ac21-ed28b5292566, or at http://www.eirgrid.com/operations/ds3/

including the development of systems and procedures by market participants, including the TSOs.

2.5.5 To the extent that some of the proposals in this Consultation Paper would, if adapted, require primary legislation in either or both jurisdictions, it is not the intention of the SEMC to anticipate the outcome of that legislative process. This will be discussed further with the Departments in both jurisdictions as the project progresses.

3 CONTEXT FOR THE DESIGN OF THE ALL ISLAND ELECTRICITY MARKET

3.1.1 In this Chapter, we consider the main features of the all island Market that will need to be taken into account in revising the High Level Design. This will help to ensure that, as far as possible, the revised HLD will deliver the greatest benefits for consumers on the island of Ireland (in line with the overall objective of the SEM Committee).

3.1.2 The February 2013 Next Steps Decision Paper summarised the view of the SEM Committee and market participants that the SEM has performed well to date against its statutory objectives by delivering consumers prices that are reflective of the long run cost of producing electricity.

3.1.3 It is timely to review the design of the all island market for electricity given the changes seen since the creation of the SEM which will have been in operation for over nine years by the end of 2016. These changes include:

- Increased DC interconnection capacity with the British electricity market, with the potential maximum export capacity from the all island market rising from 80MW to 950MW.
- A changing generation mix, with much greater penetration of wind today, and targets for renewable electricity penetration of around 40% by 2020.
- The opportunities for closer integration of the all island market with the European Internal Electricity Market offered by compliance with the requirements of the EU Target Model[4].
- Greater potential for more active involvement of the demand side in the all-island Market.

3.2 SUMMARY DESCRIPTION OF THE ALL ISLAND MARKET

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

3.2.2 The costs of start-up and part-loading generation are important in the All-Island Market. This is because it is a small market with a high penetration of wind and a relatively large swing in demand within the day between peak and off-peak hours.

3.2.3 Management of transmission and system security constraints are an important aspect of the SO dispatch process in the SEM. This leads to differences between the ex-post market schedule and the SO dispatch[5].

[4] Chapter 11 provides a list of reference documents which describe the requirements of the EU Target Model.

[5] Dispatch Model for the All Island Market/ Transmission System, November 2012

3.2.4 This reflects the importance of non-energy related issues such as system inertia and frequency response in managing small synchronous island systems with high levels of penetration of wind generation. In addition, there are locational issues resulting from constraints on the transmission system (e.g. in the North-South corridor).

3.2.5 Concerns about the scope for market power were an important driver of the design of the SEM. The degree and scope of market power can change over time, as a result of changes such as build and closure of generation, increased physical interconnection, the move to day-ahead and intraday market coupling as part of compliance with the EU Target Model, and increased participation by the demand side in the electricity market.

3.2.6 Therefore, the new HLD for the All-Island Market should not be determined by an assessment of market power. Rather it should facilitate robust market power mitigation measures, which could form part of the detailed specifications of any HLD.

3.2.7 There is a policy target of 40% renewable generation in both Ireland and Northern Ireland by 2020. This renewables target will largely be delivered by wind, which will pose particular challenges for market design and for system operation.

3.2.8 The Regulatory Authorities (RAs) in Ireland and in Northern Ireland have recognised the potential economic and environmental benefits of greater demand side management. This could be facilitated by changes such as the roll-out of smart metering, new forms of electric demand, and aggregation of distributed generation and storage.

3.2.9 The benefits of greater demand side management could include avoided investment in peaking plant, lower curtailment of wind, support for system services, and possible mitigation of market power (both on a system-wide basis and a local basis).

3.3 SIZE OF THE ALL-ISLAND MARKET

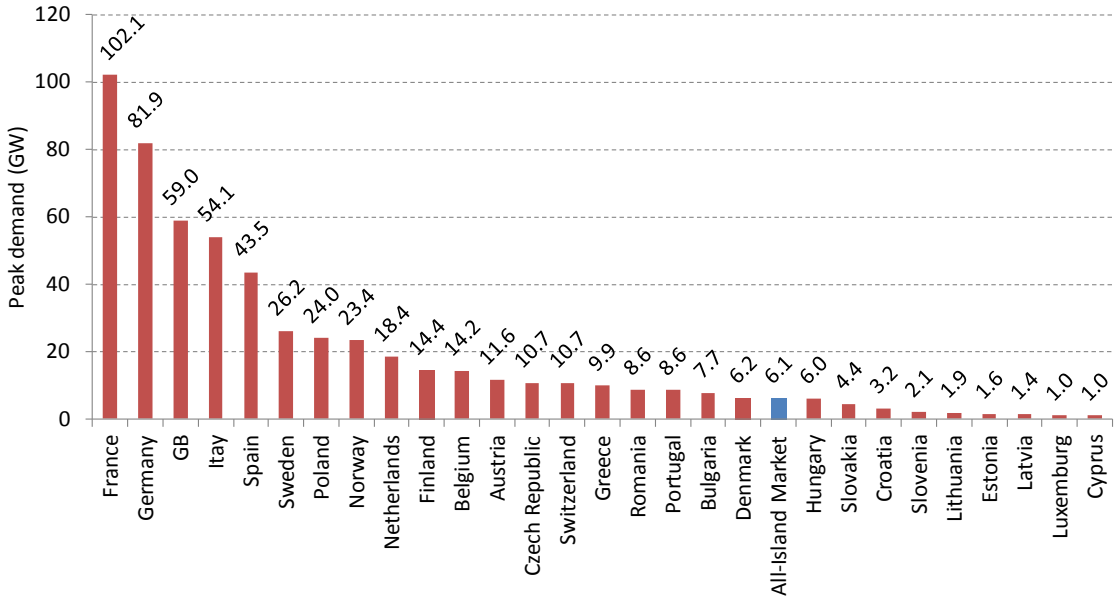
3.3.1 Peak demand in the SEM reached 6.2GW in 2012 with total annual electricity demand of 34.5TWh[6] (equivalent to average hourly demand of 3.9GW).

3.3.2 Figure 1 compares the level of peak electricity demand in the SEM with that in a number of selected European markets. It illustrates that the SEM is one of the smaller electricity markets in the EU, with the only other smaller markets either being:

- Small island systems with no external interconnection – Malta and Cyprus
- Part of the synchronous area of continental Europe with AC interconnection capacity with neighbouring countries[7] – e.g. the Baltic states, Slovakia, Hungary, Luxemburg, Croatia and Slovenia.

[6] https://www.entsoe.eu/data/data-portal/consumption/

Figure 1 – Peak demand of selected European markets in 2012[8]



Source: ENTSO-E data for all EU markets apart from the SEM; SEMO data for the SEM

3.3.3 As a small system, there has historically been concern in the constituent markets forming the All-Island Market about the sensitivity of the capacity margin to plant entry and exit, due to the size of generating units relative to the overall system. The concern was that the addition of a single Combined Cycle Gas Turbine (CCGT) generator (the expected type of market entrant) could tip the market from shortfall to surplus where it would remain for a number of years.

3.3.4 As a result of these concerns that an energy-only market would not guarantee generation adequacy for a small island system[9], an explicit CRM was a core requirement of the initial HLD for the SEM published in June 2005. As noted by the Regulatory Authorities in the SEM in the Capacity Payment Mechanism Options Design Paper in 2005, *'we are concerned at the potential volatility of energy market prices, and recognise that a key challenge for a generator who wishes to enter the market is to convince prospective lenders that the investment risk can be evaluated, and that the risk is reasonably low….the intention for a CPM then, is for a mechanism providing for capacity adequacy through economic signals that are directly meaningful to the investment decisions of generators and to the decisions of demand side participants. These economic signals should lead to socially efficient decisions on new investments, on maintenance of existing capacity and on demand response'*.

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7 The all island market forms a separate synchronous area with only DC interconnection capacity with GB. The maximum potential capacity of this interconnection recently increased to around 1GW with the commissioning of the East-West Interconnector (EWIC).

8 https://www.entsoe.eu/publications/statistics/yearly-statistics-adequacy-retrospect/

9 High demand growth post liberalisation led to capacity shortages and threats to supply security in the previous Transitional market arrangements in Ireland (which also incorporated a capacity element in the imbalance prices) prior to the introduction of the SEM in 2007.

3.3.5 The CRM was designed to provide a separate remuneration for capacity and limit the volatility in energy prices. In doing so, it was intended to allow the operation of the SEM to minimise end-user risk by dampening price volatility. This was designed to provide more stable signals for long term investments in new capacity.

3.3.6 The operation of the Short-Run Marginal Cost (SRMC) bidding principles in the SEM means that it would not be consistent to remove the current CRM without making changes to the SRMC bidding rules.

3.3.7 Since 2005 when the decision was taken to include capacity payments within the current SEM HLD, there has been an increase in generation capacity as well as significant increase in interconnection capacity with the commencement of EWIC increasing the potential total export interconnector capacity to GB to 950MW. Furthermore, some proposed new generation projects are smaller than CCGT scale (400MW).

3.3.8 The January 2013 All-Island Generation Capacity Statement (2013-2022) projected a generation surplus out to 2022 on an unconstrained All-Island Market basis. This is partly as a result of the increased penetration of wind generation and the continuing impact of the financial crisis in 2008 on load.

3.3.9 However, the UR together with DETI are progressing supplementary measures in relation to transmission constraints to help secure additional generation capacity to address a potential risk to security of supply in Northern Ireland[10].

3.3.10 For system operation, the relativity of the largest infeed to the system size results in system imbalances (e.g. caused by plant failure) having a more pronounced effect on the system when compared to other larger systems.

3.3.11 The TSOs' paper on the Dispatch Model for the all island market published as part of the draft SEM Committee Next Steps Decision in November 2012 sets out a useful comparison of the relative size and granularity of the SEM with the wholesale market in GB[11]. This paper notes that the largest infeed as a percentage of minimum demand on the GB system is approximately around ten times the size of that SEM. The largest infeed as a percentage of minimum demand on the All Island Study is 20% while in the GB market it is only 7%.

3.3.12 In addition, the paper states that imbalances between overall supply and demand have a greater impact on system frequency on the All-Island system than for the GB system. For example, a 24MW imbalance would result in a 0.2Hz frequency change

[10] 'Security of Electricity Supply in Northern Ireland. An updated information paper from the Utility Regulator and the Department of Enterprise, Trade and Investment', 9 December 2013.

[11] http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=5dc5e905-db0a-4cde-b3bb-5cf9b1873559&mode=author

on the All-Island system, whereas for the same frequency change to take place on the GB system the imbalance would have to be 240MW.

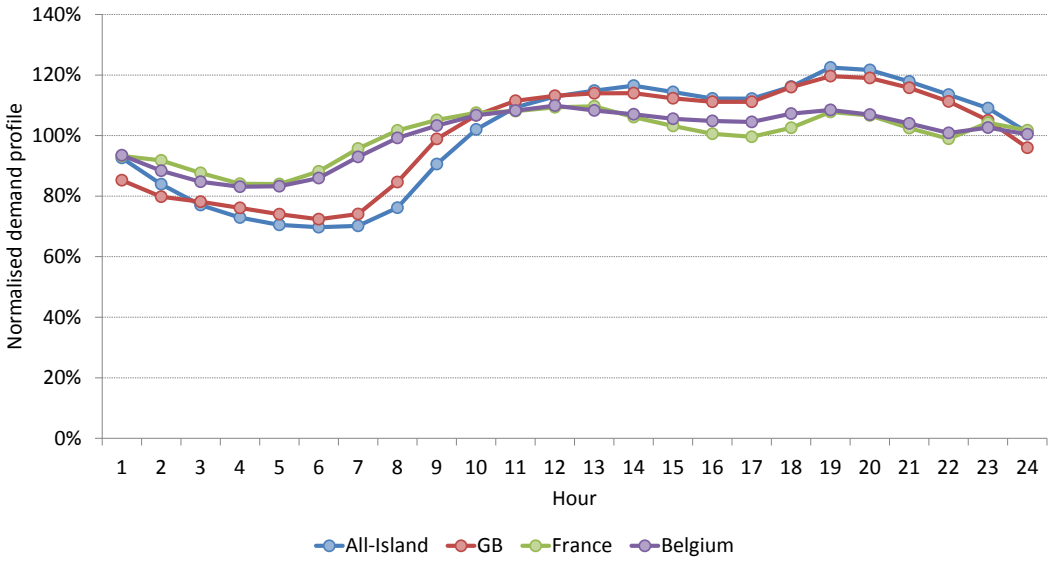
3.3.13 As a consequence, the relativity of the largest infeed to the system size in the case of a plant trip places greater importance on system services such as frequency response and system inertia.

3.4 IMPORTANCE OF STARTS AND PART-LOADING

3.4.1 The small market size and the relatively large within-day swing in demand in the SEM combined with increased levels of intermittent wind on the system increase the relative importance in the SEM of the start-up, shut-down and part-loading of generation plants.

3.4.2 The relatively low level of industrial load connected to the all-island system means that overnight (off-peak) demand is relatively low compared to peak demand. This is demonstrated in Figure 2, which compares the average shape of hourly demand in the SEM in 2012 with GB, France and Belgium. Higher industrial demand in France and Belgium means that on average there is a relatively smaller swing in demand between peak and off-peak hours in these markets than in the SEM and GB.

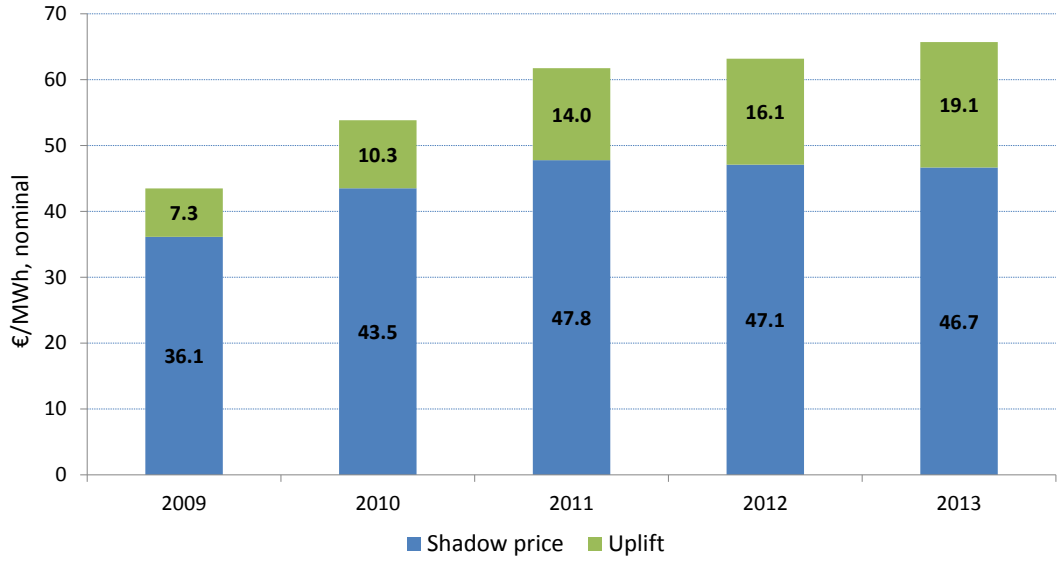
Figure 2 – Average hourly demand in 2012



Source: ENTSO-E data for GB, France and Belgium; SEMO data for the All-Island system

3.4.3 The start-up and part-loading (no-load) costs are currently recovered in the SEM through the uplift calculation. Uplift has become a larger component of the overall System Marginal Price (SMP) over the last few years as shown in Figure 3. In 2013, uplift accounted for 29% of the SMP in 2013. In itself this does not indicate a problem, but it does indicate the importance of the Uplift calculation in the determination of the wholesale costs to consumers.

Figure 3 – Contribution of the shadow price and uplift to the SMP in the SEM



Source: SEMO data

3.5 IMPORTANCE OF NON-ENERGY FACTORS IN MANAGEMENT OF THE ALL-ISLAND SYSTEM

3.5.1 The management of transmission and system security constraints are an important aspect of the SO dispatch process in the SEM. As these are 'non-energy' factors that are not included in the market schedule, there is currently a significant difference between the ex-post market schedule and the SO dispatch.

3.5.2 The difference between the ex-post market schedule and the SO dispatch is demonstrated in Figure 4, which shows the extent to which plants were re-dispatched (in both directions) away from their scheduled quantities between 2010 and 2013.

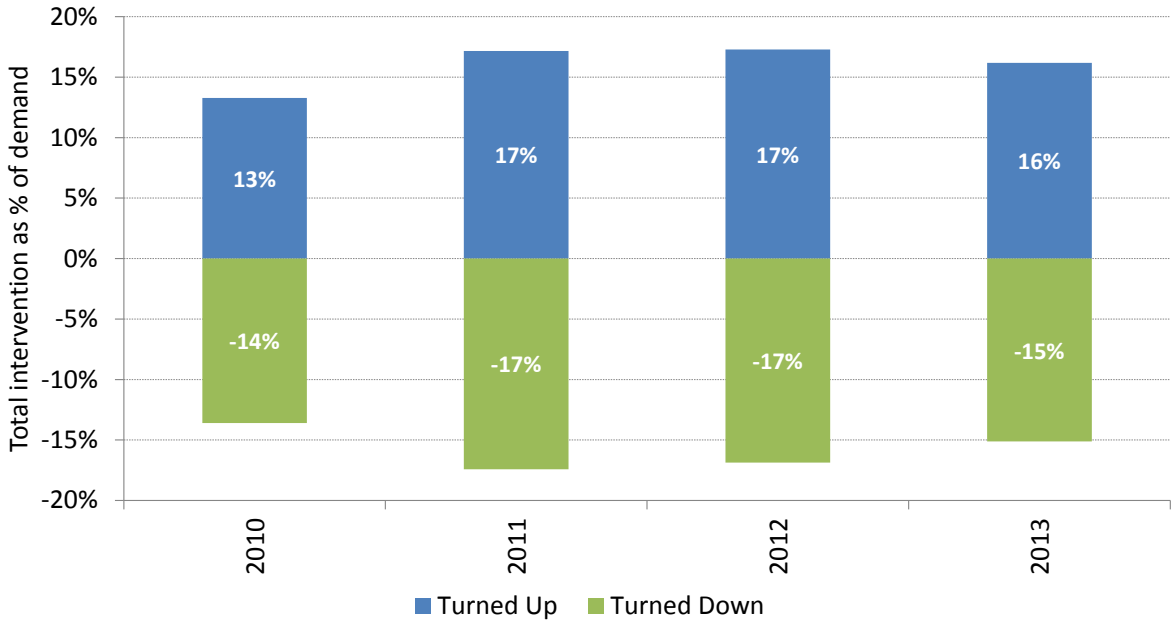
3.5.3 In part (as noted above), this reflects the fact that non-energy related issues such as system inertia and frequency response are typically of greater importance in managing small synchronous island systems (particularly with higher levels of penetration of wind generation) than for larger 'continental' systems.

3.5.4 In addition, there are locational issues resulting from constraints on the transmission system that restrict the ability to transfer electricity from generation to demand. In particular, there is currently a transmission constraint on the North-South corridor with expected reinforcement after 2017.

3.5.5 The DS3 programme[12] encompasses a review of system services to ensure that these would be available to meet the challenges arising from a high proportion of renewable and non-synchronous generation on the system.

3.5.6 The physical characteristics of the All-Island Market means that the system services framework implemented under the DS3 programme could have a big impact on the need for TSO intervention in response to the scheduled position of plants based on the energy market.

Figure 4 – Difference between schedule and dispatch



Source: Analysis based on SEMO data

3.6 MARKET POWER

3.6.1 Concerns about the scope for market power were an important driver of the HLD of the SEM, including the reliance on a transparent and liquid ex-post pool, as well as a robust market power mitigation strategy.

3.6.2 The February 2012 Market Power & Liquidity Decision Paper[13] reported analysis suggesting that market power in the SEM would not be at levels of concern on average out to 2020 but that there would still be certain hours or scenarios where the relevant metrics suggested market power potential. On that basis, it was decided that a robust market power mitigation strategy should be maintained.

12 Further information on the DS3 project is available at http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=06c22cd8-a936-426b-ac21-ed28b5292566, or at http://www.eirgrid.com/operations/ds3/

13 http://www.allislandproject.org/en/market_current_consultations.aspx?article=682a98fe-9c18-4c73-8fa3-57e75d24d85e

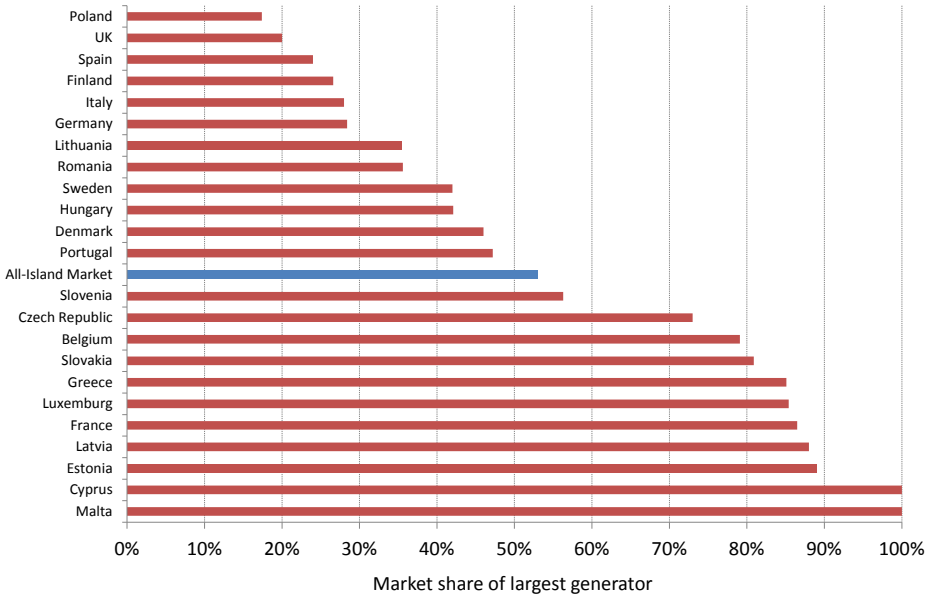
3.6.3 Although other producers have increased their market shares in recent years, ESB remains the largest player in the All-Island Market in terms of generation assets with a portfolio totalling around 4.5GW of installed capacity. AES now owns more than 1.5GW of oil-, coal- and gas-fired installed capacity. Since acquiring the former Endesa assets, SSE currently owns more than 1GW of oil-fired generation alongside more than 500MW of wind installed capacity. Other generators operating in the All-Island market include Bord Gáis, Viridian and Tynagh.

3.6.4 On the retail side, there are five major suppliers that account for over 95% of electricity sales on the island of Ireland. Those include Power NI (Viridian), Electric Ireland, (ESB), Airtricity (SSE), Bord Gáis and Energia (Viridian).

3.6.5 In considering the future HLD of the All-Island Market, it is useful to compare it to other European wholesale electricity markets on two different measures of concentration[14]:

- Share of output of the largest generating company (Figure 6); and
- Number of main electricity companies in the wholesale market (Figure 5).

Figure 5– Market share of the largest generator in European markets in 2011

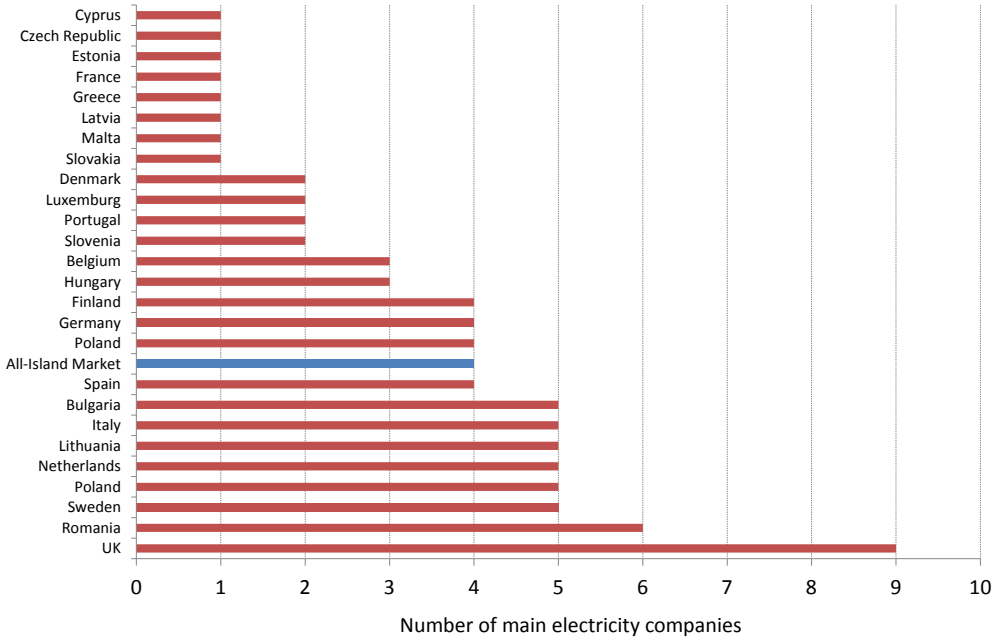


Source: Eurostat data[15] for all markets apart from the all island market; Analysis based on SEMO data for the all island market.

14 There are different indicators for market concentration with no single indicator widely accepted as the definitive metric for use when comparing different markets.

15 As Eurostat reports data on a Member State basis it does not provide GB only data. The UK data can however be considered representative of the GB market given the relative size of GB when compared to Northern Ireland.

Figure 6 – Number of main electricity companies in European markets in 2011



Source: Eurostat data[16] for all markets apart from the all island market; Analysis based on SEMO data for the all island market.

3.6.6 The degree and scope of market power can change over time, as a result of changes such as:

- build and closure of generation;
- increased physical interconnection, which increases the effective size of the market as well as opening the market for new cross-border participants;
- the move to day-ahead and intraday market coupling as part of compliance with the EU Target Model; and
- increased participation by the demand side in the electricity market.

3.6.7 The robust market power mitigation strategy could include elements of the existing market power mitigation strategy in place for the SEM, such as:

- implementation of Directed Contracts (DCs), which could also encourage the development of liquidity in the reference market for the DCs;
- bidding principles;
- market monitoring; and
- local market power controls.

16 As Eurostat reports data on a Member State basis it does not provide GB only data. The UK data can however be considered representative of the GB market given the relative size of GB when compared to Northern Ireland.

3.7 POLICY GOALS FOR RENEWABLE ENERGY

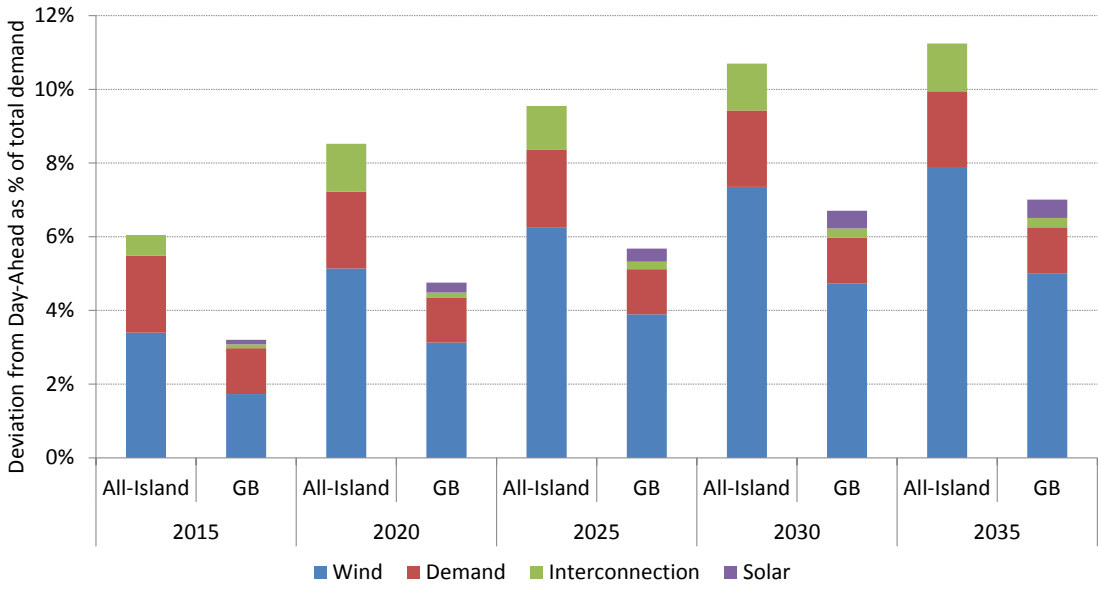
3.7.1 The island of Ireland has abundant wind resources. That in combination with the strong push at EU level for renewable energy has led to increased wind deployment in Ireland.

3.7.2 The 2020 target of 40% renewable generation is expected to be largely delivered by wind generation, and is the highest for any synchronous system in Europe[17]. The increased level of wind generation will pose challenges for market design and for system operation.

3.7.3 In terms of market design, higher wind penetration will increase the relative importance of adjustments in the intraday timeframe. This is because with growing levels of wind installed capacity on the system, wind is expected to become the main driver for deviations from the day-ahead forecast position.

3.7.4 Figure 7 illustrates how generation technologies may differ in the volume risk that may be associated with intraday markets. It shows the total annual deviation between day-ahead forecast and out-turn for wind, demand, solar and interconnector flows[18] as a percentage of total annual demand for both the All-Island Market and GB. The projections are taken from a recent study by Pöyry Management Consulting on the within-day impacts of growing levels of intermittent renewable generation in GB and the island of Ireland.

Figure 7 – Projected annual deviation between Day-Ahead forecast and out-turn



Source: Pöyry Management Consulting

[17] Most EU markets are part of synchronous continental systems. The exceptions are GB, Malta and Cyprus and the all island market.

[18] Deviation is defined as the absolute difference of outturn value and expected value at the Day-Ahead stage.

3.7.5 Managing the all island electricity system with much higher levels of wind penetration will raise a number of operational challenges as wind turbines are non-synchronous when connected to the system.

3.7.6 There is currently a limit of 50% on the instantaneous non-synchronous output in the all-island market. If wind penetration is above this limit, wind curtailment is carried out by the TSO to accommodate sufficient spinning reserve on the system to facilitate secure system operation.

3.7.7 The intention is to maintain curtailment of wind below 5% of the total available wind production, even as more wind capacity comes online. This will in part be delivered by an increase in the instantaneous non-synchronous generation limit to 75% by the implementation of new system services and operating procedures under the DS3 programme.

3.8 VISION FOR DEMAND SIDE MANAGEMENT

3.8.1 The Regulatory Authorities (RAs) in Ireland and in Northern Ireland have recognised the potential economic and environmental benefits of greater demand side management[19]. This could be facilitated by changes such as the roll-out of smart metering by 2020 in Ireland and Northern Ireland, new forms of electric demand, and aggregation of distributed generation and storage.

3.8.2 The benefits of greater demand side management could include; avoided investment in peaking plant, lower curtailment of wind, support for system services, and possible mitigation of market power (both on a system-wide basis and a local basis).

3.8.3 Demand side participation has been promoted in the all island market for a number of years. In particular EirGrid operated (on behalf of the CER) the Winter Peak Demand Reduction Scheme. This was designed to improve tight generation capacity margins over the evening peak by encouraging participants to reduce their consumption from during peak hours between November and February. The scheme delivered between 100MW and 150MW of demand reduction on an annual basis.

3.8.4 The WPDRS scheme has now been phased out to encourage demand side participation in the SEM itself, where an aggregated group of demand centres can register as a Demand Side Unit (DSU). At the beginning of 2014, 87 MW of capacity was registered with DSUs in the SEM, an increase of 46MW since 2012.

[19] 'Demand Side Vision for 2020. Decision Paper. SEM/11/022', 27 May 2011. SEM Committee'

4 TOPICS FOR THE HLD OF ENERGY TRADING ARRANGEMENTS

4.1 CONSULTATION QUESTIONS

4.1.1 The following consultation questions relate to the issues discussed in this section:

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

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

4.2 OVERVIEW

4.2.1 This document differentiates between different HLD options with respect to how energy is traded in and across different market timeframes[20]; namely:

- Forward (FW);
- Day-Ahead (DA);
- Intraday (ID);
- Energy Balancing;
- Imbalance or ex-post settlement.

4.2.2 This means that in all energy market arrangements, there will be a set of prices that will change for a particular trading period as we move closer to real-time (e.g. forward prices, DA price, ID prices, balancing prices, imbalance prices). This is different from today´s SEM where there is a single price for a particular trading period.

4.2.3 Table 1 is an overview of the prices in the various markets and its characteristics. Public reporting of prices in all markets will increase transparency of trading outcomes.

4.2.4 All of the HLD options assume balance responsibility for market participants, which is a key feature of the EU Target Model as described through the various Network Codes. Each market participant is responsible for its own volumes (directly or through a Balance Responsible Party, (BRP)).

[20] There are other possible ways of differentiating between energy trading arrangements. For example, they could be differentiated according to how constraints and ancillary services are treated within the results of the energy market. For example, co-optimising energy and reserves would be a different option to one where they are dealt with in separate markets or in separate ways. For the purposes of the revised SEM HLD, co-optimisation of energy and reserves has been ruled out as a possible option, and therefore we concentrate on differentiating between the options with respect to the trading within and across different timeframes (in line with the approach taken in the EU Target Model).

4.2.5 This means that if the market participant (or its chosen BRP) is out of balance after all market timeframes, it will face an ex-post charge (or payment) for those volumes. This imbalance payment or charge will reflect the marginal cost to the TSO of procuring energy supply or demand to match the sum of individual market participants' energy imbalances.

4.2.6 As a result, the earlier markets act as a tool for market participants to manage risks and their exposure to the ex-post or imbalance price. It is:

- the expectation of the ex-post or imbalance price(s) that drives prices in the ID market;
- the expectation of the ID market prices and ex post or imbalance price(s) that drives prices in the DA market; and
- the expectation of prices from the DA market that drives forward trading.

Table 1– Counterparties, Prices and Public Reporting in different marketplace

Marketplace	Counterparty	Prices	Public reporting
Bilateral (Physical/Financial)	Market participant	Contract specific	No
Bilateral/OTC (if applicable)	PX/Broker	Continuous prices per contract	Web site bulletin board of trade's on PX
Financial (future/forward/ CfD)	Power Exchange (PX)	Continuous prices from matched trades for all products incl. closing prices	Web site bulletin board + price feeds
Day-Ahead	PX	Daily, marginal price per settlement period per price area	Web site bulletin board + price feeds
IntraDay Continuous	PX	Continuous prices from matched trades	Web site bulletin board + price feeds
IntraDay Auction	PX	Periodic, marginal price per settlement period per price area (per auction)	Web site bulletin board + price feeds
Energy balancing	TSO Single buyer	Marginal price(s) per settlement period per price area	Web site bulletin board
Non-Energy balancing	TSO Single buyer	Pay-as-bid price(s)	Possibly as part of TSO regular reporting
Imbalances	TSO	Marginal imbalance price(s) based on the energy balancing actions	Web site bulletin board

4.2.7 This means that the markets in different timeframes should be designed in a coherent way to allow efficient arbitrage of trading between them – i.e. the overall HLD needs to ensure that the market in each timeframe is 'fit for purpose'.

4.2.8 The mechanism by which the TSO can procure energy for balancing supply and demand can take the form of an integrated process of scheduling and dispatch (as in the SEM today) covering all volumes, or a mechanism based around 'simple' bids for residual (or net) volumes (i.e. a separate 'balancing market').

4.2.9 All of the proposed options are designed to be capable of implementing the market design if a future zonal review will divide the all island market into more than one bidding zone. In addition, the market design shall be compliant with any future decision on a wider balancing and/or control area(s).

4.2.10 Table 1 below lists the main topics (and associated choices) for differentiating how energy is traded in and across different market timeframes.

Table 2 – Topics of the HLD options and choices under each topic

Topic		Sub-Topic	Choices
Participation in European markets for trading of energy in day-ahead (DA) and intraday (ID) timescales	**DA**	**Portfolio vs. unit bidding**	Portfolio bidding Gross portfolio bidding Unit bidding
		Mandatory vs. voluntary	Voluntary Mandatory
		Bid format	Simple Block Sophisticated
	ID	**Portfolio vs. unit bidding**	Portfolio bidding Gross portfolio bidding Unit bidding
		Exclusive vs. Non-exclusive	Exclusive Non-Exclusive
		Bid format	Simple Block Sophisticated
Process for reaching feasible dispatch position		**Starting point of dispatch**	DA (and ID) nominations IC schedule
		Bids to the TSO for balancing and dispatch	Complex bids Inc's and dec's
		Timing of bid submission	At DA and updated continuously At DA and updated at specific intervals
Imbalance/Pool settlement			Marginal imbalance price(s) based on separate balancing mechanism Ex-post unconstrained market schedule
Arrangements for long-term trading		**Internal**	Physical Financial
		Cross-border	PTRs FTRs

4.2.11 We now describe these topics and choices in more detail, in order to inform Sections 5 to 9, where we describe each HLD option by the choices taken for each of these topics.

4.3 PARTICIPATION IN THE EUROPEAN DAY AHEAD AND INTRADAY MARKETS

4.3.1 This topic covers the arrangements for trading energy between market participants in the DA and ID timeframes.

4.3.2 The DA Market (DAM) refers to the European DA market coupling arrangements, based around a common European Gate Closure (GC) expected to be at 1100 UTC on the previous day (D-1) for a trading day (D) running from 2300 to 2300 UTC.

4.3.3 Participation in the DAM is the only way at the DA stage for market participants to access cross-zonal capacity (and thereby the European markets) to match trades and thereby have access to the liquidity in European markets

4.3.4 The ID market (IDM) in this context means the European ID market coupling arrangements. It is assumed that participation in the IDM is the only way for market participants to access cross-zonal capacity and thereby have access to the liquidity in European markets at the ID stage.

4.3.5 However, it may not be the only way in which market participants can adjust their scheduled position (as represented in their nominations). For example, it is possible that they could adjust their position through bilateral trades struck directly with another market participant, or by making changes within their own portfolio.

4.3.6 Cross-border trades and subsequently flows are always determined by trading in the DAM and IDM for all HLD options for energy trading arrangements. In all options, the TSO may also take curative congestion management measures during these timeframes for operational security reasons. Finally, TSOs may take coordinated balancing actions that affect cross border flows post intraday gate closure.

4.3.7 There are two issues that are common for both market timeframes:

- the aggregation level of the bids to buy or sell energy that are submitted in the DA and ID markets ('portfolio vs. unit' bidding); and
- the bid format

4.3.8 In addition, we distinguish between mandatory and voluntary participation in the DAM; and exclusive and non-exclusive participation in the IDM.

PORTFOLIO VS. UNIT BIDDING (DAM and IDM)

4.3.9 This topic covers the aggregation level of the bids to buy or sell energy that are submitted in the DA and ID markets. The main alternatives are:

- Portfolio bidding;
- Gross portfolio bidding;
- Unit bidding.

4.3.10 All of these alternatives will be using the Euphemia-compliant bid types defined later in the document.

PORTFOLIO BIDDING

4.3.11 Under portfolio bidding arrangements, a market participant can send one bid for energy in a single bidding zone, covering both all of its production assets and any demand it is responsible for procuring on behalf of end-customers. For example a market participant with 100MW of demand and 120MW of generation assets could submit a net bid of 20MW into the DAM or IDM.

4.3.12 A market participant is free to divide its bids into smaller parcels if it wishes, including bids linked to specific generating units and/or demand. Portfolio bidding therefore provides greater flexibility to market participants in terms of the preferred bidding strategy.

4.3.13 This means that it enables some market participants to better optimise their own assets while accounting for more complex factors that may not be capable of being captured in the market bidding structure and the market algorithm. This would be of most benefit to portfolio players rather than small independent generators or suppliers (with no more than one generating unit).

4.3.14 In addition, portfolio bidding opens up the market for financial market players, which might stimulate liquidity in the market. There might also be more scope for aggregators who could create a larger portfolio. However, it is also possible to allow aggregation within a unit-based bidding regime (e.g. AGUs in the SEM), although there will be typically be limits on the scope of aggregation in those circumstances (e.g. total amount of aggregation allowed, or size of units that can be aggregated).

4.3.15 On the other hand, portfolio-based bids in the DAM and the IDM will not specify the details of generating units supporting these bids. This could reduce the transparency of the DAM and IDM to the TSO and/or market monitoring bodies at the time of bidding and provision of market results. It may also make ex-post market monitoring activities more complicated, depending on the granularity of the portfolio bids (e.g. in terms of price-quantity pairs).

4.3.16 In all of the options presented in this paper, it is assumed that market participants are required to provide unit-based physical nominations[21] for their generation to the TSO after they have received their schedule from the DAM (or IDM). For demand, this will still be at an aggregated (portfolio) level. The physical nominations are intended to provide the TSO with information (including location) on the expected production schedule, to help the TSO identify any possible resulting feasibility issues.

[21] The nomination process is where the market participant will, based on its portfolio schedule from the market, send the detailed unit based information to the TSO on how it plans to honour its schedule .

GROSS PORTFOLIO BIDDING

4.3.17 Gross portfolio bidding is normally applied to increase transparency for all volumes submitted to the market and can be seen as a mitigation measure for the lack of transparency for portfolio bids as well as a measure to increase the liquidity of the market.

4.3.18 Under gross portfolio bidding, a market participant is required to provide separate bids for generation and demand into the DAM or IDM. Therefore, this does not allow netting of generation and demand by market participants. Using the example from 4.3.11, a market participant with 100MW of demand and 120MW of generation assets would submit two separate bids of 100MW demand and 120MW generation into the DAM or IDM.

4.3.19 The advantage of Gross Portfolio bidding is that it should encourage more liquidity in the DAM and IDM, helping to develop liquidity 'along the curve' and providing an effective near time market for participants to balance their positions and avoid exposure to the imbalance prices[22].

UNIT BIDDING

4.3.20 Under unit bidding arrangements, a market participant has to submit a separate bid for each of its generating units that it wishes to participate in the market.

4.3.21 Unit bidding is not applicable to the buyers of electricity, as demand is always represented by a portfolio bid (covering demand only). Therefore, when any reference is made to unit bidding hereafter, this should be interpreted as applying to bids to sell energy only.

4.3.22 A market participant representing both generation and demand will therefore have to submit individual bids for each generating asset as well as a single bid for the demand they are procuring energy to meet.

4.3.23 Unit bidding allows for more sophisticated bid formats as well as revealing the location of each accepted generating unit at an earlier stage (as the market schedule is forwarded to the TSO at the same time as to the market participant) compared to a portfolio bid where the detailed location will follow as part of the nomination process. As such it provides greater transparency to the TSO and/or market monitoring bodies at the time of bidding and provision of market results to market participants.

[22] Ofgem's recent consultation (and responses to it) on 'Secure and Promote' measures to promote liquidity explored this issue ('Wholesale power market liquidity: statutory consultation on the 'Secure and Promote' licence condition', Ofgem. November 2013). Vertically integrated players in GB have entered into gross bidding agreements for 30% of volumes. Nord Pool also has gross bidding agreements which may go further to increasing transparency and liquidity.

4.3.24 Unit-based bidding may also make ex-post market monitoring easier for the Regulatory Authorities as they have specific unit-based bids to consider (rather than a set of price-quantity pairs for portfolio bids, which may or may not be able to be linked to specific units in ex-post market monitoring).

4.3.25 Unit bidding means that the optimisation across production assets in a portfolio is carried out by the central algorithm taking into account the bids received from all available generating units and demand. This restricts the ability of each market participant to optimise within its portfolio (to that extent it is unable to accurately reflect the commercial and technical operating characteristics of its plant within the permitted bids/offer structure).

4.3.26 Unit-based bidding may also be a barrier to financial market participants from participating in the market. The impact of unit-based bidding on the scope of aggregation will depend on the particular rules in place – for example, the current SEM market requires unit based bidding for the majority of generator units but allows for portfolio based bidding from aggregated generator units and demand side units.

4.3.27 To conclude, the choice of unit or portfolio bidding will depend on balancing the potential efficiency gains by allowing market participants the freedom to manage the trading of their own portfolio on an aggregate basis with the advantages of unit bidding in terms of earlier transparency of market data that is specific to generation units and easier market monitoring.

MANDATORY VS. VOLUNTARY (DAM)

4.3.28 Mandatory participation in the DAM means the following for different types of market participants:

- thermal generating units have to submit bids for their expected availability;
- Generation from Renewable Energy Sources (RES) have to submit bids based on forecasted output for intermittent RES and based on availability for controllable RES or with absolute priority dispatch submit an expected output; and
- demand has to submit bids for the forecasted demand level based on their own forecast.

4.3.29 The reason for making a market mandatory is normally to pool liquidity[23] in at least one market timeframe to deliver a robust and transparent reference price that can be easily accessed on equal terms by a wide range of market participants including independent suppliers and generators.

4.3.30 However, arguments can be made that making a market mandatory can limit the

[23] Liquidity is usually defined as the degree to which an asset can be bought or sold in the market without affecting the asset's price. Therefore, low liquidity can mean that the reference price from the market is less representative of the value of the underlying commodity

ability of some market participants to tailor their risk management strategy by choosing the preferred timeframes for energy trading adjusted to the individual market participants´ preferences.

4.3.31 If mandatory participation is combined with strong ex-ante regulation of bidding (e.g. in the form of SRMC bidding), then this further limits the ability of market participants to choose the desired market for trading. In the case where there are no bidding rules then market participants have the flexibility to submit bids that would place them out of merit or conversely to ensure that that are 'must run' through submitting zero or negative prices. This is an important part of a risk management strategy, but will also impact on overall market results.

4.3.32 The flipside of allowing market participants' choice over where to trade is possible uncertainty over which markets get the most liquidity and why. For example, low liquidity in voluntary centralised market places (such as the DAM or the IDM) can reduce the risk mitigation tools available for non-vertically integrated players (as discussed in the February 2013 Next Steps Decision Paper).

4.3.33 There are other ways of encouraging liquidity in particular markets rather than directly mandating participation. This includes:

- market maker obligations on participants;
- gross portfolio bidding;
- choice of reference price (e.g. DAM, ex post) in centralised Contract For Difference (CfD) arrangements. As an example in the All-Island Market, this could potentially apply to the Directed Contracts (assuming that they continue in some form).

EXCLUSIVE VS. NON-EXCLUSIVE (IDM)

4.3.34 This refers to whether the (organised) IDM is the only way for a market participant to be able to change their nominated position after the DAM and ahead of the final intraday gate closure. The IDM can be exclusive or non-exclusive.

4.3.35 Were the IDM to be non-exclusive, then market participants would then have the flexibility to balance their position within their own portfolio, or through bilateral trading with other market participants in the same bidding zone outside the continuous European market coupling arrangements.

4.3.36 On the other hand, if the centrally organised IDM is exclusive this is the only place where market participants can refine their position intraday.

4.3.37 Similar arguments regarding the compulsory nature of the market apply to the IDM as to the DAM. For example, liquidity is necessary for the IDM to allow market participants to adjust their positions from the DAM ahead of the balancing timeframe.

4.3.38 In any case, however, access to interconnector capacity and thereby the European markets in the DA and ID timeframes can be obtained only through the organised DAM and IDM. This in itself will attract liquidity to these organised markets, building on the liquidity provided by the interconnector capacity itself.

BID FORMAT (DAM)

4.3.39 The Price Coupling of Regions (PCR) algorithm, Euphemia, accepts a set of different bids with different degrees of complexity including simple, block and sophisticated bids.. However, it cannot currently accommodate complex three-part bid structures like those used in the current SEM market arrangements.

4.3.40 The alternative bid structures that are considered in the HLD options presented in this document are the following:

Simple bid: A simple price-quantity bid (i.e. 50MW for the price of 40€/MWh for a single market settlement period). One bid can consist of a set of these price-quantity pairs in a monotonously increasingly order to reflect the individual prices for the assets that form a portfolio.

Block bid: A bid that refers to more than one market settlement period, potentially with variable output over different periods and has to be accepted as a whole. Block bids can also be linked with a bid being considered conditionally if another bid (that it is linked to) is accepted.

Sophisticated bid[24]: A set of simple hourly bids belonging to a single market participant with additional complex conditions (which can be used separately or in combination) which typically apply over the optimisation period of the market algorithm (e.g. 24 hours in Euphemia). These additional complex conditions include the following:

- Minimum income condition (MIC)
  - The amount of money collected over the market settlement periods covered by the set of bids must cover production costs, which are defined by a fixed term (in €) and a variable term (in €/MWh). MIC orders are either activated or deactivated as a whole.
- Load gradient
  - The amount of energy matched in one period is limited by the amount of energy matched in the previous period. The load gradient condition is equivalent to a generating unit specifying a ramp rate.
- Scheduled stop
  - In the case where a market participant has submitted a MIC bid for a power plant that is not accepted, a Scheduled Stop bid allows for accepting a subset of the bids (e.g. up to 3 hours) to allow for a non-abrupt shut-down of the power plant.

[24] These refer to generating units rather than the demand side or a portfolio bid that could include more than one generating unit

Complex bids: Three part bids that include variable cost of generation, start-up costs, no-load costs as well as other technical characteristics (ramp rates etc.). Such bids are used in the current SEM but currently cannot be accommodated through the European coupling arrangements. Therefore, in the options presented in this document, they are only used where an all island pool arrangement is retained.

4.3.41 In general, market participants can submit different bids for different trading periods. This differs from the current SEM arrangements where a single price for each day is considered for all generation units (other than interconnector units). For example a generating unit can submit a bid of 50MW at a price of €50/MWh in one trading period and a bid for 50MW at a price of €70/MWh in the subsequent trading period.

4.3.42 Portfolio bidding can be accommodated though simple or block bids. Unit bidding into European coupling arrangements allows for the whole range of bids (simple, block and sophisticated).

4.3.43 Further information on the bidding structures catered for in the EU DA market can be found in the two information publications from SEMO[25].

BID FORMAT (IDM)

4.3.44 A periodic auction can allow a more sophisticated set of bids[26] than continuous trading, where only simple and block bids are allowed.

4.3.45 The current draft version of the Capacity Allocation & Congestion Management (CACM) Network Code (NC) states that intraday trading shall be continuous with congestion pricing. However, there are provisions for additional periodic auctions that have to complement continuous trading. All options presented in this paper can support both forms of trading (only continuous or continuous accompanied by periodic auctions).

4.3.46 If periodic auctions are to be implemented, this might allow for more sophisticated bids and the nomination process will be similar to the process in the DAM. In terms of practicality, given that the time for running an intraday auction would be limited in comparison to the DAM auction, the degree of sophistication of the bid might be reduced in intraday markets, even with periodic auctions.

[25] http://www.eirgrid.com/media/PCR_EUPHEMIA_CLARIFICATION.pdf
http://www.eirgrid.com/media/PCR_NWE_MO_TSO_Review.pdf

[26] This is a requirement in the Capacity Allocation and Congestion Management Network Code

4.4 PROCESS FOR REACHING FEASIBLE DISPATCH POSITION

4.4.1 This topic covers the interaction of the electricity market with the activities of the TSO, who is ultimately responsible for the safe and secure operation of the electricity system.

4.4.2 Under this topic we consider the starting point of the TSO's scheduling and dispatch activities and how market participants can provide commercial information to support the TSO in ensuring a balance between supply and demand and a stable frequency.

STARTING POINT OF DISPATCH

4.4.3 In all the HLD options, the TSO is ultimately responsible for the safe and secure operation of the network (including respecting conditions such as absolute priority dispatch where it exists). This may require the TSO to take actions in parallel with the operation of the traded energy markets (e.g. forward, DAM, IDM).

4.4.4 There are two broad choices for the starting point that the TSO can use for reaching a feasible dispatch position. In either case, the TSO will respect the 'absolute' interpretation of priority dispatch that applies in the All-Island Market whereby 'economic factors are taken into account only in exceptional situations'.

4.4.5 The first approach is that the TSO's starting point for dispatch is the nominations provided by market participants based on settled trades (including the physical trading in the FW timeframe as well as trades from DAM and IDM). In this case, the TSO's objective is to reach feasible dispatch by minimising the cost of deviation from the market participants' nominations based on bids (incremental and decremental) into a balancing mechanism for residual volumes.

4.4.6 A key aspect of this is the time at which the TSO receives the information from market participants that it can use to test that a feasible dispatch is possible. The detailed design phase will need to specify the format and rules for these nominations, including the granularity (i.e. minute by minute, half hour by half hour).

4.4.7 In this approach, market participants provide initial nominations to the TSO after the DA market (reflecting all trades in the FW and DA timeframes), and update nominations at various points during the ID timeframe. There are different ways in which the TSO can act on the updated nominations – e.g. on a continuous basis or periodically.

4.4.8 Despite receiving physical nominations from market participants, the TSO is likely to still use a central demand and wind forecast to try to identify any potential system-wide imbalances not reflected in the market participants' nominations. This means that even though the TSO tries to respect nominated positions, it has the means and is in a position to take actions to ensure system security and stability.

4.4.9 The second approach is that the TSO issues dispatch instructions to minimise overall production cost based on commercial and technical data submitted by the market participants into a pool-based scheduling and dispatch process at fixed points during D-1 and D.

4.4.10 Even in this case the flows across the interconnectors arising from the DA and ID markets have to be respected. An important question for this approach is how the pool-based scheduling process affects the incentives on market participants to trade in the pan-European markets (e.g. DAM and IDM) outside the pool.

BIDS TO THE TSO FOR BALANCING AND DISPATCH

4.4.11 In all the HLD options, all participants in the balancing or pool mechanisms have to submit detailed technical information to the TSO to help it operate the system safely and securely.

4.4.12 The main differentiating factor is the form of the commercial information with two alternatives available:

- Complex bids for use in an Integrated Scheduling Process designed to produce unit commitment. An additional economic dispatch tool may need to be used for energy balancing closer to real time.
- Simple incremental and decremental bids (incs and decs) for use in a separate Balancing Mechanism that produces an economic merit order. These bids (both price and volume) can differ within individual trading periods.

The Integrated Scheduling Process[27] is defined in the Electricity Balancing Network Code as follows: "Integrated Scheduling Process means a market-based continual process performed by a Transmission System Operator operating a Central Dispatch System in order to ensure secure system operation in real time. It starts in day-ahead timeframe and last until real-time. It is implemented as an optimisation problem where Balancing, congestion management and Balancing Capacity procurement are performed simultaneously based on bids as well as technical parameters provided by Market Participants. Integrated Scheduling Process determines the Unit Commitment of the majority of system resources capacity. The objective function for the Integrated Scheduling Process is minimisation of energy delivery cost while complying with operational security requirements."

4.4.13 Typically, in an Integrated Scheduling Process, complex bids are used to try to better reflect the cost structure of the generating units. In the separate Balancing Mechanism simple incs and decs are the commercial information provided by market participants to the TSO.

[27] More details on the Integrated Scheduling Process can be found in the Supporting Document for the Network Code on Electricity Balancing: www.entsoe.eu/major-projects/network-code-development/electricity-balancing/

4.4.14 In both cases however all commercial data would relate to individual units. In the case where the bids are simple price/quantity incs and decs, the TSO still have the technical characteristics of each individual unit as submitted by the unit operator.

4.4.15 The working assumption in either case is that marginal price(s) (i.e. pay as cleared) will be used to settle bids activated by the TSO for the purpose of balancing energy. In the pool, these marginal prices will simply be the ex-post SMPs.

4.4.16 In the case where a separate Balancing Mechanism is in place, the TSO will need to calculate marginal prices for the activation of balancing energy. Where the TSO also uses the bids in the balancing mechanism to resolve non-energy balancing issues, then it will need to put in place mechanisms to isolate the costs of energy balancing actions.

4.4.17 For example, this could be done through the 'flagging and tagging' of non-energy balancing actions so that they are not included in the calculation of the marginal balancing energy prices, or through the calculation of an ex-post unconstrained schedule for the balancing bids only. This tagging process is carried out in other European markets. Another option would be to have separate markets for re-dispatch (i.e. for non-energy balancing actions) and for energy balancing.

4.4.18 Where bids for energy balancing are used by the TSO for non-energy balancing purposes (e.g. to relieve a network constraint), the assumption is that these would be settled on a pay-as-bid process (in the same way as deviations from the schedule are paid in the SEM today).

4.5 IMBALANCE

4.5.1 Ultimately, market participants will pay or receive an ex-post price for all volumes neither settled in ex-ante markets (e.g. ID, DA and FW), nor activated by the TSO. This means that the nature of the ex-post arrangements is very important and will affect the incentive for market participants to trade volumes in earlier markets. Given that the ex-post (or imbalance) market is in essence the market of last resort, its structure is fundamental to the design of the overall electricity trading arrangements.

4.5.2 The ex-post prices could be determined through the operation of pool arrangements (which inform the schedule and dispatch) or by the marginal cost of pure energy balancing actions taken by the TSO in a specific energy Balancing Mechanism (either alongside or after the intraday market).

4.5.3 In both alternatives, the TSO can take actions to establish a feasible dispatch. These can be a combination of energy balancing actions as well as non-energy actions. The TSO can use the same bids for both, but the pricing of these will be different. In addition to the bids from market participants to the ex-post pool or the balancing mechanism, the TSO may have other available assets procured through ancillary service contracts.

4.5.4 In the current market arrangements, absolute priority dispatch is facilitated in the market schedule by allowing generators to register as price takers which are scheduled ahead of all price makers in the ex-post market schedule. All four options for energy trading arrangements options presented in this paper are intended to facilitate absolute priority dispatch through requiring the TSO to accommodate output from generating units with priority dispatch in non-exceptional circumstances. The generating units with absolute priority dispatch can then act as price takers in the imbalance settlement process or the ex-post pool arrangements (depending on what ex-post pricing arrangements are in place in the particular option).

POOL ARRANGEMENTS

4.5.5 Typically, an ex-post pool will calculate (marginal) ex-post (or imbalance) prices through an unconstrained market schedule based on complex bids submitted by market participants (as in the SEM today). The ex-post price calculations will need to include an element to allow market participants to recover start-up and no-load-costs, which could be for example the uplift mechanism used in the SEM today or alternatively more targeted make-whole payments.

SEPARATE BALANCING MECHANISM

4.5.6 In calculating the imbalance price, the TSO will need to put in place mechanisms to isolate the costs of energy balancing actions as set out in Section 4.4.18. The marginal price(s) from this Balancing Mechanism will be used to determine the imbalance price(s). Either a single price or a dual price system can be used for imbalance prices.

4.5.7 The single-price system creates a single imbalance price for the relevant trading period based on the bids for upward and downward regulation in the balancing mechanism. This means that market participants receive (or pay) the same price for imbalances whether short or long (having a negative or positive imbalance).

4.5.8 One example of a dual pricing regime is that if a BRP is short when the system is long, it is settled at the appropriate DAM price. If a BRP is short when the system is short, it is settled at the upward regulation price. On the other hand, if a BRP is long when the system is short, it is settled at the appropriate DAM price. If a BRP is long when the system is long, it is settled at the downward regulation price from the balancing market.

4.5.9 In this example, imbalance volumes supporting the system are settled at the appropriate DAM price, whereas imbalance volumes that do not support the system are settled at the balancing market price.

4.6 ARRANGEMENTS FOR LONG-TERM TRADING

4.6.1 This topic covers the arrangements for trading in the forward timeframe (before the

DA stage) and can be considered separately from the trading of energy within a bidding zone (internal), and between bidding zones (which requires access to cross-zonal capacity).

INTERNAL

4.6.2 Forward trading can be physical or financial. Physical forward trading means trading of physical contracts for delivery and consumption of electricity ahead of the DAM. Trading can be exchange-based, carried out via a broker or purely a bilateral trade directly between market participants.

4.6.3 If exchange-based, then all financial settlements are carried out by a central Clearing House. The market participants have to nominate their volumes from the physical forward trading as part of the DA nominations to the TSO.

4.6.4 All four HLD options presented in this paper would allow the establishment of a financial market. Financial forward trading means trading of financial products ahead of the DAM. The main purpose of such any forward market is to give market participants the opportunity to have a long-term hedge against price risk in the short-term physical markets (e.g. DAM, IDM or ex-post). The reference price for the contract is therefore taken from the relevant short-term physical market.

4.6.5 The Financial market and the Physical underlying market (in most cases the DAM) are dependent on each other to support liquidity.

4.6.6 To have a liquid financial market, the robustness and liquidity of the reference price is important, and one of the key aspects to this is to have high share of the underlying volumes to be priced as part of this. Without a robust and reliable reference price the development of financial markets will be much more difficult.

4.6.7 At the same time, for a market participant to put most of its volumes in a (voluntary) short-term market (day-ahead), it needs a liquid tool to hedge its price risk (although the forward market does not necessarily protect against volume risk as it doesn't lock in physical volumes).

4.6.8 The financial market can have forward, futures, options and CfD products for long term risk hedging, with the particular nature of these products being driven by the preferences of market participants.

4.6.9 Typically the products will be yearly (multiple years), quarterly, monthly, weekly and potentially even down to daily. Each of these products will have their individual trading and delivery periods and it should also involve cascading between timeframes (open contracts in yearly contracts are automatically transferred to 4 quarterly products after closure of the yearly contract and so on).

4.6.10 A centralised financial market will require centralised Clearing House arrangements

that will manage settlement, invoicing and collaterals. The market participants will receive separate settlement statements and invoices from the Clearing House thus this will not be part of any energy market settlement. This will not affect any nominations or processes in the energy markets.

4.6.11 Another solution is where financial trading is carried out through brokers. Tullett Prebon provides such services for CfDs in the current SEM.

CROSS-BORDER

4.6.12 The existence of long-term cross-border risk hedging tools is a central feature of the EU Target Model. These tools can be in the form of explicit physical access to cross-zonal capacity before the DAM (where all physical capacity is allocated implicitly), or financial products.

4.6.13 Physical explicit rights can be provided through a Physical Transmission Right (PTR) allocated through auctions organised by the owner of the cross-zonal capacity. A PTR gives the holder the right to physically nominate a flow on the interconnector before the DA stage.

4.6.14 Under the EU Target Model, 'Use it or sell it' (UIOSI) provisions are applied to PTRs at the DA stage. This means that if a flow has not been nominated by the DA stage, the capacity is made available for implicit allocation through the DAM (and then into the IDM if unsold in the DAM). The PTR holder receives the implicit value of the capacity in the DAM (down to a minimum value of zero) i.e. this value is the price difference between the two zones connected by the cross-zonal capacity covered by the PTR (in the direction of flow allowed by the PTR).

4.6.15 PTRs allow market participants to directly hedge the price and volume risk associated with forward cross-border energy trades. However, PTRs can reduce the amount of physical cross-zonal capacity available for implicit allocation in the DAM (and then the IDM), which may reduce the effective liquidity of the DAM.

4.6.16 Financial products can take two forms – a Financial Transmission Right (FTR), which is sold only by the cross-zonal capacity owner as in the case of PTRs (and hence is backed up by the congestion rents received through market coupling), or a CfD, which can be sold by any party. In the options, where we have assumed that only financial cross-border products are available, we have assumed that they are FTRs.

4.6.17 An FTR does not give the holder a right to physically nominate a flow at the DA stage. Instead they receive the price differential between the two zones for which they hold cross-zonal capacity. FTRs can either be options (in which case the payment to the FTR holder is never less than zero) or they can be obligations (whereby the FTR holder has to make a payment if the price differential is in the opposite direction to their capacity holding).

4.6.18 FTRs allow market participants to directly hedge the price risk associated with forward cross-border energy trades, without reducing the amount of physical capacity available to be used in market coupling. However, as with financial forward energy contracts, they rely on liquid DAMs being in place in order to allow the FTR holder to manage its volume risk (i.e. whether or not it will get scheduled). The type of cross border transmission products (FTRs or PTRs) thus depends largely on the liquidity (and hence the compulsory nature) of the DAM.

5 SUMMARY OF OPTIONS FOR ENERGY TRADING ARRANGEMENTS

5.1 PHILOSOPHY OF THE OPTIONS FOR ENERGY TRADING ARRANGEMENTS

5.1.1 This document presents four options for the HLD of energy trading arrangements that have been developed to fit with the characteristics of the All-Island Market (as described in Section 3):

- Adapted Decentralised Market
- Mandatory ex-post Pool for Net Volumes
- Mandatory Centralised Market
- Gross Pool – Net Settlement Market

5.1.2 Table 3 and Table 4 describe how each option addresses the design topics discussed in Section 4.

5.1.3 Table 3 has been colour-coded to illustrates the difference in the 'philosophies' underpinning the options. It visually describes how the options range from market arrangements where market participants have both greater responsibilities and risk mitigation opportunities (coloured in blue), to ones in which there is much greater central control of market participants' activities (coloured in orange).

5.1.4 Table 4 spells out in more detail how each option is built up through the choices for each topic (and uses the same colour-coding as Table 3).

5.1.5 The Adapted Decentralised Market is characterised by an emphasis on allowing market participants greater choice over the markets and timeframes in which they trade energy in order to manage risk. This translates into this option being coloured in blue (denoting more liberalised and decentralised arrangements) across all topics in Table 3.

5.1.6 This option relies on market participants carrying out the majority of the required balancing through the various ex-ante markets while the TSO assumes a residual balancing role. It also creates an opportunity for portfolio bidding allowing market participants to optimise their portfolios based on all their internal parameters. However, it remains possible for generating units to submit unit-based sophisticated bids into the DAM (and potentially IDM).

5.1.7 The Mandatory ex-post Pool for Net Volumes is characterised by some choice for market participants around their trading in the DA and ID timeframes, but ultimately relies on a centralised approach to the determination of dispatch and ex-post prices and volumes (e.g. through complex bidding for increases or decreases in production into an integrated scheduling and dispatch process to help the TSO reach a least-cost dispatch for deviation from the nominated positions of market participants).

5.1.8 The result is this option being coloured blue for DA and ID markets but orange for the actions taken by the TSO and ex-post pricing and scheduling arrangements in Table 3, denoting the more centralised arrangements.

5.1.9 The Mandatory Centralised Market emphasises the importance of the DAM as the main market for physical trading of energy between market participants, with the IDM then the exclusive route for making adjustments to nominated positions intraday. Mandating participation in the DAM and making the IDM an exclusive market should ensure liquidity in those specific markets. Unit based bidding is intended to enhance transparency in the markets. This also allows for sophisticated bids in the DA (and potentially ID) timeframes that will allow market participants to use a more complex bidding structure than with portfolio bidding. The balancing arrangements revert to a relatively simple 'inc' and 'dec' bid structure.

5.1.10 This translates into orange colouring in the topics covering the DA and ID energy trading arrangements, and blue shades dominating in the topics covering TSO actions and imbalance arrangements in Table 2.

5.1.11 The Gross Pool – Net Settlement Market is characterised by a centralised approach to the determination of dispatch and ex-post prices and volumes (e.g. through complex bidding into an integrated scheduling and dispatch process to help the TSO reach a least-cost dispatch). It is open for market participants to carry out voluntary financial trading in the FW, DA and ID timeframes. The trading in the DAM and IDM determine the physical interconnector flow. This option retains an ex-post gross mandatory pool with complex bidding for all internal physical energy market arrangement within SEM.

5.1.12 This results in this option being coloured blue for day-ahead and intraday markets but dark orange for the actions taken by the TSO and ex-post pricing and scheduling arrangements in Table 3.

Table 3 – 'Philosophy' of options

			Adapted Decentralised Market	Mandatory ex-post Pool for Net Volumes	Mandatory Centralised Market	Gross Pool - Net Settlement Market
Participation in European markets for trading of energy in DA and ID timescales	DA	Portfolio vs. unit bidding				
		Mandatory vs. voluntary				
		Bid format				
	ID	Portfolio vs. unit bidding				
		Exclusive vs. Non-exclusive				
		Bid format				
Process for reaching feasible dispatch position		Starting point of dispatch				
		Bids to the TSO for balancing and dispatch				
		Timing of bid submission				
Imbalance/Pool settlement						
Arrangements for long-term trading		Internal				
		Cross-border				

Table 4 – Overview of options

			Adapted Decentralised Market	Mandatory ex-post Pool for Net Volumes	Mandatory Centralised Market	Gross Pool - Net Settlement Market
Participation in European markets for trading of energy in DA and ID timescales	DA	Portfolio vs. unit bidding	Gross portfolio bidding	Portfolio bidding	Unit bidding	Portfolio bidding
		Mandatory vs. voluntary	Voluntary participation [plus specific liquidity promoting measures]	Voluntary participation [with volume limitation measures]	Mandatory participation	Voluntary participation
		Bid format	Simple, block (or sophisticated unit) bids	Simple, block (or sophisticated unit) bids	Simple, block or sophisticated bids	Simple, block (or sophisticated unit) bids
	ID	Portfolio vs. unit bidding	Gross portfolio bidding	Unit bidding	Unit bidding	Unit bidding
		Exclusive vs. Non-exclusive	Non-exclusive	Non-exclusive [with same volume limitation measures]	Exclusive	Non-exclusive
		Bid format	Simple, block [or sophisticated] bids	Simple, block [or sophisticated] bids	Simple, block [or sophisticated] bids	Simple, block [or sophisticated] bids
Process for reaching feasible dispatch position		Starting point of dispatch	- DA nomination is the starting point (updated in the IDM) - Maintaining absolute priority dispatch	- DA nomination is the starting point (updated in the IDM) - Maintaining absolute priority dispatch	- DA nomination is the starting point (updated in the IDM) - Maintaining absolute priority dispatch	- IC volumes determined by DAM and IDM - Maintaining absolute priority dispatch
		Bids to the TSO for balancing and dispatch	Voluntary Inc's and dec's up to IDM GC (mandatory Inc's and dec's for generating units after IDM GC)	Mandatory net (+/-) complex bids for generating units	Mandatory Inc's and dec's for generating units	Mandatory complex bids for generating units
		Timing of bid submission	At DA and then updated continuously	At DA and then updated continuously	At DA and then updated continuously	At DA and then updated at specific windows
Imbalance/Pool settlement			Marginal imbalance price applied to all market participants based on (+/-) energy balancing actions	Net ex-post unconstrained market schedule to minimise production cost that determines the ex-post prices paid to/by all market participants (prices may vary by direction)	Marginal imbalance price applied to all market participants based on (+/-) energy balancing actions	Full ex-post unconstrained market schedule to minimise production cost that results in a single marginal price paid for all scheduled volumes
Arrangements for long-term trading		Internal	Both physical and financial trading	Both physical [with volume limitation measures] and financial trading	Financial trading	Financial trading
		Cross-border	PTRs to support bids for interconnector capacity	PTRs to support bids for interconnector capacity	FTRs to support bids for interconnector capacity	FTRs to support bids for interconnector capacity

5.2 ASSESSMENT CRITERIA FOR THE OPTIONS FOR ENERGY TRADING ARRANGEMENTS

5.2.1 In Sections 6-9 we describe an option in detail and then qualitatively assess it against the nine HLD criteria for the SEM (as listed in Section 1.2.4).

5.2.2 At this stage, we do not describe any option as having a particular strength or weakness against three of the SEM HLD criteria:

- **Security of supply:** the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.
- **Efficiency:** market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.
- **Adaptive:** The governance arrangements should provide an appropriate basis for the development and modification of the arrangements in a straightforward and cost effective manner.

5.2.3 We will continue to gather further evidence in these areas and therefore, we particularly seek views and evidence from stakeholders with respect to performance of the options against these criteria.

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

Security of supply: the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.

5.2.4 In our discussions so far with the TSO, they have indicated that they would be able to operate the system safely and securely under any of the proposed energy trading arrangements (including for example, market participants being able to re-nominate a physical position up to one hour before real-time).

5.2.5 This is on the assumption that the TSO would have the information and tools available to manage the system (e.g. managing step changes in output during or between settlement periods) that would need to be defined in the implementation stage. The impact of the use of such tools to deliver a feasible dispatch would have a greater impact on the performance of an option against other HLD criteria, such as the degree of equity delivered by a set of trading arrangements (i.e. how are production costs allocated to consumers?), rather than directly on the delivery of 'different' security of supply outcomes.

5.2.6 As noted in SEM-12-004[28], capacity adequacy can be encouraged in the longer-term with the addition of a CRM to any set of energy trading arrangements, as is being seen in the proposal of CRMs in European electricity markets with more decentralised trading arrangements, such as France, Germany, and Great Britain.

[28] 'Proposals for Implementation of the EU Target Model for the Single Electricity Market. Consultation Paper' SEM Committee, 24 January 2012/

5.2.7 This means that the assessment of performance with respect to long-term security of supply (i.e. sufficient capacity adequacy to facilitate the secure operation of the system) will primarily be determined by the decision on the need and design of any explicit CRM, rather than necessarily the design of this set of energy trading arrangements.

5.2.8 At this stage, we believe that any of the proposed energy trading arrangements could in theory work with any of the possible approaches to CRMs outlined in this document. In all of the options, the TSO's dispatch planning processes will also be informed by its own information and forecasting, as well as the information provided by market participants. For example, in North West Europe (NWE) markets, the TSO will typically use its own central forecasts for demand and variable renewable generation, such as wind, in combination with physical nominations for other production units to assess whether there is a need for it to take any intervention on energy balancing or non-energy balancing grounds.

5.2.9 The case and form for any intervention will be determined for example by the forecast horizon, the tools available to market participants to change the operation, and the lead-time for market participants to respond to any instructions.

5.2.10 One concern that has been raised with respect to safe and secure system operation under the revised HLD is the possibility of large swings in the scheduled interconnector flows close to real-time. This is an issue for all of the energy trading arrangements proposed in this paper as it reflects the requirement for the implicit allocation of cross-zonal capacity (i.e. allocation of capacity and flows together) through European market coupling processes in the day-ahead and intraday timeframes.

Efficiency: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.

5.2.11 In the consideration of the possible changes to the HLD in the SEM, there has been extensive discussion of the relative merits of different types of dispatch arrangements – see for example:

- the February 2013 Next Steps Decision Paper;
- the November 2012 report by the TSO on the Dispatch Model for the All Island Market/Transmission System;
- the September 2012 report by Easter Bay Consulting; and
- the January 2012 consultation on Proposals for the Implementation of the EU Target Model.

5.2.12 These discussions have noted that in theory an efficient dispatch outcome should be achievable under different dispatch arrangements, including central or self-dispatch[29].

[29] See page 26 of the September 2012 Easter Bay Report.

5.2.13 The January 2012 document stated that two conditions for a centralised market finding the most efficient commitment and dispatch of generator units:

- the SO having accurate information on the commercial and technical characteristics of the generator units; and
- the accuracy of the centralised algorithm used to produce the dispatch schedule, e.g. in the presence of non-convexities and linear constraints.

5.2.14 A self-dispatch market is seen as avoiding the possible incentive compatibility problem of a central dispatch market because generators internalise these operating constraints. However, there may be coordination issues within a self-dispatch system

5.2.15 The consideration of non-energy factors (e.g. reserve or locational issues) in the dispatch position produced by the initial nominations from market participants will depend on the arrangements in place for the procurement of these services (e.g. any contracts struck with the TSO before the day-ahead stage etc.).

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

5.2.16 The governance arrangements for any set of trading arrangements tend to be determined at the implementation stage, i.e. a level of detail below the HLD. Therefore, adaptability is typically not a major distinguishing feature of different energy trading arrangements.

6 OPTION 1: ADAPTED DECENTRALISED MARKET

6.1 CONSULTATION QUESTIONS FOR ADAPTED DECENTRALISED MARKET

6.1.1 The following consultation questions relate to the issues discussed in this section:

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

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

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

6.2 OVERVIEW OF ADAPTED DECENTRALISED MARKET

6.2.1 Of all the options, this one provides market participants with greatest choice over the markets and timeframes in which they trade energy in order to manage risk. This includes a choice over how they adjust their position intraday, as the IDM is not the only route for changing intraday nominations. If market participants have an effective choice between which markets to trade, then this can help to constrain the exercise of market power.

6.2.2 Increased trading opportunities for a market participant come with a greater responsibility for following its nominated position. This has the impact of integrating wind more fully into the market, as the same time as it becomes an even bigger part of the market as progress is made towards the 2020 markets.

6.2.3 One of the main issues for this type of market arrangements is the markets and timeframes where the most liquid trading happens. Therefore, this option contains specific measures in place to encourage liquidity in the DAM (and IDM) as key trading forums under the EU Target Model. These include market maker obligations on some or all participants and gross portfolio bidding, which should also help to constrain any concerns over market power.

6.2.4 A strong DA market may help to encourage greater demand side participation in the All-Island Market by providing a good ex-ante signal for when demand response is most valuable. All forward, DA and ID trading is portfolio-based, although market participants have the discretion to submit unit bids into the DAM and IDM. This means that market participants have more freedom for optimising within their own portfolio of production assets (compared to all of the other options).

6.2.5 Portfolio bids allow market participants to take account of information about commercial and technical characteristics where it is not possible to capture in the bid formats and structure that may be allowed in a centralised scheduling and dispatch algorithm.

6.2.6 This means that market participants with thermal generation in their portfolio have more control over the management of start-up and part-loading, which is an important activity for thermal plant in the All-Island Market. Obviously, such advantages would not accrue to non-portfolio participants.

6.2.7 The procurement of system services to manage non-energy factors affecting system security would primarily be carried out under the DS3 framework, but could also use bids from the Balancing Mechanism.

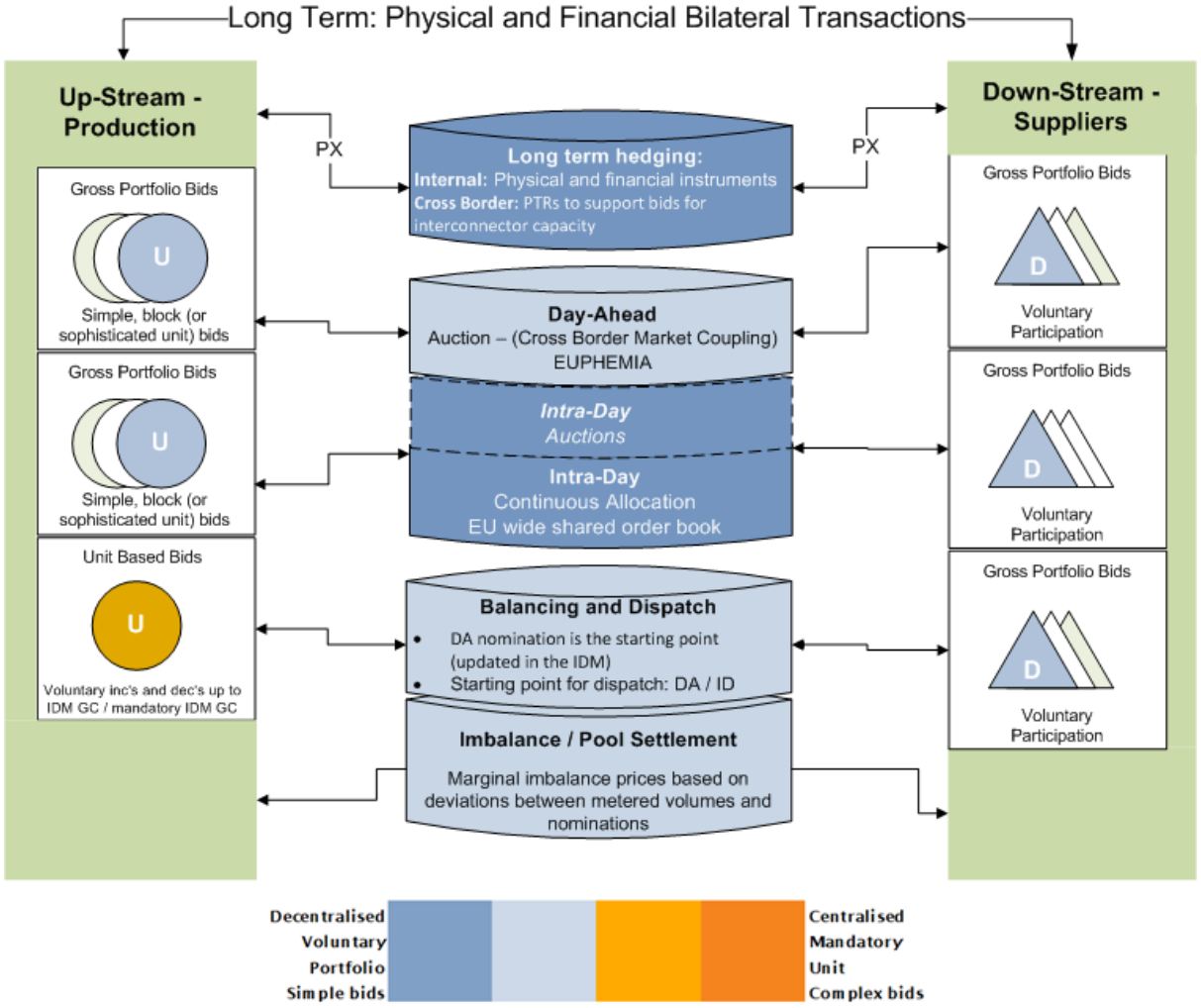
6.2.8 The extent to which 'reactive' intervention is needed by the TSO in this option to maintain security of supply will depend on the effectiveness of the incentives placed on market participants with respect to the provision of energy and non-energy services.

6.2.9 The latter is of particular importance to the SEM where there is already a large difference between the ex-post unconstrained energy schedule, and actual dispatch. This will be largely influenced by the nature of the arrangements put in place under DS3, including their interaction with the energy trading arrangements (including the Balancing Mechanism).

6.2.10 This option is closest to the design of electricity markets in the NWE region, which are built on the concept of a liquid DAM. It does not retain most of the current systems implemented for SEM and will therefore present a change for both central stakeholders like SEMO and the TSOs as well as market participants

6.2.11 A simplified illustration of this option is presented in Figure 8.

Figure 8 – Overview of Adapted Decentralised Market



6.3 DESCRIPTION OF ADAPTED DECENTRALISED MARKET

6.3.1 We now describe how this option operates from the forward timescales onwards.

6.3.2 In the forward timeframe, market participants can trade both physical energy and financial products through an intermediate agent (e.g., a broker or a power exchange), or directly with another market participants. A financial derivatives market (futures and forwards) allows for price hedging whilst mitigating the risk of market participants not trading physical volumes in the DAM and not promoting liquidity in the short-term physical markets.

6.3.3 Physical Transmission Rights (PTRs) with UIOSI provisions at the DA Stage are in place to support physical long-term cross-border trading.

6.3.4 All bids into the DAM are submitted to the Nominated Electricity Market Operator (NEMO) (the market operator under the European market coupling arrangements). The NEMO in its turn transfers exactly the same bid (in an anonymised form) to the PCR algorithm (Euphemia). This returns the DAM price (as a firm ex-ante price), and

the volumes and interconnector flows to be settled at that price. The results are provided to market participants on a portfolio basis where portfolio bids were submitted, and a unit basis where unit bids were submitted.

6.3.5 Market participants in their turn nominate the units and the corresponding output level of each one that will be used for respecting their individual DAM (portfolio) schedule as well as the results of any physical forward trading to the TSO. This would be done by the early evening/afternoon of D-1 (for a trading day starting at 23.00 UTC). Nominated volumes (traded up to and including DAM) are the starting point of the dispatch process.

6.3.6 The TSO is responsible for ensuring a feasible dispatch schedule (based on minimising costs of deviating from the nominated position). It takes relevant actions and issues dispatch instructions for ensuring system security whilst respecting absolute priority dispatch (as defined in SEM-11-062). The TSO can take balancing actions or even re-commit plants upon receiving DA nominations from market participants. There may be instances where the TSO need to take actions before nominations are received given the start-up times of some plants.

6.3.7 Market participants are responsible for updating their nominated positions to the TSO to reflect changes intraday, which could result from inter alia:

- Matching of bids in the European IDM;
- Rebalancing within their own portfolio (e.g. to balance change in plant availability or updated wind and/or demand forecast);
- Bilateral trading with other market participant within SEM (i.e., outside of the continuous matching algorithm).

6.3.8 ID trading through the European market coupling arrangements is done on a continuous basis, although periodic intraday auctions could be accommodated. Market participants can start trading in the IDM upon nominating DAM volumes. When trading continuously market participants submit simple unit bids to the IDM or whatever bids can be accommodated by the European market arrangements.

6.3.9 If periodic auctions are to be implemented, this might allow for more sophisticated bids and the nomination process will be similar to the nomination process at the DA stage.

6.3.10 Depending on the ID nominations and as other information becomes available (plant availability, updated intermittent generation forecast, demand forecast etc.), the TSO can, if required, issue updated dispatch instructions (even before the ID gate closure).

6.3.11 These dispatch instructions can use the bids submitted by market participants (both generation and demand) into the separate balancing mechanism operated by the TSO. These bids can be submitted at any time after the DA stage and be updated up to the ID GC. In some markets the TSO can have longer term bilateral contracts in

place with balancing service providers. This separate balancing mechanism will need to accommodate at least one of the Standard Products defined for the activation of balancing energy at a European level. This balancing mechanism is one of the tools that the TSO has to ensure secure system operation as well as energy balance at all times.

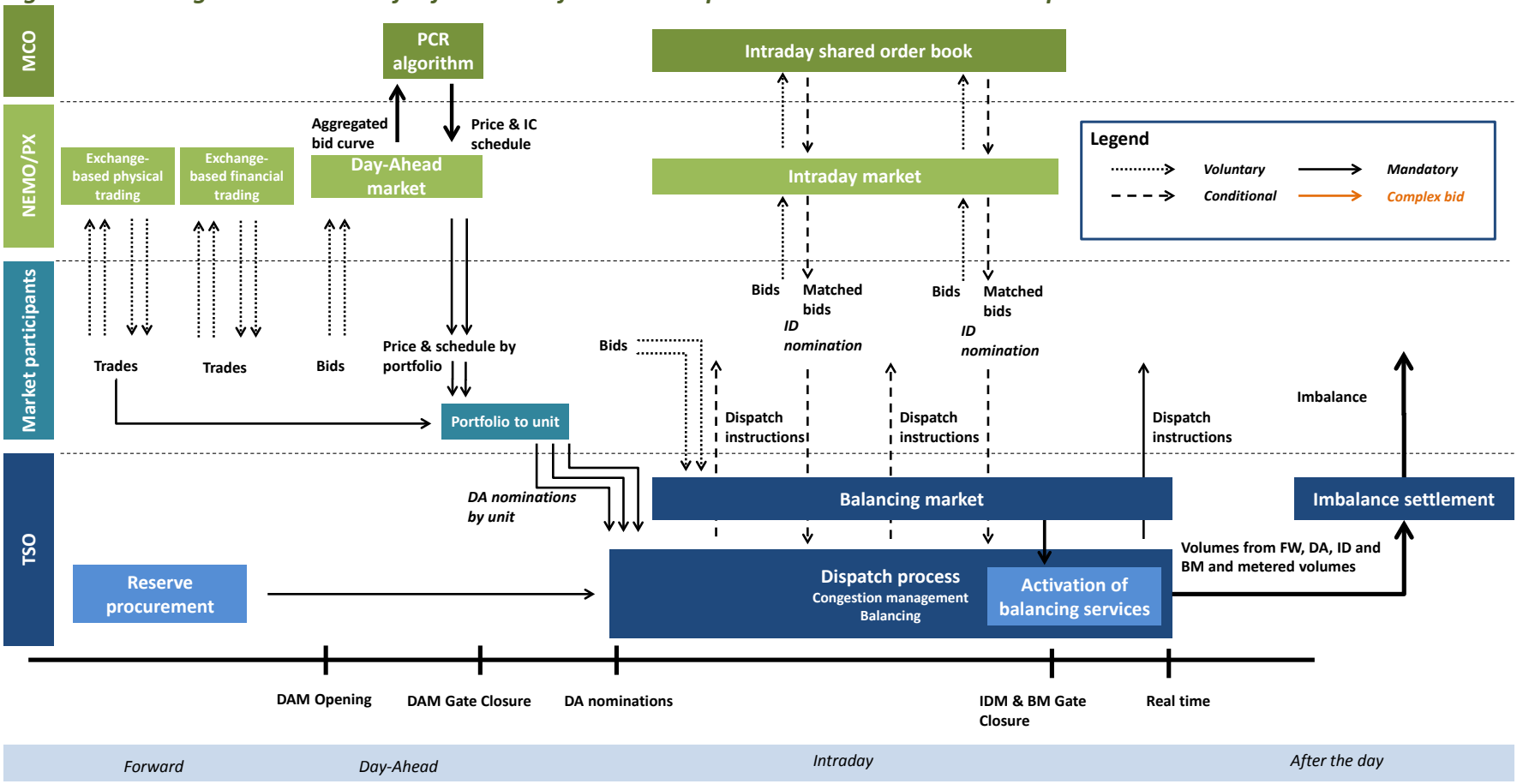
6.3.12 Participation in this balancing mechanism is voluntary up to the gate closure of the ID market but mandatory after the ID GC. Mandatory in this timeframe means that all market participants with technical capabilities to regulate either upwards or downwards within the time between ID GC and real-time must participate. Generating units with priority dispatch status are exempt from participating.

6.3.13 Bids take the form of simple incremental and decremental bids (incs and decs) from market participants, which can be updated on a continual basis (at least up to balancing market bidding GC). Bids accepted by the TSO for energy balancing purposes in each period are settled ex-post at the price of the marginal energy balancing action activated by the TSO in each trading period (i.e., each half hour).

6.3.14 All market participants are balance responsible although they can nominate a BRP to act on their behalf. This means that all volumes not settled through the energy market (or activated by the TSO) are settled at an imbalance price in each period. This imbalance price is set at the price of the marginal energy balancing action activated by the TSO in each period. Either a single price or a dual price imbalance settlement can be accommodated.

6.3.15 Figure 9 summarises the timing and direction of flows of information between the different stakeholders in the all island electricity market under the Adapted Decentralised Market option.

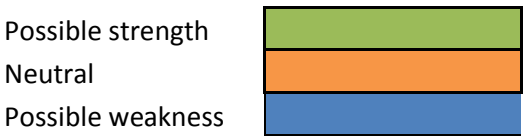
Figure 9 – Timing and direction of information flows in Adapted Decentralised Market option



6.4 QUALITATIVE ASSESSMENT OF ADAPTED DECENTRALISED MARKET

6.4.1 We now describe our qualitative assessment of the relative strengths and weaknesses of the Adapted Decentralised Market against the HLD criteria. This assessment is done with consideration for this option on its own rather than comparatively against the other options for energy trading arrangements.

6.4.2 Table 5 summarises the initial qualitative assessment of the relative strengths and weaknesses of this option. In this table, the following colour-coding is used:



6.4.3 Table 5 highlights that the Adapted Decentralised Market has the potential to score strongly across a number of the criteria if the adaptations to promote liquidity in the DAM and IDM are effective (e.g. market maker obligations on some or all participants and gross portfolio bidding).

6.4.4 The adaptations should help to provide a route to market for a wide range of market players to enable them to take greater commercial responsibility for balancing the energy system, as well facilitating effective competition through greater transparency, easier market monitoring and more effective cross-border trade.

Table 5 – Summary assessment of the Adapted Decentralised Market

SoS		Can be delivered by this option
Stability		Depends on regulatory intervention needed to deliver liquid DAM and IDM
Efficiency		Can be delivered by this option
Practicality		Not a particular strength or weakness of this option
Equity		If liquid, DAM and IDM provide some routes to markets, with more cost targeting
Competition		Depends on effectiveness of competition from greater choice of trading strategies
Environment		Wind exposed to imbalance prices, which can be managed if liquid IDM
Adaptive		Governance processes to be determined during detailed design phase
IEM		Liquidity promoting measures should facilitate efficient DAM flows

Security of supply: the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.

6.4.5 The discussion here is around the context in which security of supply would be delivered under this option, with respect to short-term issues (TSO actions, and interconnector flows) and longer-term issues (signals for long-term entry and exit).

6.4.6 One of the possible issues for this option is that the degree of trading in the voluntary forward and day-ahead markets will affect the quality of the information that would be provided by market participants for the TSO's planning at the day-

ahead stage which could affect the TSO's ability to manage operational security of supply. However, it is likely that market participants will want to secure significant volumes before the intraday market, whether that is through the European day-ahead market, or forward (bilateral or exchanged based) contracting.

6.4.7 In this option, the TSO will have scope and tools to take action before the IDM gate closure, including through a Balancing Mechanism that will start operation after the DA stage. In some cases, these tools could possibly include longer-term actions where most efficient and consistent with the TSO's own regulatory framework – for example, a long-term contract could be struck in response to a constraint problem (to avoid the TSO having to constrain certain production down on the day repeatedly). Conversely, there is increased emphasis on market participants taking responsibility for the delivery of balanced energy position, which may reduce the need for TSO intervention.

6.4.8 As a mitigation measure in this option, market participants are required to provide nominations (which will be unit-based for production above a de-minimis level) to the TSO on the afternoon/early evening of D-1 (for a trading day starting at 2300) with updates provided within the day. The concept of Balance Responsibility means that these nominations should reflect the cumulative position of all trades matched by that stage (whether in forward, day-ahead or intraday timescales). It is likely that market participants will want to secure significant volumes before the intraday market, whether that is through the European day-ahead market, or forward (bilateral or exchanged based) contracting.

6.4.9 One specific issue for this option is that the allowance of portfolio bids into the DAM means that additional time will be needed to allow market participants to convert portfolio-based results into unit-based nominations. This is a process that is followed in other European markets, with the exact format and timing of the submission of the unit nominations varying by markets.

6.4.10 The question is the extent to which the particular nature of the SEM as a small synchronous system means that there is a greater need for the TSO to receive the physical nominations (covering the market schedule at least) earlier than in other markets allowing for early TSO actions due to locational issues.

6.4.11 In this option, the interconnector flows would be fully integrated into the nominations process – so that where there is a change in flow, balance responsibility should mean that there should be a matched nomination (whether for generation or demand). Therefore, this means that there would not necessarily need to be a TSO dispatch instruction in response to any change in the scheduled flow.

6.4.12 The liquidity of the DAM in this option will be important in determining the incentives from the energy market for new entry (or exit) – for example, by providing strong and robust reference price to support forward trading.

Stability: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.

6.4.13 The assessment of this HLD criterion focuses the extent to which a final HLD will be in line with historical expectations, and how robust (as much as possible) it may be to any future changes (.e. g. in national or European policy, or in the physical or structural aspects of the market). An additional aspect is the potential impact on (perceived) regulatory risk by the degree of additional ex-ante regulation required in any option.

6.4.14 It will be important to get market participants' views in relation to this criterion as it specifically relates to their expectations of the regulatory process. The future existence and design of any CRM will also be relevant to an assessment of stability, which is separate to the consideration of an individual energy trading option that we are discussing at this stage.

6.4.15 This option would represent the most change from the current SEM, for example with a move away from any mandatory markets (with imbalance being used to settle volumes neither matched in any ex-ante markets nor resulting from trades with the SO).

6.4.16 However, with sufficient liquidity in the DAM (and IDM), then there will still be a strong reference price in the SEM with good access to market for non-portfolio players. This then raises the question of the stability and predictability of any measures put in place to deliver liquid trading in these markets.

6.4.17 This option shares many similarities with the existing design of markets in the North West Europe region, which may make it easier to adapt to any agreed European approach to market design changes in the medium-term at least.

Efficiency: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.

6.4.18 In this option, there is a move away from the current central dispatch arrangements in the SEM (through a gross mandatory pool with complex bids). There may be some centralisation of the commitment and dispatch process in this option if there is a highly liquid DAM[30] (in particular) and the IDM (as opposed to nominations being

[30] The February 2013 Next Steps Decision Paper described the European DAM as essentially being a centralised market.

driven by direct bilateral trades or management of a vertically integrated portfolio). In addition, the Balancing Mechanism is open for participation from the day-ahead stage onwards, but only on a voluntary basis[31].

6.4.19 Even with a liquid DAM and IDM, decentralised elements remain in the ability of market participants to convert portfolio-based results in the DAM and IDM into unit-based physical nominations.

6.4.20 Of particular relevance for the all island market in reaching an efficient dispatch position is the efficiency of the unit commitment process. In this option, unit commitment can be primarily determined on a portfolio basis by market participants (even to meet a portfolio schedule determined through the 'centralised' DAM).

6.4.21 One possible issue for this option with respect to the efficiency of dispatch is the liquidity of the DAM price based on voluntary trading, and the extent to which that provides an effective signal for demand side response to participate in the energy market. The market coupling at DA and ID stages will bring liquidity from GB (subject to the limitations of the available interconnector capacity) in addition to the liquidity promoting measures at the core of this option).

6.4.22 The consideration of non-energy factors (e.g. reserve or locational issues) in the dispatch position produced by the initial nominations from market participants will depend on the arrangements in place for the procurement of these services (e.g. any contracts struck with the TSO before the day-ahead stage etc.).

Practicality/Cost: the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced

6.4.23 The costs of implementation and participation need to be considered from the perspective of central systems and the direct costs to market participants.

6.4.24 In all of the options for energy trading arrangements, market participants are likely to require some new systems or interfaces (or participate through an intermediary if this is permitted) if they wish to participate in the European DAM and/or IDM. Similarly, central systems will need to be developed and/or procured to allow all island market participants to access the European markets. However, the systems are similar to ones used in a number of other European markets so more standardised solutions may be available. For effective participation in a continuous IDM, 24 hour trading functionality is likely to be a requirement (which again could be delivered by an intermediary).

[31] Submission of balancing bids and offers only becomes mandatory (for participants technically able to do so) from the gate closure of the IDM.

6.4.25 From a system perspective, the design of the balancing mechanism in this option is simpler than a set of pool arrangements, which should result in a lower procurement cost than pool-based options.

Equity: the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner

6.4.26 There are two main aspects to the assessment of equity – the first is about the equality of access to different markets for a range of market participants, and the second is the delivery of an allocative efficient outcome where prices reflect marginal costs (including some allowance for the risk of provision where appropriate). Obviously, the energy trading arrangements are not the only determinant of equity – for example, other energy policies address the issue of including externalities (such as CO_2) in market prices.

6.4.27 The ability for a wide range of market participants to access the ex-ante markets will particularly depend on the liquidity of the DAM and the IDM that emerge in this option. If these markets are not liquid because of the ability of market participants to choose the market in which they trade, then there may be some advantages to portfolio players.

6.4.28 The amount of interconnector capacity available in the DAM and IDM will help to increase the liquidity of those markets (in addition to any domestic participation). If more PTRs are allocated in forward timeframes, then there may be less interconnector capacity may be available (in one direction) for the DAM and IDM (depending on the extent to which flows are nominated on the basis of PTRs).

6.4.29 In this option, the imbalance price is intended to reflect the marginal cost to the SO of balancing the residual difference between (unconstrained) energy supply and demand (i.e. the physical volumes neither settled in an ex-ante market nor on the basis of a trade with the TSO for system purposes). The imbalance price is then paid by the parties responsible for those residual volumes. This should then provide a financial incentive (in addition to the obligation of balance responsibility) for market participants to take more responsibility for helping to deliver a balanced system through their nominations (i.e. the imbalance price means that the imbalance market is effectively the market of last resort).

6.4.30 This then should help IDM prices to reveal the true value of within-day flexibility (as opposed to being socialised through the operation of an ex-post pool) as that would be one of the main ways for variable generators and demand to manage their imbalance exposure (which should be reflective of the cost of managing the overall system imbalance). Therefore, the delivery of an equitable outcome in this regard will be heavily dependent on the liquidity of the IDM (in terms of access for a wide range of buyers and sellers of flexibility) that emerges in this option.

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

6.4.31 This option is designed to provide market participants with a wider range of possible trading and risk management strategies, including for example more choice of which timeframes to trade in, and greater scope for optimisation within different portfolios. This could also include participation of non-physical players (with no requirement for unit-based bidding) which could increase market liquidity.

6.4.32 In theory, this should enable market participants to be innovative in terms of trading strategies (which could include different approaches to trading wind generation for example), with benefits for consumers either in terms of lower costs and/or more attractive products and services. In addition, the ability to choose a trading strategy could also act as a constraint on the exercise of market power – e.g. if there is gaming in a particular market, then participation may decline which mitigates the negative impact of the gaming.

6.4.33 The challenge for this option is to what extent the nature of the all island market (e.g. size, high wind penetration, current market shares, etc.) may mean that in practice significant regulatory intervention would still be needed to create the conditions for effective competition (e.g. is the market large enough to allow market participants more freedom over where to trade?). Depending on this requirement, then as the degree of intervention increases, this reduces the choices available to market participants in determining their competitive strategy.

6.4.34 It is also important that stakeholders have confidence that the conditions are in place for effective competition (which helps to support efficient new entry for example). In this regard, the transparency of trading behaviour and outcomes has been seen as important in the SEM. This means that ultimately, the degree of intervention needed in this option will depend on where trading is concentrated. This will affect the barriers to entry, and the ease and nature of market monitoring. For example, if this option led to high levels of trading outside of centralised markets such as power exchanges (whether in forward or intraday timescales), that would be negative for transparency of trading and would present more barriers to a route for market for smaller players.

6.4.35 Therefore, the strength of this option with respect to competition will largely be determined by the liquidity of the trading by all island market participants in the European DAM and the IDM (which in part will be determined by the success of the 'liquidity-promoting measures' envisaged as a core port of option). This would be supported by the competitive constraint of interconnector flows scheduled through 'centralised' market coupling arrangements. If trading is concentrated in the European markets, then the power exchanges operating these markets can also support the regulators' market monitoring activities, as market surveillance is

typically a key activity of the European power exchanges.

6.4.36 Otherwise, there is likely to be pressure for additional intervention to more strongly regulate the behaviour of participants, which would reduce the perceived benefits of this option.

Environmental: while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.

6.4.37 In general, the use of a Balancing Mechanism (with marginal imbalance prices) has been seen as negative for intermittent generation sources such as wind. This is because it exposes the wind generation to the impact of it being less predictable closer to real time, compared to present arrangements in which these costs are socialised.

6.4.38 This option respects the concept of absolute priority dispatch status by requiring the TSO to accommodate physical output from generating units with priority dispatch, apart from exceptional circumstances when economic factors may be used.

6.4.39 Commercially, this means that the wind generation is regarded as a price-taker in the imbalance arrangements, which would typically provide a less attractive price for wind than an ex-post pool. It is important for wind to able to manage this risk by trading in a liquid DAM and IDM.

6.4.40 The combination of imbalance arrangements with liquid IDM should help to reveal greater value for flexibility within the energy trading arrangements. This should in turn encourage greater flexibility from both generation and demand.

6.4.41 This may reduce the need for separate mechanisms (outside or on top of the energy trading arrangements) to be put in place to incentivise the delivery of the flexibility (within market timescales[32)] required to help the system accommodate higher levels of wind.

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

6.4.42 The governance arrangements for any set of trading arrangements tend to be determined at the implementation stage, i.e. a level of detail below the HLD. Therefore, adaptability is typically not a major distinguishing feature of different energy trading arrangements.

32 i.e. it wouldn't provide value for flexibility very close to real-time.

6.4.43 In this option, there is expected to be less reliance on specific local arrangements for the majority of physical trading – if there is liquid DAM and IDM, then most of the trading will happen on the organised European markets. This could make it harder to make all island specific changes to the trading arrangements, but does mean that any changes should be coordinated across Europe.

The Internal Electricity Market: the market design should efficiently implement the EU Target Model and ensure efficient cross border trade

6.4.44 The February 2013 Next Steps Decision Paper stated that the revised HLD must be able to comply fully and efficiently with the specifications set out in the following five pillars of the EU Target Model :

- **Capacity Calculation and Zones Delimitation** – this option is compatible with requirements, although concerns about the scope for effective competition in the energy trading arrangements (as opposed to locational balancing actions) may be even greater in this option if the SEM is split into multiple zones;
- **Cross Border Forward Hedging and Harmonisation of Capacity Allocation Rules** – the option uses PTRs, which are allowed under the Forward Capacity Allocation Network Code, with the rules and processes for allocation to be confirmed as part of the implementation and ongoing operation of the revised HLDs;
- **Day Ahead Market Coupling** – complies with the requirement for a single day-ahead price coupling;
- **Intra Day Continuous Trading** – complies with the requirement for continuous implicit allocation of cross-zonal capacity, and could support periodic auctions alongside the continuous trading; and
- **Cross Border Balancing** – balancing mechanism should support compliance but further details will need to be addressed (e.g. in terms of Standard Products) during more detailed design and implementation.

6.4.45 The liquidity-promoting measures in this option should facilitate efficient cross-border trade, at least in terms of the level of participation in the DAM and IDM in the I-SEM – as the overall efficiency of flows is somewhat dependent on the liquidity of the GB market. In addition, we consider any problems for the options in relation to complying with the European requirement for the implementation of the new HLD by 1 January 2017. Although this option will require significant new systems, these already exist in a number of other European markets, which means that they could be effectively 'bought off the shelf'.

6.4.46 The detailed design of any regulatory measures to promote liquidity in the DAM would need to be finalised as part of the implementation phase of this revised HLD.

7 OPTION 2: MANDATORY EX-POST POOL FOR NET VOLUMES

7.1 CONSULTATION QUESTIONS FOR MANDATORY EX-POST POOL FOR NET VOLUMES

7.1.1 The following consultation questions relate to the issues discussed in this section:

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

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

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

7.2 OVERVIEW OF MANDATORY EX-POST POOL FOR NET VOLUMES

7.2.1 This option is characterised by a pool-based approach to the determination of dispatch, and ex-post prices and volumes. There is some choice for market participants around their physical trading in the DA and ID timeframes. This could encourage greater participation of demand side units in the market on the basis of a firm DA price.

7.2.2 Under this option, market participants can make firm ex-ante trades in forward, DA and ID timescales. These trades are then used to support unit-based nominations from market participants to the TSO as the starting point for its dispatch process. The dispatch process is integrated with an ex-post pool based on complex bids submitted by all generating units. This means that where a volume has been nominated for a generating unit, the complex bid should reflect the costs of reducing production from the nominated level (which could be an avoided start cost or a positive shut-down cost depending on whether the plant is physically committed). The pool is an attempt to manage the schedule and dispatch in an integrated fashion, given the differences between the current market schedule and dispatch.

7.2.3 Therefore, this option offers a choice to market participants of whether to trade physically in the ex-ante markets (up to a certain volume) and/or an ex-post pool, which is designed to act as a back-up route to market for non-portfolio players in the all island Market.

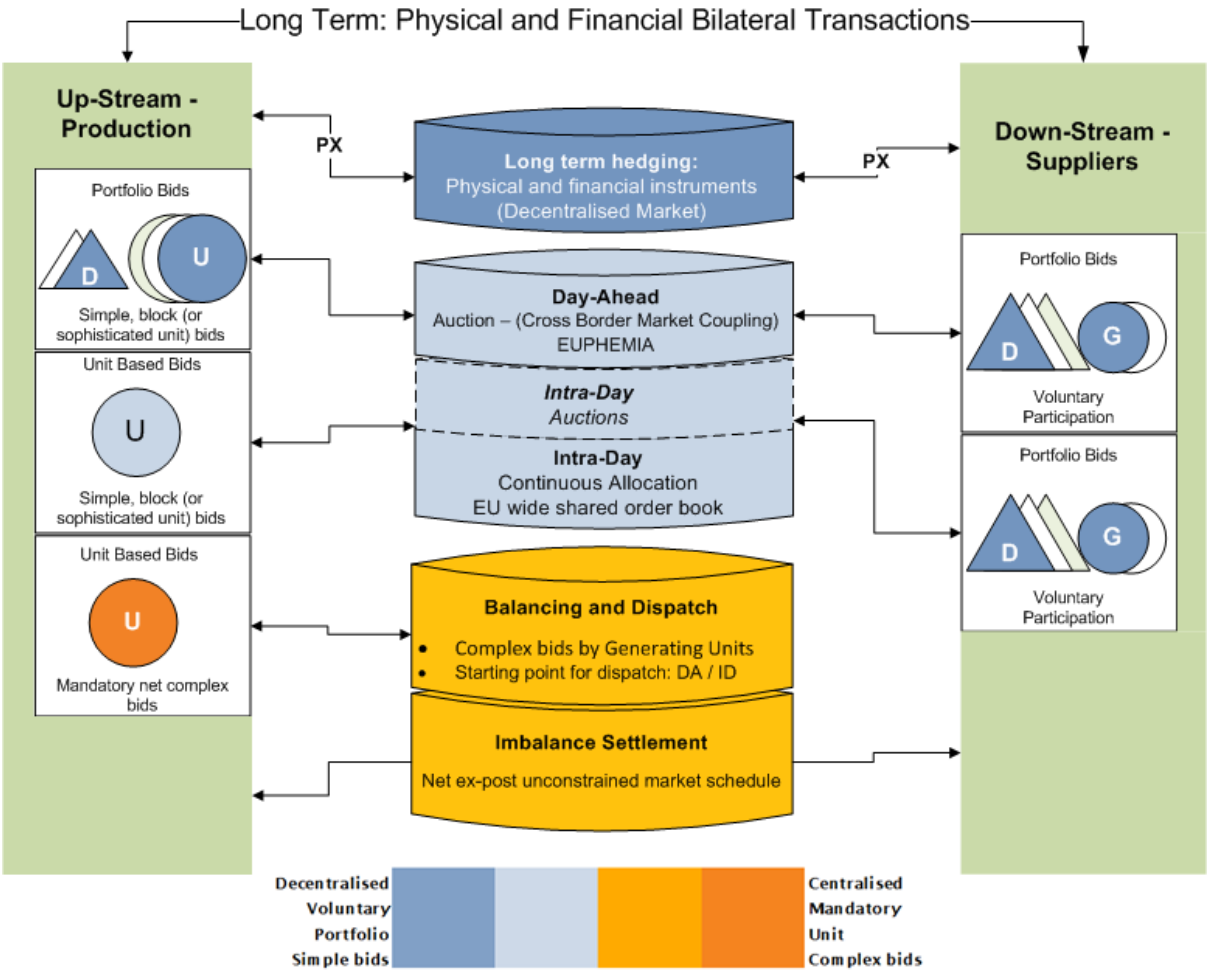
7.2.4 The trading in the ex-ante markets could be limited up to a 'regulated' limit on the level of trading (which is expected to be more limited than say in the Adapted Decentralised Market). The effect of a regulated limit will be to ensure sufficient liquidity in the ex-post pool and the volume of the nominations received by the TSO

to ensure that the perceived benefits of the pool process with respect to efficiency unit commitment can be realised (given the importance of start up and part loading costs in the All-Island Market). This limitation can be imposed to specific units, specific portfolios, and specific market participants or can be market-wide.

7.2.5 This option can be seen as an implementation of the EU Target model on top of an ex-post pool as known in the SEM today. This option will implement the EU Target model in the ex-ante physical markets (DAM and IDM) but still retains the ex-post pool as an important trading platform. A main difference from the current market is that the ex-post pool will be a net pool in the place of the current gross pool.

7.2.6 A simplified illustration of this option is presented in Figure 10.

Figure 10 – Overview of Mandatory ex-post Pool for Net Volumes



7.3 DESCRIPTION OF MANDATORY EX-POST POOL FOR NET VOLUMES

7.3.1 All forward, DA and ID trading is portfolio-based, although market participants' have the discretion to submit unit-based bids into the DAM and IDM. All generating unit bids into the pool (for the ex-post schedule and dispatch) are unit-based.

7.3.2 We now describe how this option operates from the forward timescales onwards. Figure 11 summarises the timing and direction of flows of information between the different stakeholders in the SEM under the Mandatory Ex-post Pool for Net Volumes option.

7.3.3 In the forward timeframe, market participants can trade both physical energy and financial products through an intermediate agent (e.g., broker or power exchange), or directly with another market participants. A robust financial derivatives market (futures and forwards) allows for price hedging whilst mitigating the risk of market participants not trading physical volumes in the DAM and promoting liquidity in the short-term physical markets.

7.3.4 Physical Transmission Rights (PTRs) with UIOSI provisions at the DA Stage are used for supporting long-term cross-border trading.

7.3.5 All bids into the voluntary DAM are submitted to the NEMO (the market operator under the European market coupling arrangements). The NEMO in its turn transfers the same bid in an anonymised form to the PCR algorithm (Euphemia). This returns the DAM price (as a firm ex-ante price), and the volumes and interconnector flows to be settled at that price. The results are provided to market participants on a portfolio basis where portfolio bids were submitted, and a unit basis where unit bids were submitted.

7.3.6 Market participants in their turn nominate the units and the corresponding output level of each one that will be used for respecting their individual DAM (portfolio) schedule to the TSO. This would be done by the early evening of D-1 (for a trading starting at 23.00 UTC). Nominated volumes (traded up to and including DAM) are the starting point of the dispatch process.

7.3.7 The TSO is responsible for ensuring a feasible dispatch (based on minimising costs of deviating from the nominated positions) accounting for the complex bids submitted by market participants, which can be updated during the day. For a generating unit with a nominated volume this means a complex bid with an associated shut-down cost (instead of a start-up cost).

7.3.8 The TSO takes relevant actions and issues dispatch instructions for ensuring system security whilst respecting absolute priority dispatch for RES. The TSO can take balancing actions or even re-commit plants upon receiving DA nominations from market participants.

7.3.9 Market participants are responsible for updating their nominated positions to the TSO to reflect changes intraday (up to the limit on total nominated volumes), which could result from inter alia:

- matching of bids in the European intraday market;
- rebalancing within their own portfolio (e.g. to balance change in plant availability or updated wind forecast); and
- direct trading with other market participant in Ireland outside of the continuous matching algorithm.

7.3.10 Intraday trading through the European market coupling arrangements is done on a continuous basis, although periodic intraday auctions could be accommodated. Market participants can start trading in the IDM upon nominating DAM volumes. When trading continuously market participants submit simple unit bids into the IDM.

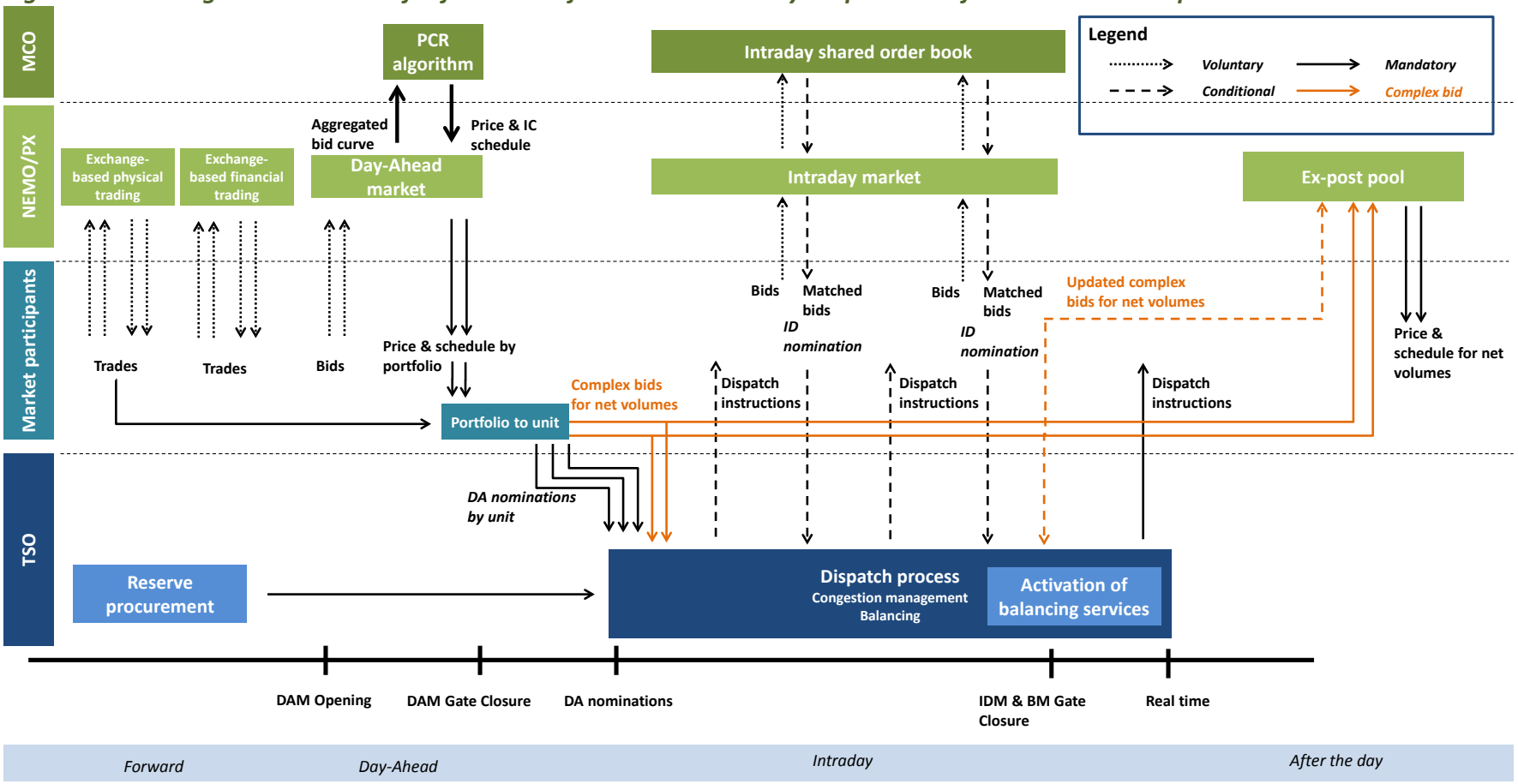
7.3.11 Periodic intraday auctions could be accommodated within this approach. Indeed, updating dispatch instructions based on complex bids (up and down) is likely to require the TSO to run its optimisation process in the pause in continuous intraday trading that has been proposed to support periodic intraday auctions. This pause is likely to be relatively short (say 15 minutes) which will limit the run-time and scope of the dispatch algorithm.

7.3.12 Depending on the intraday nominations and as other information becomes available (plant availability, updated intermittent generation forecast etc.), the TSO can potentially issue updated dispatch instructions based on the mandatory net complex bids submitted for the ex-post pool.

7.3.13 Cross-border balancing is based on the complex bids that are initially submitted and thereafter updated. These are translated by the TSO to Standard Products that can be used for trading balancing energy cross-border.

7.3.14 All volumes scheduled in the ex-post pool are settled at the ex-post prices determined by the ex-post unconstrained pool. The use of net complex bids could raise challenges for the calculation of a single ex-post price (covering energy, start-up and no-load costs), because the calculation of uplift typically assumes that plants are all being scheduled upwards.

Figure 11 - Timing and direction of information flows in Mandatory ex-post Pool for Net Volumes option



7.4 ASSESSMENT OF MANDATORY EX-POST POOL FOR NET VOLUMES

7.4.1 We now describe our qualitative assessment of the relative strengths and weaknesses of the Mandatory Ex-Post Pool for Net Volumes against the HLD criteria. This assessment is done with consideration for this option on its own rather than comparatively against the other options for energy trading arrangements.

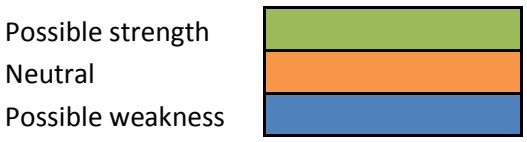
7.4.2 This option combines physical trading in the European DAM and IDM with a net mandatory pool for dispatch and ex-post pricing based on complex bids.

7.4.3 This means there are effectively two markets competing for primacy in the trading of physical volumes because there is a trade-off between liquidity in the ex-ante markets, particular the European DAM, and the amount of commitment that is carried out in the pool. This means that the liquidity of the different ex-ante markets, particularly the liquidity of the DAM will then determine the effectiveness of the pool-based arrangements.

7.4.4 If there is high liquidity in the DAM and the IDM, then the pool-based arrangements will only apply to a small fraction of physical volumes, reducing the benefits of having pool-based arrangements, which are more complicated than a simple balancing mechanism. This may raise stability issues if regulatory intervention is triggered to limit the amount of physical volume traded outside the pool (which is a symptom of the challenges of managing a hybrid system of this nature).

7.4.5 On the other hand, if there is limited liquidity in the DAM in particular, then that reduces the quality of the price, and may reduce the efficiency of interconnector flows if they are determined by a relatively thin market.

7.4.6 Table 6 summarises the initial qualitative assessment of the relative strengths and weaknesses of this option. In this table, the following colour-coding is used:



7.4.7 Table 6 highlights the importance of the balance between physical trading in the pool and in the European markets. If one market place predominates, then this option becomes very similar to at least one of the other options. Therefore, there may be significant regulatory intervention required to maintain a balance between physical trading in the pool and in the European markets, which may raise concerns about the stability of the arrangements.

Table 6 – Summary assessment of the Mandatory ex-post Pool for Net Volumes

SoS		Can be delivered by this option
Stability		Difficult to manage balance between pool and European markets
Efficiency		Can be delivered by this option
Practicality		Depends on balance of physical trading between pool and European markets
Equity		Liquidity may be split between pool and European markets
Competition		Depends on balance of physical trading between pool and European markets
Environment		Depends on balance of physical trading between pool and European markets
Adaptive		Not a particular strength or weakness of this option
IEM		Net pool not fit neatly into either a balancing market, or fully integrated dispatch

Security of supply: the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.

7.4.8 The discussion here is around the context in which security of supply would be delivered under this option, with respect to short-term issues (TSO actions, and interconnector flows) and longer-term issues (signals for long-term entry and exit).

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7.4.9 In this option, the TSO will have scope and tools to take action before the IDM gate closure, primarily through a mandatory net pool that will start operation after the DA stage, with submission of complex bids by generation units, and use of central wind and demand forecasts from the TSO. This should increase the access of the TSO to a wider range of resources to manage the system.

7.4.10 The TSO may also be able to take longer-term actions where most efficient and allowed under its regulatory framework – e.g. in response to a constraint problem (to avoid the TSO having to constrain certain production down on the day repeatedly).

7.4.11 One of the possible issues for this option is that quality of the information that would be provided by market participants for the TSO's planning at the day-ahead stage which could affect the TSO's ability to manage operational security of supply. This will be affected by the degree of trading in the forward and day-ahead markets, which are voluntary. However, it is likely that market participants will want to secure significant volumes before the intraday market, whether that is through the European day-ahead market, or forward bilateral contracting.

7.4.12 Therefore, as a mitigation measure in this option, market participants will be required to provide nominations (which will be unit-based for production above a de-minimis level) to the TSO on the afternoon/early evening of D-1 (for a trading day starting at 2300) with updates provided within the day.

7.4.13 At the day-ahead stage, additional time will be needed to allow market participants to convert portfolio-based results into unit-based nominations. This is a process that is followed in other European markets, with the exact timing of the submission of

the unit nominations varying by markets. The question is the extent to which the particular nature of the SEM as a small synchronous system means that there is a greater need for the TSO to receive the physical nominations earlier than in other markets -allowing for early TSO actions due to locational issues. This may be particularly the case in this option when a net pool also needs to be run to inform at least (some) unit commitment.

7.4.14 In the intraday market, unit-based bidding is mandated which means that any changes in unit nominations resulting from a matched trade in the European intraday market can be sent to the TSO at the same time as to the market participant.

7.4.15 One of the relative disadvantages of this option is that the flows would not be fully integrated into the pool process for dispatch (as they are inputs into the process rather than being determined within the pool itself). Where there is a change in flow, balance responsibility should mean that there should be a matched nomination (whether for generation or demand). This would therefore mean that the pool is not the sole determinant of physical nominations from the day-ahead stage onwards, which may reduce the benefits of having a pool-based arrangement for balancing the system within day.

7.4.16 In this option, there are two potential reference prices for supporting new entry to boost longer-term security of supply – the DAM and the ex-post pool. The relative liquidity in each market will determine which one is better in providing a reference price to support forward financial trading, noting that as uncertainties crystallise; ex-post markets are expected to reflect greater volatility than day-ahead.

Stability: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.

7.4.17 It will be important to get market participants' views in relation to this criterion as it specifically relates to their expectations of the regulatory process. The future existence and design of any CRM will also be an important aspect of stability, which is separate to the consideration of an individual energy trading option.

7.4.18 This option combines a pool-based approach for dispatch and ex-post pricing with voluntary physical ex-ante trading in forward timeframes, and in the European DAM and IDM. The use of a pool-based approach allows the retention of complex bid structure for dispatch and ex-post pricing (but not in the European DAM and IDM) although market out-turns may be different depending on the arrangements put in place for recovery of start-up and no-load costs associated with (net) complex bids.

7.4.19 The main question is where the liquidity emerges – e.g. if there is high liquidity in the DAM and IDM, does this reduce the effectiveness of the ex-post pool? This means that there may be the risk of greater regulatory intervention over time in face of the trade-off between sufficient liquidity in the DAM (and IDM) – given the importance of a robust firm ex-ante price – and ensuring that commitment of sufficient volumes is determined within the pool to make these arrangements worthwhile (and avoid the systems becoming largely redundant). This may increase the perceived instability of the trading arrangements.

7.4.20 Furthermore, these are ultimately a hybrid set of arrangements – as typified by simultaneous nature of IDM and balancing arrangements with different bid structures. Over time it may be more difficult to maintain a coherent set of arrangements under a hybrid-type approach in response to new market design challenges, whether at a national or European level.

Efficiency: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.

7.4.21 In this option, there is mandatory participation for generating units based on complex bids submitted after the day-ahead stage and updated throughout the day. The major difference in this option compared to current arrangements is that plants can provide physical nominations to provide a starting point above zero into the pool – these physical nominations will be based on trades outside the pool, whether in forward timescales or in the European DAM (allowing for portfolio-based bidding) and IDM.

7.4.22 Of particular relevance for the all island market in reaching an efficient dispatch position is the efficiency of the unit commitment process. In this option, the full (three part) complex commercial bids currently used in the SEM are used for unit commitment within the pool. Therefore, the degree to which initial unit commitment (in the form of physical nominations) is centralised will depend on the amount of trading outside the pool, particularly in the forward and DAM. The impact of this on actual physical commitment will depend on the timing of the trades and the physical notice needed by plant.

7.4.23 One possible issue for this option with respect to the efficiency of dispatch is the liquidity of the DAM price based on voluntary trading (supported by up to 950MW of interconnection capacity, compared to average demand of 3.9GW in the all-island market), and the extent to which that provides an effective signal for demand side response to participate in the energy market.

Practicality/Cost: the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced

7.4.24 The costs of implementation and participation need to be considered from the perspective of central systems and the direct costs to market participants. In all of the options for energy trading arrangements, market participants are likely to require some new systems (or participate through an intermediary if this is possible) if they wish to participate in the European DAM and/or IDM. Similarly, central systems will need to be developed and/or procured to allow all island market participants to access the European markets.

7.4.25 However, the systems are similar to ones used in a number of other European markets so more standardised solutions may be available. For effective participation in a continuous IDM, 24 hour trading functionality is likely to be a requirement (which again could be delivered by an intermediary).

7.4.26 In this option, the ex-post pool provides market participants with a greater choice of whether or not to participate in the European markets. However, the costs of participation in the European markets may be higher for generating units because of the need to maintain parallel systems for IDM and for the pool (mandatory after the day-ahead stage) with quite different bid structures.

7.4.27 Despite superficial similarities, the data flows and pricing algorithm involved in the pool may require a substantial change from that of today to allow for the net pool concept and are likely to be unique worldwide, particularly if the concept of uplift is retained for the recovery of start-up and no-load costs.

Equity: the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner

7.4.28 There are two main aspects to the assessment of equity – the first is about the equality of access to different markets for a range of market participants, and the second is the delivery of an allocative efficient outcome where prices reflect marginal costs (including some allowance for the risk of provision where appropriate). Obviously, the energy trading arrangements are not the only determinant of equity – for example, other energy policies address the issue of including externalities (such as CO_2) in market prices.

7.4.29 In terms of access to the different energy markets, there remains an ex-post pool which provides one route to market open to all market participants, with limited advantages for portfolio players.

7.4.30 The access to the ex-ante markets will depend on the liquidity of the DAM and the IDM that emerge in this option. There is a trade-off between the 'attractiveness' of the pool price, and the strength of the financial incentive for market participants to trade in the DAM and IDM to manage their exposure to the pool price. The latter factor will be an important determinant of the liquidity of the DAM and IDM, and therefore the ability of a wide range of market participants to access these markets.

7.4.31 The amount of interconnector capacity available in the DAM and IDM will help to increase the liquidity of those markets (in addition to any domestic participation). If more PTRs are allocated in forward timeframes, then there may be less interconnector capacity available (in one direction) for the DAM and IDM (depending on the extent to which flows are nominated on the basis of PTRs).

7.4.32 The use of complex three part commercial bids into the pool means that there will need to be a mechanism for the recovery of start and no-load costs. This can be done through uplift arrangements (to produce a single SMP covering SRMC, start and no-load costs) or through make-whole payments for individual units. Consideration would need to be given how this is addressed in the implementation of the pool in this option.

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

7.4.33 Under this option, it is uncertain where the focus for competition for physical volumes would be as there is a tension between the (ex-post) net pool, and other markets (including the European DAM and IDM).

7.4.34 This means that in theory there is some choice for market participants around where to trade physical volumes. However, in practice, it is likely that the market will concentrate either outside the pool or inside the pool. If it concentrates outside the pool, this may lead to pressure for regulatory intervention to limit choice for market participants outside of the pool. If it concentrates in the pool, then this may limit the liquidity of the ex-ante markets including the European DAM and IDM.

7.4.35 If physical trading concentrates in the pool, this would provide a route to market (with a strong reference price) for independent and small generators or suppliers, similar to the arrangements in the SEM. If physical trading is outside the pool, then the question is whether it concentrates in the DAM, which could provide a strong reference price; or bilateral trading, which may support more innovative trading or credit arrangements but which may reduce the access to market for smaller players.

7.4.36 It is also important that stakeholders have confidence that the conditions are in place for effective competition (which helps to support efficient new entry for example). In this regard, the transparency of trading behaviour and outcomes has been seen as important in the SEM. The requirement for complex (unit-based) bids and mandatory participation in the net pool means that there is a high transparency of bidding in this option, which would facilitate ex-post market monitoring. If ex-ante bidding regulation was judged to be necessary, then this may be easier with a system of complex bids.

7.4.37 If more physical volumes are concentrated in the DAM and IDM, then the power exchanges operating these markets can also support the regulators' ex-post market monitoring activities, as market surveillance is typically a key activity of the European power exchanges.

Environmental: while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.

7.4.38 For this option, the impact on wind will be determined by where the physical trading is concentrated. If physical trading is concentrated in the pool, then this may be seen as positive for intermittent generation sources such as wind. This is because the price formation in the pool (based on out-turn availability) shields the wind generation from the impact of it being less predictable closer to real time (and effectively socialising the energy balancing costs across all market participants). The pool can also provide a commercial benefit for plant with priority dispatch status as they can be regarded as price-takers in the pool.

7.4.39 However, the converse of this is that the wind does not face commercial incentives from the market to increase its predictability closer to real time (e.g. through more accurate forecasts), and that the flexible resource required to manage the variations in wind output do not receive the full value of this flexibility (in the pool price).

7.4.40 If in this option, trading is concentrated outside the pool, then this may encourage wind generators to procure flexibility to avoid being exposed to a more volatile pool prices. If this is possible through liquid intraday markets, this should then provide market-based signals for the value of flexibility, which may reduce the need for additional mechanisms for the central procurement and/or payments for flexibility.

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

7.4.41 This is because the governance arrangements for any set of trading arrangements tend to be determined at the implementation stage, i.e. a level of detail below the HLD. Therefore, adaptability is typically not a major distinguishing feature of different energy trading arrangements.

7.4.42 In this option, the governance issues will depend on whether the physical trading is concentrated inside or outside the pool. If it is inside the pool, then it may be easier to make all island specific changes (whilst still needing to comply with the requirements of the European Network Codes, particular in relation to Electricity Balancing). However, it may be harder to coordinate these changes with developments across Europe.

The Internal Electricity Market: the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.

7.4.43 The February 2013 Next Steps Decision Paper stated that the revised HLD "must be able to comply fully and efficiently with the specifications set out in the following five pillars of the EU Target Model[33]:

Capacity Calculation and Zones Delimitation – option is compatible with requirements, and could work with a number of zones;

Cross Border Forward Hedging and Harmonisation of Capacity Allocation Rules – the option uses PTRs, which are allowed under the Forward Capacity Allocation Network Code, with the rules and processes for allocation to be confirmed as part of the implementation and ongoing operation of the revised HLDs;

[33] Section 11 contains a list of documents that can provide further details on the European Electricity Target Model.

Day Ahead Market Coupling – complies with the requirement for a single day-ahead price coupling;

Intra Day Continuous Trading – could comply with the requirement for continuous implicit allocation of cross-zonal capacity, although the parallel operation of a mandatory net pool in the intraday timeframe may work better if there are periodic auctions alongside the continuous trading (which would allow a pause in continuous trading to allow the running of the pool); and

Cross Border Balancing – the pool should be able to support compliance but further details will need to be addressed (e.g. in terms of ability to convert pool bids to/from Standard Products) given that it does not fall naturally in a 'traditional' balancing mechanism or the 'gross' pool associated with the specific integrated scheduling and dispatch arrangements (allowed for markets designated to be central dispatch).

The efficiency of cross-border trade in this option will depend on the liquidity of the DAM and IDM in terms of the all island electricity market and in GB. There may be a trade-off between a desire for liquidity in the DAM (and IDM), and for the pool to be the main determinant of unit commitment.

7.4.44 In addition, we consider any problems for the options in relation to complying with the European requirement for the implementation of the new HLD by 1 January 2017.

7.4.45 Although this option will require significant new systems to support participation in European DAM and IDM, these already exist in a number of other European markets, which means that they could be effectively 'bought off the shelf'. In addition, there may need to be major changes to existing SEM systems (e.g. introduction of physical nominations and net complex bids into the pool, possible changes to the recovery of start and no-load costs, changes to the timing of bid resubmissions), which could represent rather time-consuming modifications.

7.4.46 The detailed design of any regulatory measures to promote liquidity in the European Day Ahead Markets would need to be finalised as part of the implementation phase of this revised HLD.

8 OPTION 3: MANDATORY CENTRALISED MARKET

8.1 CONSULTATION QUESTIONS FOR MANDATORY CENTRALISED MARKET

8.1.1 The following consultation questions relate to the issues discussed in this section:

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

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

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

8.2 OVERVIEW OF MANDATORY CENTRALISED MARKET

8.2.1 This option emphasises the significance of the DAM and IDM as the main markets for ex-ante physical trading by mandating participation in these markets.

8.2.2 The strong DAM price may help to incentivise demand side management, with the DAM schedule forming a good starting point for a feasible initial dispatch. There is also mandatory submission of bids into the Balancing Mechanism from the DA stage onwards. This is intended to help the TSO to manage the gap between schedule and dispatch within the All-Island market.

8.2.3 As the only way of changing intraday nominations, the IDM is designed to be liquid and transparent to allow participants, including higher levels of wind, to trade out changes from the DAM in advance of the balancing timeframe.

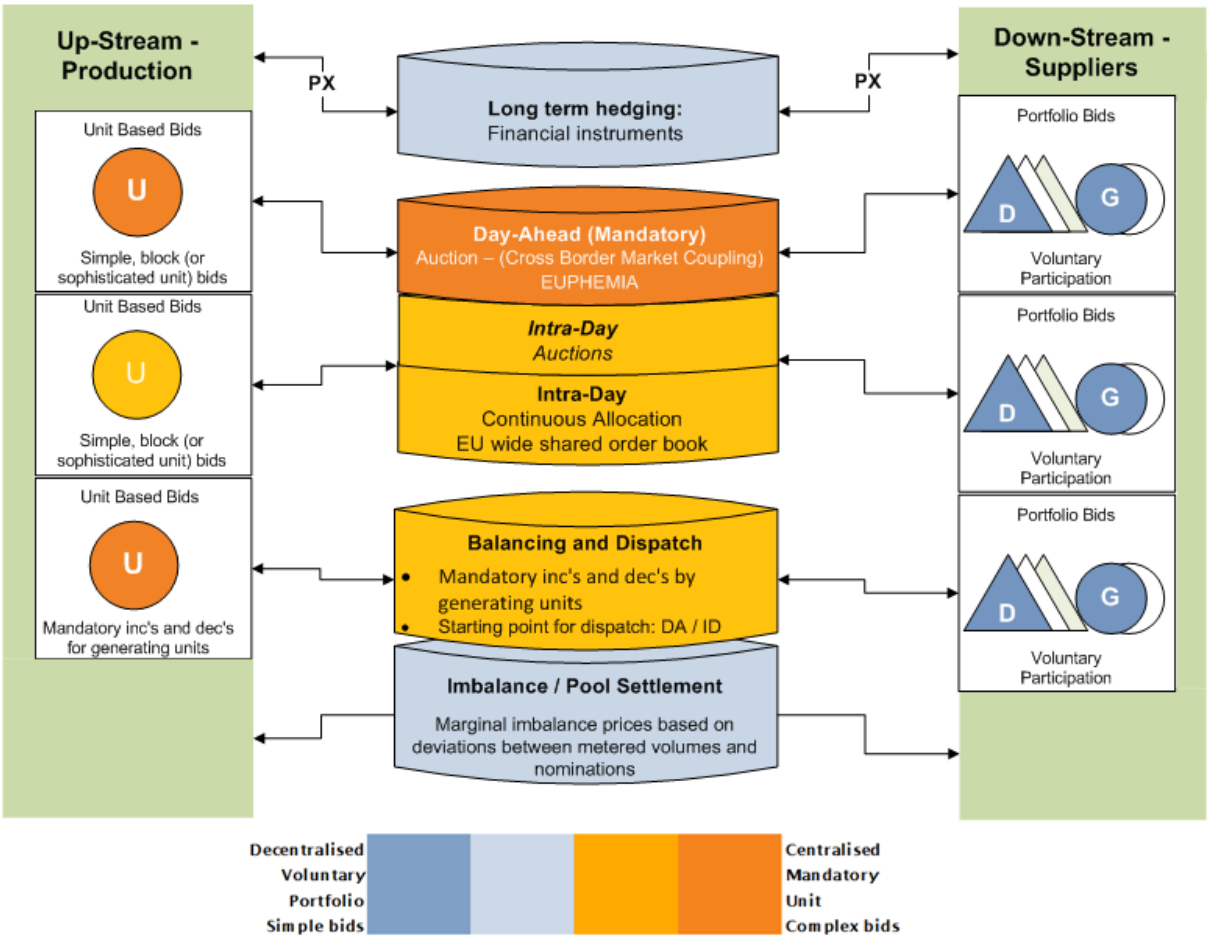
8.2.4 The reliance on sophisticated unit-based bids into the DAM is designed to help the results of the DAM to reflect (some) technical plant constraints as well as helping market participants to manage the risks around start-up and no-load costs.

8.2.5 This option is close to the design of electricity markets in the NWE region, which are built on the concept of a liquid DAM, and also similar to the Iberian market in particular which exhibits high liquidity in the DAM and IDM.

8.2.6 It does not retain most of the current systems implemented for SEM and will therefore present a change for both central stakeholders like SEMO and the TSOs as well as market participants.

8.2.7 A simplified illustration of this option is presented in Figure 12.

Figure 12 – Overview of Mandatory Centralised Market



8.3 DESCRIPTION OF MANDATORY CENTRALISED MARKET

8.3.1 We now describe how this option operates from the forward timescales onwards. Figure 13 summarises the timing and direction of flows of information between the different stakeholders in the all island electricity market under the Mandatory Centralised Market option.

8.3.2 In order to encourage liquidity in the day-ahead market, no physical trading is allowed in the forward timeframe, though participants would be free to trade financial contracts.

8.3.3 Financial Transmission Rights (FTRs) are used to allow market participants to hedge price risk associated with financial forward trading across bidding zones.

8.3.4 Mandatory participation in the DAM means the following for different types of market participants:

- thermal generating units have to submit bids for their expected availability
- RES have to submit bids based on forecasted output for intermittent RES and based on availability for controllable RES or with absolute priority dispatch submit an expected output
- demand has to submit bids for the forecasted demand level (forecast carried out by each individual market participant representing demand)

8.3.5 The enforcement of mandatory participation will be based on best endeavour for wind and demand. Market monitoring can use different practices to ensure accurate forecasts by market participants.

8.3.6 Trading in the DAM is unit-based and allows for sophisticated bids. All bids, including bids by the demand side, are submitted to the NEMO (the market operator under the European market coupling arrangements). The NEMO in its turn transfers exactly the same bid in an anonymised form to the PCR algorithm (Euphemia). This returns the DAM price (as a firm ex-ante price) and the volumes and interconnector flows to be settled at that price.

8.3.7 The scheduled production volumes are notified to market participants on a unit basis, which means that the schedule from the European DAM can be passed directly to the TSO to effectively act as the nominations for the starting point of the dispatch process.

8.3.8 The TSO is responsible for ensuring a feasible dispatch (based on minimising costs of deviating from the results of the DAM and IDM). Initial dispatch instructions are based on the technical plant information and the same bids submitted in the DAM, which include demand side bids. This means that the balancing mechanism is based on mandatory participation from the DA stage onwards (on the basis of 'technical availability' and subject to a de-minimis level).

8.3.9 The TSO assesses the feasibility of the market schedule, takes relevant actions if necessary and issues dispatch instructions for ensuring system security, and respecting absolute priority dispatch As in all the options, the TSO takes into account its own forecasts for generation availability (including renewables) and demand in issuing this dispatch instructions.

8.3.10 Market participants are responsible for updating their nominated positions to the TSO to reflect changes intraday. These changes to nomination can only result from the matching of (unit-based) bids in the European intraday market as that is the only (exclusive) route to changing intraday nominations in this option.

8.3.11 Intraday trading through the European market coupling arrangements is done on a continuous basis, although periodic intraday auctions could be accommodated. Market participants can start trading in the IDM upon nominating DAM volumes.

When trading continuously market participants submit simple unit bids. Under this option, ID trading takes place exclusively through the IDM.

8.3.12 If periodic auctions are to be implemented, this might allow for more sophisticated unit-based bids to be used (with the results of the IDM feeding directly into changes into market participants nominated volumes to the TSO).

8.3.13 Depending on the intraday nominations and as other information becomes available to the TSO (plant availability, updated intermittent generation forecast etc.), the TSO can, if required, issue updated dispatch instructions (even before the ID gate closure).

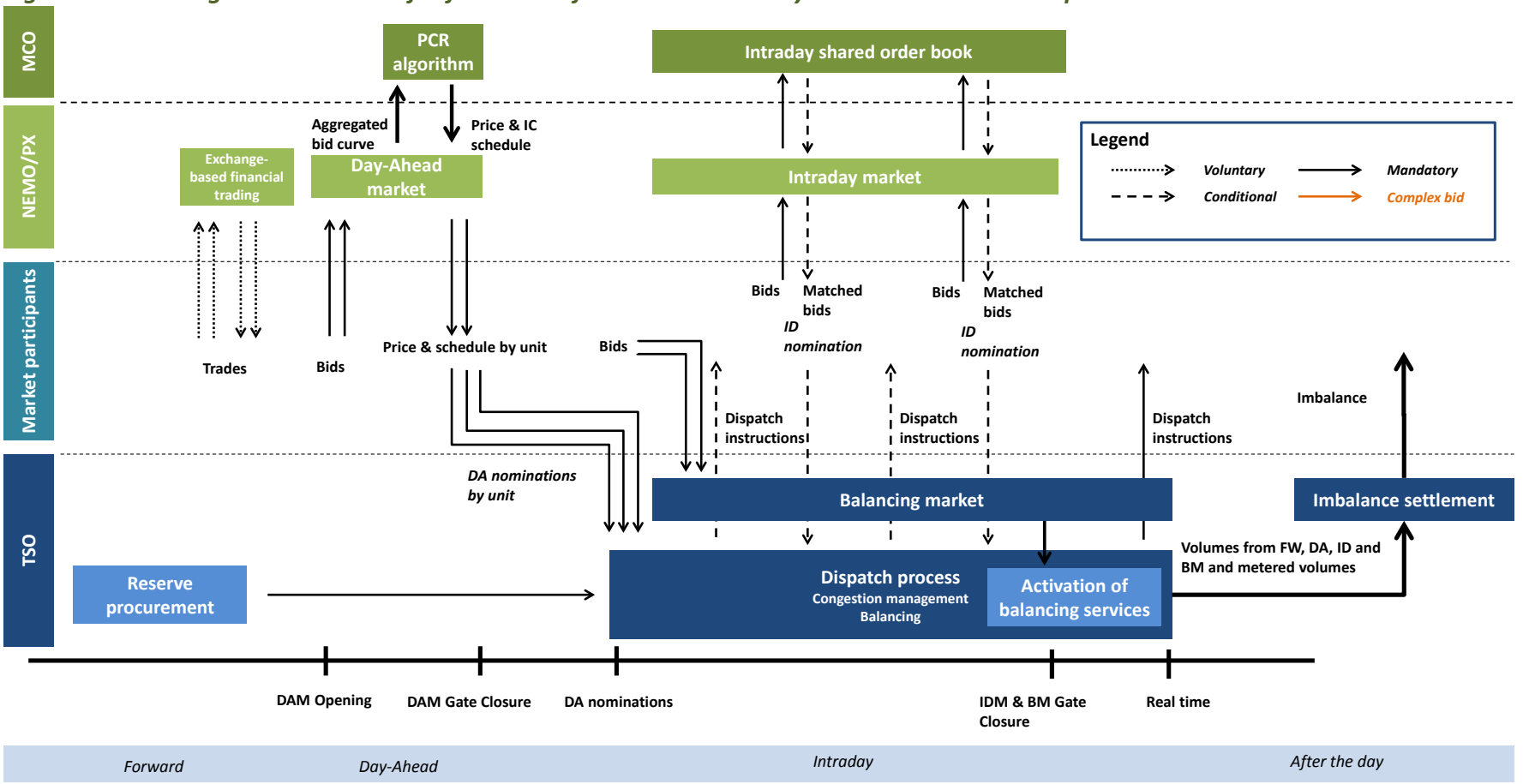
8.3.14 These dispatch instructions can use the bids submitted by market participants into the separate mandatory Balancing Mechanism operated by the TSO in parallel with the intraday market. The balancing mechanism is mandatory up to technical availability (e.g. suppliers only have to submit volumes to be called in the balancing mechanism where the demand can actually be flexible).

8.3.15 This separate Balancing Mechanism will need to accommodate at least one of the Standard Products defined for the activation of balancing energy at a European level. This balancing mechanism is one of the tools that the TSO has to ensure secure system operation as well as energy balance at all times.

8.3.16 Bids into the Balancing Mechanism take the form of simple incremental and decremental bids (incs and decs) from market participants, which can be updated on a continual basis (at least up to intraday gate closure). Bids accepted by the TSO for energy balancing purposes in each period are settled ex-post at the price of the marginal energy balancing action activated by the TSO in each period.

8.3.17 All market participants are balance responsible. This means that all volumes not settled through the energy market (forwards, DAM and IDM) are settled at an imbalance price in each trading period. This imbalance price is set at the price of the marginal energy balancing action activated by the TSO in each period.

Figure 13 – Timing and direction of information flows in Mandatory Centralised Market option



8.4 ASSESSMENT OF THE MANDATORY CENTRALISED MARKET

8.4.1 We now describe our qualitative assessment of the relative strengths and weaknesses of the Mandatory Centralised Market against the HLD criteria. This assessment is done with consideration for this option on its own rather than comparatively against the other options for energy trading arrangements.

8.4.2 Ultimately, the performance of this option will be determined by the assessment of the benefits and costs of using the European day-ahead and intraday markets (rather than a pool with complex bidding) as a 'centralised' market. These markets will provide the main reference price (from the DAM), be the route to market for a wide range of market participants for initial scheduling and intraday adjustment of position, as well as the providing the (initial) information and bids/offers for the TSO to use in dispatch.

8.4.3 Associated with this is a consideration of the ease, transparency and stability of any monitoring and enforcement arrangements put in place to support the mandatory participation in the DAM.

8.4.4 Table 7 summarises the initial qualitative assessment of the relative strengths and weaknesses of this option. In this table, the following colour-coding is used:

Possible strength
Neutral
Possible weakness

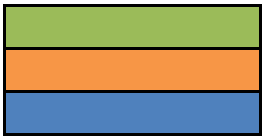


Table 7 – Summary assessment of the Mandatory Centralised Market

SoS		Can be delivered by this option
Stability		Depends on regulatory intervention needed to enforce ADM and IDM rules
Efficiency		Can be delivered by this option
Practicality		Not a particular strength or weakness of this option
Equity		DAM and IDM provide route to markets, with more targeting of costs
Competition		Could be strong within 'approved' market places, with high transparency
Environment		Wind exposed to imbalance prices, which can be managed in liquid IDM
Adaptive		Not a particular strength or weakness of this option
IEM		Compliant with requirements, with DAM/IDM supporting effective flows

Security of supply: the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.

8.4.5 The discussion here is around the context in which security of supply would be delivered under this option, with respect to short-term issues (TSO actions, and interconnector flows) and longer-term issues (signals for long-term entry and exit).

8.4.6 Participation in the DAM is mandatory which should improve the quality of the information provided by market participants for the TSO's planning at the day-ahead stage (as it will be based on a 'complete' market schedule). In addition, the requirement for unit-based nominations into the DAM and the IDM (above a de minimis level) means that the unit-based results can be sent directly to the TSO at the same time as to market participants, avoiding any lag in the conversion from portfolio-based results into unit-based nominations.

8.4.7 One of the relative strengths of this option is that the flows would be fully integrated into the nominations process – so that where there is a change in flow, balance responsibility should mean that there should be a matched nomination (whether for generation or demand). Therefore, this means that there would not necessarily need to be a TSO dispatch instruction in response to any change in the scheduled flow.

8.4.8 Mandatory participation in the DAM may be helpful in by providing strong and robust reference price that could help to support new entry.

Stability: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.

8.4.9 It will be important to get market participants' views in relation to this criterion as it specifically relates to their expectations of the regulatory process. The future existence and design of any CRM will also be an important aspect of stability, which is separate to the consideration of an individual energy trading option.

8.4.10 This option retains reliance on a centralised scheduling approach, although through the European DAM (and IDM) rather than through an all island pool.

8.4.11 Looking forward, the question for stability is the regulatory framework put in place to mandate participation in the DAM – for example, with questions, such as the:

- the monitoring of the volumes submitted by demand and by variable generation, such as wind based on day-ahead forecasts;
- the monitoring of bid and offers by market participants; and
- any rules around the bidding allowed from any plant that may have pre-contracted with the TSO to provide ancillary services, such as reserve, (where such arrangements exist).

Efficiency: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant.

8.4.12 Of particular relevance for the All-Island market in reaching an efficient dispatch position is the efficiency of the unit commitment process. In this option, sophisticated unit-based bids into the DAM are used as the prime determinant of unit commitment –these have been developed in other markets to allow market

participants to manage the risk of start-up costs (in the optimisation by Euphemia across a whole trading day), without requiring the full (three part) complex bids currently used in the SEM (as the sophisticated bids effectively act as a proxy for the full complex bids). In the European IDM, bids are expected to be less sophisticated even with periodic auctions, given the limited run times possible for any algorithm operating close to real-time.

8.4.13 This option should deliver a strong DAM price that could provide an effective signal for demand side response to participate in the energy market.

Practicality/Cost: the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced

8.4.14 The costs of implementation and participation need to be considered from the perspective of central systems and the direct costs to market participants.

8.4.15 In this option, participation in the European DAM is mandatory (above a de-minimis level), and participation in the European IDM is the only way to adjust physical nominations within-day. Therefore, all market participants will face the costs of participating in the European markets (whether direct or through an intermediary). Similarly, central systems will need to be developed and/or procured to allow all island market participants to access the European markets.

8.4.16 However, the systems are similar to ones used in a number of other European markets so more standardised solutions may be available. For effective participation in a continuous IDM, 24 hour trading functionality is likely to be a requirement (which again could be delivered by an intermediary).

8.4.17 In all four options for energy trading arrangements, market participants are likely to require some new systems (or contract with intermediaries) if they wish to participate in the European DAM and/or IDM. In this option, participation is mandatory – however, in practice, the participation costs may not be so different if highly liquid DAM and IDM develop under the other options.

8.4.18 From a system perspective, the design of the balancing mechanism in this option is simpler than a set of pool arrangements, which should result in a lower procurement cost than pool-based options.

Equity: the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner

8.4.19 There are two main aspects to the assessment of equity – the first is about the equality of access to different markets for a range of market participants, and the second is the delivery of an allocative efficient outcome where prices reflect

marginal costs (including some allowance for the risk of provision where appropriate). Obviously, the energy trading arrangements are not the only determinant of equity – for example, other energy policies address the issue of including externalities (such as CO_2) in market prices.

8.4.20 In this option, the DAM is mandatory, and the IDM is the only place for market participants to change physical nomination within-day. In addition, all physical interconnector capacity should be available for the DAM and IDM as FTRs rather than PTRs are used as long-term cross-border hedging tools. This should support a high level of liquidity in these markets, which should provide access to market in these timescales for a wide range of market participants. The requirement for unit-based bidding into the DAM and IDM will also reduce the benefits of being a portfolio player.

8.4.21 In this option, the imbalance price is intended to reflect the marginal cost to the SO of balancing the residual difference between (unconstrained) energy supply and demand (i.e. the physical volumes neither settled in an ex-ante market nor on the basis of a trade with the TSO for system purposes). The imbalance price is then paid by the parties responsible for those residual volumes. This should then provide a financial incentive (in addition to the obligation of balance responsibility) for market participants to take more responsibility for helping to deliver a balanced system through their nominations (i.e. the imbalance price means that the imbalance market is effectively the market of last resort).

8.4.22 This then should help IDM prices to reveal the true value of within-day flexibility (as opposed to being socialised through the operation of an ex-post pool) as that would be one of the main ways for variable generators and demand to manage their imbalance exposure (which should be reflective of the cost of managing the overall system imbalance – with mandatory provision of bids into the balancing market from the DAM onwards in this option).

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

8.4.23 This option is designed to focus competition for physical volumes in the European DAM and IDM, where the interconnector capacity is fully integrated into the market arrangements and hence can help to provide a competitive constraint on possible market power. This would provide routes to market for independent and small generators or suppliers (assuming that the mandatory participation requirement can be effectively enforced). In addition, a reliable DA price may increase the participation of the demand side.

8.4.24 It is also important that stakeholders have confidence that the conditions are in place for effective competition (which helps to support efficient new entry for

example). In this regard, the transparency of trading behaviour and outcomes has been seen as important in the SEM. The requirement for unit-based bidding in the DAM and the IDM increases the transparency of bidding in this option. In addition, the power exchanges operating the European DAM and IDM can also support the regulators' market monitoring activities, as market surveillance is typically a key activity of the European power exchanges.

8.4.25 However, the requirements for trading to be in certain markets and in certain forms (unit-based) reduce the ability for (some) market participants to be innovative in their trading strategies (for example to suit their attitude to risk). The requirement for unit-based bidding could also provide a barrier to the participation of non-physical players. The mandating of participation in the DAM may also increase the potential gains if a market player is able to successfully game that market. However, these concerns need to be balanced against the potential gaming that may arise in other options.

Environmental: while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.

8.4.26 In general, the use of a balancing mechanism (with marginal imbalance prices) has been seen as negative for intermittent generation sources such as wind. This is because it exposes the wind generation to the impact of it being less predictable closer to real time. This option respects the concept of absolute priority dispatch status by requiring the TSO to accommodate physical output from generating units with priority dispatch, apart from exceptional circumstances when economic factors may be used. Commercially, this means that the wind generation is regarded as a price-taker in the imbalance arrangements, which would typically provide a less attractive price for wind than an ex-post pool.

8.4.27 However, the converse of this is that the wind faces commercial incentives from the market to increase its predictability closer to real time (e.g. through more accurate forecasts), and that the flexible resource required to manage the within-day variations in wind output may be able to capture (at least some of) the value of this flexibility from a liquid IDM (assuming that it is able to efficiently reflect this value in its bids into the mandatory DAM).

8.4.28 In this option, the fact that the IDM is exclusive should support the development of a liquid IDM, which will also increase the opportunities for wind to manage its imbalance exposure. In addition, having access to a mandatory DA market and a liquid IDM may encourage improvements in wind forecasting as it increases the commercial value of accurate forecasts. This should reduce the need for separate mechanisms (outside or on top of the energy trading arrangements) to be put in

place to incentivise the delivery of the flexibility (within market timescales[34]) required to help the system accommodate higher levels of wind.

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

8.4.29 The governance arrangements for any set of trading arrangements tend to be determined at the implementation stage, i.e. a level of detail below the HLD. Therefore, adaptability is typically not a major distinguishing feature of different energy trading arrangements. This option relies on the European DAM and IDM for the majority of physical trading. This could make it harder to make all island specific changes to the trading arrangements, but does mean that any changes should be coordinated across Europe.

The Internal Electricity Market: the market design should efficiently implement the EU Target Model and ensure efficient cross border trade.

8.4.30 The February 2013 Next Steps Decision Paper stated that the revised HLD must be able to comply fully and efficiently with the specifications set out in the following five pillars of the EU Target Model[35]:

- **Capacity Calculation and Zones** – option is compatible with requirements;
- **Cross Border** Forward Hedging and Harmonisation of Capacity Allocation Rules – the option uses FTRs, which are allowed under the Forward Capacity Allocation Network Code, with the rules and processes for allocation to be confirmed as part of the implementation and ongoing operation of the revised HLDs;
- Day Ahead Market Coupling – complies with the requirement for a single day-ahead price coupling;
- **Intra Day Continuous Trading** – complies with the requirement for continuous implicit allocation of cross-zonal capacity, and could support periodic auctions alongside the continuous trading; and
- **Cross Border Balancing** – balancing mechanism should support compliance but further details will need to be addressed (e.g. in terms of Standard Products) during more detailed design and implementation.

[34] i.e. it wouldn't provide value for flexibility very close to real-time.

[35] Section 11 contains a list of documents that can provide further details on the European Electricity Target Model.

8.4.31 The mandatory nature of the DAM and the exclusive nature of the IDM (combined with FTRs) would be expected to facilitate efficient cross-border trade (at least from the perspective of the all island market – as the overall efficiency of flows is somewhat dependent on the liquidity of the GB market).

8.4.32 In addition, we consider any problems for the options in relation to complying with the European requirement for the implementation of the new HLD by 1 January 2017. Although this option will require significant new systems, these already exist in a number of other European markets, which means that they could be effectively 'bought off the shelf'.

8.4.33 The detailed design of the measures to enforce mandatory participation in the DAM and exclusivity of the IDM liquidity would need to be finalised as part of the implementation phase of this revised HLD.

9 OPTION 4: GROSS POOL – NET SETTLEMENT MARKET

9.1 CONSULTATION QUESTIONS FOR GROSS POOL – NET SETTLEMENT MARKET

9.1.1 The following consultation questions relate to the issues discussed in this section:

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

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

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

9.2 OVERVIEW OF GROSS POOL – NET SETTLEMENT MARKET

9.2.1 This option relies on a centralised, pool-based approach to the determination of dispatch and ex-post prices and volumes (e.g. through complex bidding into an integrated scheduling and dispatch process to help the TSO reach a least-cost dispatch).

9.2.2 The centralised approach means that an ex-post pool based around complex bids becomes the 'ultimate' market. This makes it the focus of market power mitigation measures, as well providing an attractive route to market for variable generation including wind farms.

9.2.3 The unit commitment and dispatch process of all generating units in this option s is determined by the pool process. Generating units have to submit complex bids in order to produce an ex-post unconstrained schedule for the entirety of the market (subject to de-minimis limits).

9.2.4 There is choice for market participants around voluntary financial trading in the DA and ID timeframes (including trading over the interconnector), but that trading has no direct impact on their physical positions within the all island market (although it does affect the physical flows on the interconnector) – i.e. trading in the ex-ante markets does not affect nominations provided by individual market participants to the TSO, who schedules and dispatches the system to minimise the overall cost of production based on the bids into the pool (respecting however, scheduled cross-border flows).

9.2.5 The results of the ex-ante markets do however affect the settlement in the ex-post pool. The ex-post price is only applied to volumes that are scheduled in the ex-post

pool but have not been matched in the ex-ante markets. This is a net settlement process. This means that a market participant with a trade from the DAM or IDM gets its price from the ex-ante markets for the volumes traded there, and receives the ex-post pool price for deviations.

9.2.6 One of the main issues for this type of market arrangements is how to ensure liquidity in the ex-ante markets. Even though trading in the ex-ante markets are financial and all physical volumes in the ex-post pool, it is important to have sufficient liquidity in the ex-ante markets to ensure optimal flow on the interconnector.

9.2.7 Therefore, an option would be to implement specific measures to encourage liquidity in the DAM as a key trading platform under the EU Target Model. These could include market maker obligations on some or all participants, as well as gross portfolio bidding.

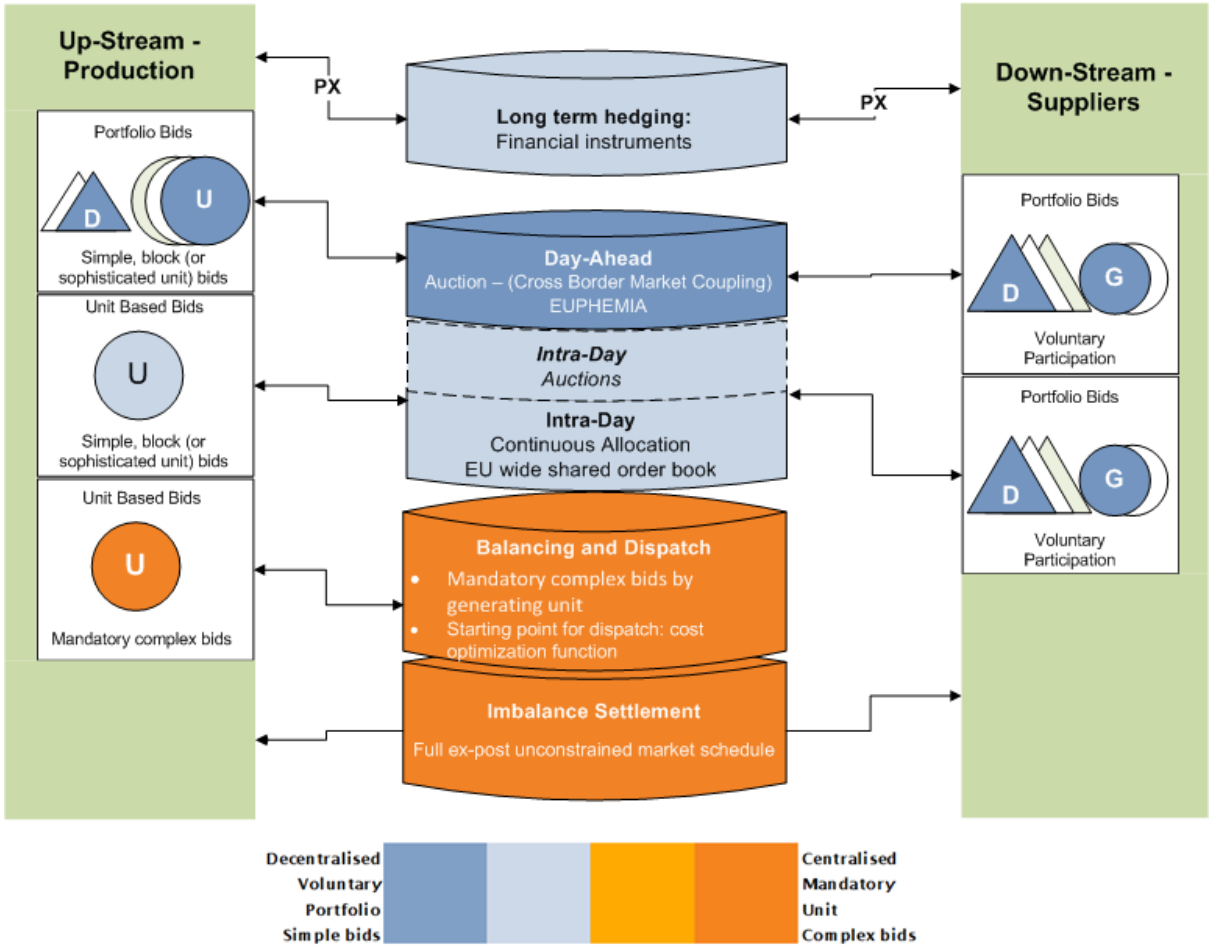
9.2.8 This option is the one closest to the current SEM when compared to the other three options. It retains an ex-post gross mandatory pool as the main physical market as well as central dispatch. The European ex-ante markets are implemented as financial markets and thereby only affect the market participants' financial settlement.

9.2.9 However, this option could still represent significant change from the current SEM arrangements with respect to:

- the application of ex-ante bidding principles (if any);
- IC flows which will be determined by the DAM and IDM;
- new opportunities for risk hedging (e.g. financial DAM and IDM);
- recovery of start up and no load costs in the pool;
- operation of CRM (where it exists).

9.2.10 A simplified illustration of this option is presented in Figure 14

Figure 14 – Overview of Gross Pool – Net Settlement Market



9.3 DESCRIPTION OF GROSS POOL – NET SETTLEMENT MARKET

9.3.1 We now describe how this option operates from the forward timescales onwards. Figure 15 summarises the timing and direction of flows of information between the different stakeholders in the all island electricity market under the Gross Pool – Net Settlement option.

9.3.2 This option has forward trading of financial products ahead of the DAM. The main purpose of such markets is to give market participants the opportunity to have a long-term hedge against price risk in the real-time markets (as reflected in the ex-post price).

9.3.3 Financial Transmission Rights (FTRs) are used to allow market participants to hedge price risk associated with financial forward cross-border trading (based on the reference price from the Day-Ahead market). All (portfolio) bids into the voluntary DAM are submitted to the NEMO (the market operator under the European market coupling arrangements). The NEMO in its turn transfers exactly the same bid in an anonymized form to the PCR algorithm (Euphemia) that returns a DAM price and the IC schedule.

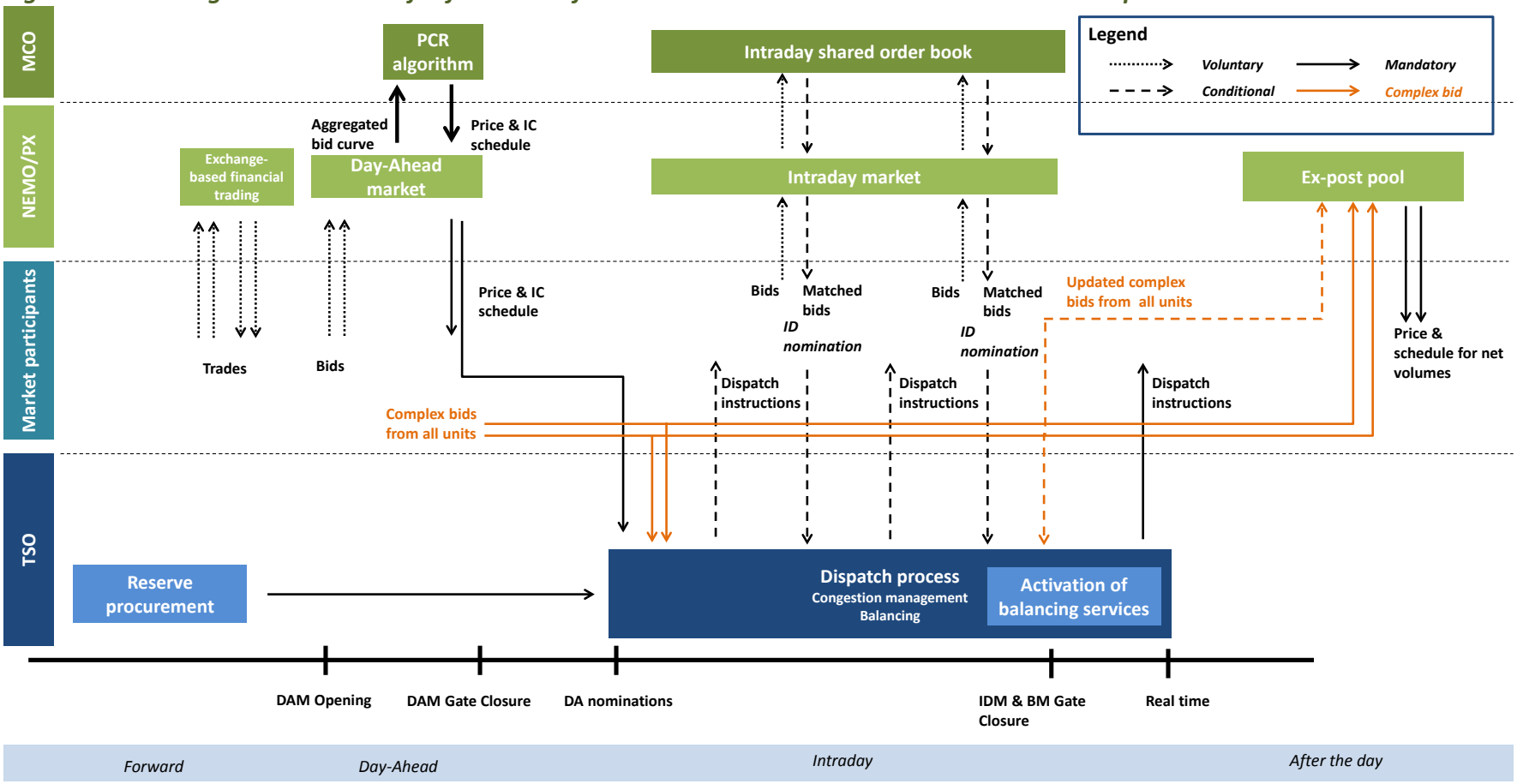
9.3.4 The resulting IC schedule is nominated directly to the TSO and acts as the starting point of the dispatch. Alongside the bids submitted to the DAM, market participants submit unit-based complex bids to NEMO, who runs the ex-post pool, and to the TSO. The TSO carries out an Integrated Scheduling Process based on those complex bids and other technical plant characteristics whilst respecting the IC schedule and issues initial dispatch instructions (which includes respecting absolute priority dispatch). Market participants can also submit updated complex bids to the TSO in relevant windows.

9.3.5 In the intraday timeframe market participants can trade financial contracts both continuously or participate in periodic auctions (if they exist) in order to refine their position. In the case where these financial trades result in a change in the IC schedule, an updated IC schedule is nominated to the TSO.

9.3.6 There is no separate Balancing Mechanism in place and all energy balancing actions taken by the TSO are based on the complex bids submitted initially at the DA stage and thereafter updated intraday. Complex Bids are translated by the TSO into Standard Products that can be used for trading balancing energy cross-border.

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

Figure 15 – Timing and direction of information flows in Gross Pool – Net Settlement Market option



9.4 ASSESSMENT OF THE GROSS-POOL NET SETTLEMENT

9.4.1 We now describe our qualitative assessment of the relative strengths and weaknesses of the Gross Pool Net Settlement Market against the HLD criteria. This assessment is done with consideration for this option on its own rather than comparatively against the other options for energy trading arrangements.

9.4.2 Ultimately, the performance of this option will be heavily influenced by the weight put on retaining some of the centralised features of the SEM, particularly of a gross mandatory ex-post pool with complex bids used in an integrated scheduling and dispatch process. This has been seen as positive in providing a route to market for a range of market participants, with transparency of market inputs and outcomes.

9.4.3 This would need to be considered against the impact of retaining a relatively high degree of regulation of behaviour of market participants (even if this may be less than today) alongside measures that might be needed to promote liquidity in the IDM and DAM to deliver efficient cross-border flows (which are determined outside of the pool).

9.4.4 In addition, more discussions may be needed at a European level around the implementation of a model compliant with the wording of the EU Target Model, but perhaps different to what has been implemented in Europe to date. This could include the possibility of the trades in the DAM and IDM becoming subject to regulation of financial (rather than energy) trading.

9.4.5 Table 8 summarises the initial qualitative assessment of the relative strengths and weaknesses of this option. In this table, the following colour-coding is used:

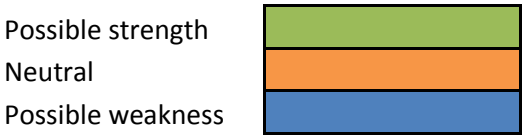


Table 8 – Summary assessment of the Gross Pool Net Settlement

SoS		Can be delivered by this option
Stability		Limited change from current arrangements
Efficiency		Can be delivered by this option
Practicality		Not a particular strength or weakness of this option
Equity		Pool provides route to markets, with greater targeting of costs and benefits
Competition		Strong regulation of market participant behaviour
Environment		Ex-post pool attractive for wind, but may need additional incentives for flexibility
Adaptive		Not a particular strength or weakness of this option
IEM		Compliant with requirements, but more unfamiliar model in European context

Security of supply: the chosen wholesale market design should facilitate the operation of the system that meets relevant security standards.

9.4.6 The discussion here is around the context in which security of supply would be delivered under this option, with respect to short-term issues (TSO actions, and interconnector flows) and longer-term issues (signals for long-term entry and exit).

9.4.7 The TSO processes to deliver a secure and safe system in this option are likely to be broadly similar to the current arrangements. The biggest difference is probably in relation to the scheduling of interconnector flows, which may be able to change much closer to real time than under current arrangements.

9.4.8 One of the possible issues for this option is that quality of the information that would be provided by market participants for the TSO's dispatch from the day-ahead stage which could affect the TSO's ability to manage operational security of supply. This will then determine the need for (continued) regulation of the commercial and technical offer data provided to the TSO at that stage.

9.4.9 One of the relative disadvantages of this option is that the interconnector flows would not be fully integrated into the pool process for dispatch (as they are inputs into the process rather than being determined within the pool itself).

9.4.10 In this option, there are two potential reference prices for supporting new entry to boost longer-term security of supply – the DAM and the ex-post pool. The quality of the DAM as a reference price will be driven by the liquidity of that market.

Stability: the trading arrangements should be stable and predictable throughout the lifetime of the market, for reasons of investor confidence and cost of capital considerations.

9.4.11 It will be important to get market participants' views in relation to this criterion as it specifically relates to their expectations of the regulatory process. The future existence and design of any CRM will also be an important aspect of stability, which is separate to the consideration of an individual energy trading option.

9.4.12 This option combines a pool-based approach for dispatch and ex-post pricing with voluntary financial ex-ante trading in forward timeframes, and in the European DAM and IDM (to determine physically scheduled flows).

9.4.13 The use of a pool-based approach allows the retention of complex bid structure for dispatch and ex-post pricing (but not in the European DAM and IDM) although market out-turns may be different depending on the arrangements put in place for recovery of start-up and no-load costs associated with complex bids.

9.4.14 In this option, there is somewhat of a disconnect between the physical flows on the interconnectors, which are determined by the European market coupling

arrangements, and the operation of the pool. This raises the question of whether the arrangements allow for interconnector flows to act as an effective alternative to starting plant in the SEM. If there is a large increase in interconnection, then this could become a more challenging issue requiring changes in market arrangements.

9.4.15 This option has the greatest reliance on financial trading as a hedging tool (outside of the pool), which means that this option could present the biggest risk in terms of exposure to possible changes in financial trading regulations with respect to the treatment of non-physical trades. For example, it would need to be determined whether the reporting (and licensing) requirements for all island market participants trading outside the pool would fall under financial regulation (such as MIFID II) rather than energy market regulation (such as REMIT).

Efficiency: market design should, in so far as it is practical to do so, result in the most economic (i.e. least cost) dispatch of available plant

9.4.16 In this option, dispatch is highly centralised as it is broadly in line with current arrangements in the SEM. Unit commitment and dispatch is based on complex bids submitted into a mandatory pool at the day-ahead stage, with subsequent updates.

9.4.17 Of particular relevance for the all island market in reaching an efficient dispatch position is the efficiency of the unit commitment process. In this option, the full (three part) complex bids currently used in the SEM are used for unit commitment.

9.4.18 One possible issue for this option with respect to the efficiency of dispatch is the liquidity of the DAM price based on voluntary trading, and the extent to which that provides an effective signal for demand side response to participate in the energy market.

Practicality/Cost: the cost of implementing and participating in the wholesale market arrangements should be minimised; and the market design should lend itself to an implementation that is well defined, timely and reasonably priced

9.4.19 The costs of implementation and participation need to be considered from the perspective of central systems and the direct costs to market participants.

9.4.20 In all of the options for energy trading arrangements, market participants are likely to require some new systems (or participate through an intermediary if this is possible) if they wish to participate in the European DAM and/or IDM. Similarly, central systems will need to be developed and/or procured to allow all island market participants to access the European markets.

9.4.21 However, the systems are similar to ones used in a number of other European markets so more standardised solutions may be available. For effective participation in a continuous IDM, 24 hour trading functionality is likely to be a requirement (which again could be delivered by an intermediary).

9.4.22 In this option, the ex-post pool provides market participants with a greater choice of whether or not to participate in the European markets. However, the costs of participation by all island market participants in the European markets in this option may be greater if that trading is deemed to be subject to financial trading regulations with respect to the treatment of non-physical trades. For example, it would need to be determined whether the reporting (and licensing) requirements for all island market participants trading outside the pool would fall under financial regulation (such as MIFID II) rather than energy market regulation (such as REMIT).

9.4.23 The data flows and pricing algorithm involved in the pool (used for ex-post pricing and dispatch) means that the ongoing costs for the pool are likely to be similar to current levels. However, there may be some changes required – e.g. more frequent rebidding, and more data to be provided by market participants to facilitate the net settlement process.

Equity: the market design should allocate the costs and benefits associated with the production, transportation and consumption of electricity in a fair and reasonable manner

9.4.24 There are two main aspects to the assessment of equity – the first is about the equality of access to different markets for a range of market participants, and the second is the delivery of an allocative efficient outcome where prices reflect marginal costs (including some allowance for the risk of provision where appropriate). Obviously, the energy trading arrangements are not the only determinant of equity – for example, other energy policies address the issue of including externalities (such as CO_2) in market prices.

9.4.25 In terms of access to the different energy markets, there remains an ex-post mandatory gross pool which provides a route to market open to all market participants, with limited advantage for portfolio players.

9.4.26 The access to the ex-ante markets will depend on the liquidity of the DAM and the IDM that emerge in this option. Liquidity will be helped by the fact that in this option, all physical interconnector capacity should be available for the DAM and IDM as FTRs rather than PTRs are used as long-term cross-border hedging tools. However, the attractiveness of the pool price may not encourage the development of liquid ex-ante trading. Furthermore, if market participants trading in the DAM and IDM are judged to be subject to the regulatory framework for financial trading, then this may provide some additional barriers to participation in the DAM and IDM.

9.4.27 The use of complex 3 part bids into the pool means that there will need to be a mechanism for the recovery of start and no-load costs. This can be done through uplift arrangements (to produce a single SMP covering SRMC, start and no-load costs) or through make-whole plants for individual units. Consideration would need to be given how this is addressed in the implementation of the pool in this option.

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

9.4.28 This option is designed to focus competition for physical volumes in the ex-post pool. This would provide a route to market (with a strong reference price) for independent and small generators or suppliers, similar to the arrangements in the current SEM. It is also important that stakeholders have confidence that the conditions are in place for effective competition (which helps to support efficient new entry for example). In this regard, the transparency of trading behaviour and outcomes has been seen as important in the SEM. The requirement for complex (unit-based) bids and mandatory participation in the pool means that there is a high transparency of bidding in this option, which would facilitate ex-post market monitoring.

9.4.29 The issue for this option is the extent to which the DAM and IDM will be sufficiently liquid to support effective competition – this will be supported by the availability of interconnector capacity in these markets, but may be discouraged by the emphasis on the ex-post pool as the main market.

Environmental: while a market cannot be designed specifically around renewable generation, the selected wholesale market design should promote renewable energy sources and facilitate government targets for renewables.

9.4.30 In general, the use of a pool to determine the ex-post price has been seen as positive for intermittent generation sources such as wind. This is because the price formation in the pool (based on out-turn availability) shields the wind generation from the impact of it being less predictable closer to real time (and effectively socialising the energy balancing costs across all market participants). The pool can also provide a commercial benefit for plant with priority dispatch status as they can be regarded as price-takers in the pool.

9.4.31 However, the converse of this is that the wind does not face commercial incentives from the market to increase its predictability closer to real time (e.g. through more accurate forecasts), and that the flexible resource required to manage the variations in wind output do not receive the full value of this flexibility (in the pool price).

9.4.32 This means that separate mechanisms (outside or on top of the energy trading arrangements) may need to be put in place to incentivise the delivery of the flexibility (e.g. within-day) required to help the system accommodate higher levels of wind.

9.4.33 In this option, there is scope for flexible resources to benefit from intraday prices. The issue is whether wind will be sufficiently encouraged to trade in the intraday market (with no guarantee of physical volumes) for the value of within-day flexibility to be revealed, particularly given the relative attractiveness of the ex-post pool price for wind.

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

9.4.34 The governance arrangements for any set of trading arrangements tend to be determined at the implementation stage, i.e. a level of detail below the HLD. Therefore, adaptability is typically not a major distinguishing feature of different energy trading arrangements.

9.4.35 In this option, the retention of a gross mandatory pool may be easier to make all island specific changes to the arrangements (whilst still needing to comply with the requirements of the European Network Codes, particular in relation to Electricity Balancing). However, it may be harder to coordinate these changes with developments across Europe

The Internal Electricity Market: the market design should efficiently implement the EU Target Model and ensure efficient cross border trade

9.4.36 The February 2013 Next Steps Decision Paper stated that the revised HLD must be able to comply fully and efficiently with the specifications set out in the following five pillars of the EU Target Model[36]:

- **Capacity Calculation and Zones Delimitation** – option is compatible with requirements, and could work with a number of zones;
- **Cross Border Forward Hedging and Harmonisation of Capacity Allocation Rules** – the option uses PTRs, which are allowed under the Forward Capacity Allocation Network Code, with the rules and processes for allocation to be confirmed as part of the implementation and ongoing operation of the revised HLDs;
- **Day Ahead Market Coupling** – complies with the requirement for a single day-ahead price coupling;
- **Intra Day Continuous Trading** – could comply with the requirement for continuous implicit allocation of cross-zonal capacity, and could support periodic auctions alongside the continuous trading); and
- **Cross Border Balancing** – this option is expected to use the Integrated Scheduling and Dispatch provisions included in the Electricity Balancing Network Code for markets designated as central dispatch (e.g. allowing the TSO to convert pool bids to/from Standard Products).

9.4.37 The efficiency of cross-border trade in this option will depend on the liquidity of the DAM and IDM, which is driven by the amount of financial trading outside the pool.This option uses the Integrated Scheduling and Dispatch provisions included in the Electricity Balancing Network Code for markets designated as central dispatch. There are still some uncertainties to be resolved at a European level as to how these provisions would interact with the requirements of other EU Target Model Network

[36] Section 11 contains a list of documents that can provide further details on the EU Target Model.

Codes, in particular the CACM Network Code and the requirements for continuous intraday trading.

9.4.38 In the Gross Pool Net Settlement, the matched trades in the day-ahead and intraday European coupling arrangements, while being financially firm are not 'physically firm' for all island market participants (i.e. cannot be used to support physical nominations of production or consumption to the TSO for its use in dispatch). They however do produce 'physical' cross-zonal flows which are nominated to the TSO by the shipper, which appears to be consistent with the wording in the current drafts of the CACM Network Code.

9.4.39 While financial spot trades of this nature may be unusual in the European context[37], they are used in other electricity markets, such as can be found in the USA/ However, it is our understanding that using 'financial' instruments to determine cross-border flows [38] would be a first, certainly for Europe as market splitting/coupling has historically been carried out by spot exchanges or spot market operators (NordPool Spot first, then EPEX Spot, Belpex, APX, OMEL, GME, which are all physical exchanges proposing physical contracts.).

9.4.40 This may require a greater level of discussion with European stakeholders over the operation of the proposed arrangements for trading in the DAM and the IDM as these arrangements will be less familiar in the context of European market integration. The questions that may be raised include:

- How would stakeholders in Great Britain respond to cross-zonal capacity being allocated through physical trades on one side of the interconnector (GB) and financial trades on the other side?
- Would this option increase the likelihood that European and/or national financial regulations would apply to any market participants in the day-ahead and intraday markets, as well as the power exchange, and shipping agent?

In addition, we consider any problems for the options in relation to complying with the European requirement for the implementation of the new HLD by 1 January 2017. Although this option will require significant new systems to support participation in European DAM and IDM, these already exist in a number of other European markets, which means that they could be effectively 'bought off the shelf'. In addition, there would likely be changes to existing SEM systems (which will have been in place for nine years by 2016) which would need to be completed during the implementation phase.

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37 One example of an instrument that could be close to this kind of instrument are Daily Futures. EEX Power Derivatives, a derivatives market) currently makes available for trading daily Futures for power in Germany, which are contracts for baseload and peakload with cash-settlement against the day-ahead (physical) index (Phelix) for baseload and peakload. They differ from the proposed option because they are quoted by a financial institution rather than a power exchange, do not provide hourly prices, and are not used to allocate XB capacity.

38 Other financial instruments are allowed under the EU Target Model in relation to cross-border risk hedging – e.g. FTRs and CfDs – but these do not determine the physical flow on the interconnectors.

10 CAPACITY REMUNERATION MECHANISMS

10.1 CONSULTATION QUESTIONS

10.1.1 The following consultation questions relate to the issues discussed in this section:

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

20. Are any of the topics discussed in Chapter 10 more important than others in describing the high level design of any future CRM for the I-SEM?

10.2 OVERVIEW

10.2.1 In the February 2013 Next Steps Decision Paper, the SEM Committee reiterated the importance of total remuneration from energy payments, capacity payments and ancillary services being sufficient to ensure security of supply.

10.2.2 However, at this stage, the CRMs are presented independently of the four HLD options for energy trading arrangements. We believe that if assessed as being required, each of the CRM options presented in this section could be implemented alongside any of the energy trading arrangements.

10.2.3 In 2011 the RAs undertook a Medium Term Review of the CRM to analyse whether the CRM was still needed, and whether the objectives of the CRM remained the same[39]. The review concluded that the CRM remained important to the SEM because of its impact on the financeability of generation projects. It was also acknowledged that the CRM had been broadly successful in meeting its objectives. As such the SEM Committee was of the opinion that a CRM should remain in place as part of the design changes to the SEM.

10.2.4 The current SEM CRM allows for capacity remuneration for all cross border flows (including capacity charges for exports) payable on a €/MWh basis. However these current arrangements would not work unaltered under the market coupling proposed as part of the EU Target Model, because the capacity price is not finally fixed until after real-time.

10.2.5 To include the capacity price in market coupling would require the capacity prices to be known ex ante (for cross-border trading) which is not consistent with the calculation of an ex-ante pot that is rigidly adhered to.

[39] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=5ce2db5f-6c79-4454-9779-53dd7fae8dba

10.2.6 Given the potential changes to the energy trading arrangements, the developments in system services procurement, and the incompatibility of the current SEM CRM with market coupling, it now seems appropriate to review the form and scope of any CRM that will form part of the new HLD.

10.2.7 The Draft Decision Paper will present recommendations for any CRM that is proposed to be included alongside the energy trading arrangements. If any CRM is proposed for inclusion, then it will need to be compatible with the requirements of the European Commission guidance on State Aid in relation to generation adequacy.

10.2.8 A revised CRM in Ireland and Northern Ireland must be very closely interlinked with changes to the energy market and the ancillary services framework in order to reward flexibility and maintain an effective long term adequate capacity balance (while avoiding double payments for the provision of capacity).

10.3 REMUNERATION OF CAPACITY IN ENERGY-ONLY MARKETS

10.3.1 In energy-only markets, capacity costs are recovered through the energy trading arrangements. High spot prices (potentially as high as the value of lost load (VoLL) to consumers) are used to reward resources that are able to help balance supply and demand at times of system stress.

10.3.2 Ultimately, this approach relies on providers of capacity having enough confidence when making (dis)investment decisions about their ability to capture sufficient value of scarcity from spot energy prices, forward contracting (for either firm energy, reserves or energy options) or through a retail customer base. Therefore, allowing the price to properly reflect the value of scarcity is critical in an energy-only market.

10.3.3 There are some challenges in ensuring adequate remuneration for capacity in an energy only market:

- Indivisibility of plant size, particularly in a relatively small system where the capacity margin/deficit can be sensitive to a small number of investment decisions.
- Risk of intervention by central agencies whether political, regulatory or by the TSO that acts to dampen the high energy prices needed in periods of scarcity to provide incentives for new investment. For example, there may be a regulatory risk that a cap would be introduced if prices spiked to significant levels. Where this threat of intervention exists, the level of remuneration for investment may be insufficient. This is often referred to as the 'missing money' problem.
- Insufficient commercial incentives on market participants to balance their own supply-demand position. This means the market does not address the

fact that reliability is a quasi-public good. It is non-excludable in the sense that customers cannot choose their desired level of reliability, since the system operator cannot selectively disconnect customers.

- Demand side participation may not be sufficiently strong – although we note the Demand Side Vision set out by the RAs and the planned roll-out of smart meters across Northern Ireland and Ireland.
- Inability of market participants to find long-term hedges for the price and volume risk in short-term markets, which could increase the cost of capital of investment in capacity. This may be exacerbated by increased RES penetration further reducing the number and predictability of operating hours of thermal plant which can increase revenue volatility (as highlighted by the European Commission[40]).

10.3.4 One possible policy option for addressing these challenges is the implementation of a CRM to support capacity adequacy. There can also be challenges in the effective implementation of a CRM, including:

- CRMs may be a response to existing market distortions such as price caps (either explicit or implied through the threat of regulatory intervention);
- the need to distinguish between missing money and missing capacity;
- market wide capacity mechanisms can over reward generation which was already financially viable;
- establishing the correct value for capacity remuneration is difficult and may be open to accusations of political interference;
- that it cannot be assured that the required capacity will be delivered (particularly given regulatory uncertainty associated with the setting of the payment);
- risk of distortion to trading, production and investment decisions in the internal electricity market; and
- possible discouragement of innovative solutions, such as DSR based on high wholesale prices (particularly if the DSR is not eligible for the capacity mechanism).

10.3.5 Therefore, it is also worth considering the scope for contribution of other possible ways of trying to address the challenges posed by an energy-only market. These include encouraging active demand side participation, increased interconnection and addressing wider market failures, which should all lead to a reduction in the risk of 'missing money', and could work alongside a CRM. In addition to the factors listed above, the decision on the appropriate policy mix will depend on a range of factors, such as the realistic scope for demand side participation, the

40 http://ec.europa.eu/energy/gas_electricity/internal_market_en.htm

opportunities and costs of interconnection, the ability to address wider market failures etc.

10.4 DRAFT EU GUIDANCE ON GENERATION ADEQUACY AND STATE AID

10.4.1 CRMs are now the subject of review at European level, although as it stands, the EU Target Model neither requires (nor prohibits) a CRM from being put in place. The European Commission has published draft guidance on Capacity Remuneration[41], and is currently consulting on the draft State Aid Guidelines[42] currently being consulted on by the European Commission.

10.4.2 These documents present a (non-binding) framework for assessing and delivering the appropriate solution for generation adequacy concerns. Any CRM developed for the new HLD should be compatible with these guidelines.

10.4.3 The EC's State Aid consultation provides (draft) guidance on what the most appropriate solution/option should look like. The guidance is designed to help regulators avoid creating distortions in the energy market, and includes:

- avoiding distortions of cross-border trade, i.e. no reservation of national generation for national demand, no export restrictions, no price caps and no bidding restrictions;
- cross-border participation;
- technologically neutral and fit into the decarbonisation agenda;
- transparent and non-discriminatory allocation of costs;
- time-limited intervention.

41 http://ec.europa.eu/energy/gas_electricity/internal_market_en.htm

42 http://ec.europa.eu/competition/consultations/2013_state_aid_environment/index_en.html

10.5 TOPICS FOR THE CRMS

10.5.1 This section differentiates between different CRM designs with respect to the core features. These core design topics include:

- Scope of the CRM
- Nature of the incentive
- Timings and distribution of the CRM
- Eligibility
- Level of intervention

10.5.2 Table ***9*** lists the main topics (and associated sub-topics) for describing how each CRM is designed. In the rest of this section, we describe these topics and sub-topics in more detail.

Table 9 – Topics for the CRMs

Topics	Sub topics
Scope of the CRM	Market wide or targeted scheme?
Nature of the incentive	Is the CRM price or quantity based?
Timings and distribution of the CRM	Forward visibility of the price signal Timing of certainty Timing of commitment Is re-trading of capacity possible? Granularity of payments
Level of intervention	Price quantity target setting Penalty arrangements Procurement of capacity
Eligibility for the CRM	Will CRM payments be linked to participation in a particular energy market? Inclusion of CRM price in Market Coupling Cross border participation in the CRM

SCOPE OF THE CRM

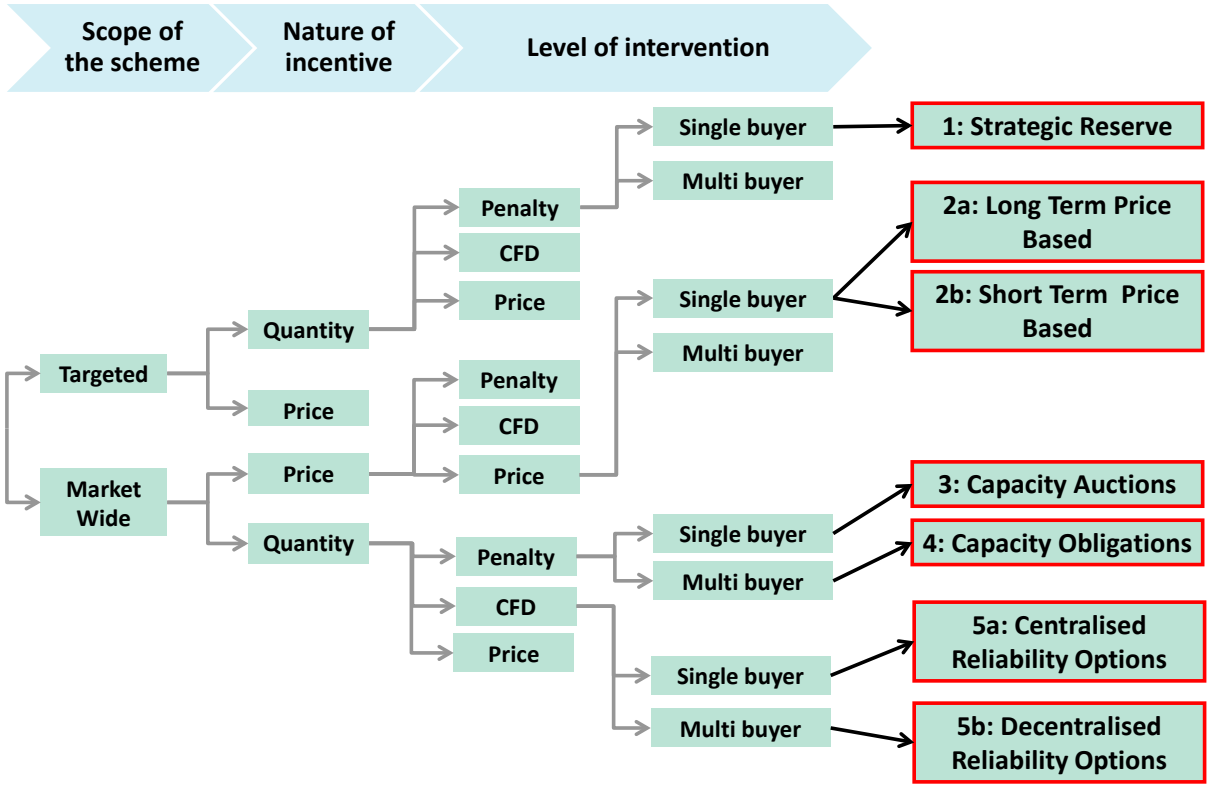
10.5.3 When considering the possible scope for a CRM, there are two different aspects to consider: Targeted mechanism; and/or Market-wide mechanism.

10.5.4 Targeted mechanisms should be used to address specific issues relating to capacity adequacy (e.g. targeted at a location or to deliver a certain type of generation such as flexibility). For this reason we consider strategic reserve as the representative 'targeted' mechanism, in which the consequences of the capacity trades on the wider energy market are limited.

10.5.5 Market-wide mechanisms deliver capacity from generation and demand which is also free to participate in the energy trading arrangements. Market wide mechanisms may still differentiate between different providers based on their reliability e.g. less reliable plant might receive lower [quantity] credits.

10.5.6 An overview of the scope of CRMs is provided in Figure 16 below:

Figure 16 – Capacity Remuneration Mechanisms



NATURE OF INCENTIVE

10.5.7 At a high level there are two broad incentives to facilitate the recovery of capacity costs by resources participating in the energy trading arrangements (market wide as opposed to targeted schemes)[43]. These are:

- Price-based CRM:
  - in which an administered payment is calculated with the aim of achieving a certain reliability level;
  - out-turn quantities are dependent on the behaviour of market participants in response to the administered prices);
- Quantity-based CRM:
  - in which a required quantity is calculated and contracted to achieve a given reliability level
  - out-turn prices are dependent on the behaviour of market participants
  - the contracting can be centralised or decentralised and can take various forms (*inter alia* capacity auctions, capacity obligations or reliability options).

[43] This is not always the case as the tendering process can lead to capacity which then sells energy

PRICE BASED CRM

10.5.8 The current CRM in the SEM is an example of a price-based CRM. It provides a separate revenue stream for capacity providers (in this instance without commitment on the part of the provider) that supplements any infra-marginal rent earned from the energy market.

10.5.9 In a price based CRM, a value is attached to capacity and included as an explicit element of the price paid to available generation/demand resources.

10.5.10 In theory an explicit capacity price signals the need for existing plant to remain on the system and/or for additional capacity to be developed. However this will again depend on the intent of the scheme. For example what type of capacity is required?

10.5.11 This provides reasonable expectation of cost recovery for efficient new generation (to supplement infra-marginal rent earned from energy market) or demand side provision of capacity. Although the extent of this signal will depend on the design of the scheme which could be targeted at long or short term.

QUANTITY BASED CRM

10.5.12 This document presents three types of quantity-based CRM that can be used to reward capacity participating in the energy trading arrangements. These are Capacity Auctions, Capacity Obligations, and Reliability Options (two variants).

10.5.13 The quantity based schemes place an obligation on the participant to ensure adequate capacity is delivered.

10.5.14 In theory in order to meet an obligation, a party will commit existing capacity to remain on the system and encourage additional capacity to be developed. This provides a stable environment for delivery of efficient new capacity.

TIMINGS AND DISTRIBUTION OF THE CRM PAYMENTS

10.5.15 This topic covers the arrangements for the timings and distribution of the CRM payments. This includes an assessment of the visibility of the price signal, certainty of the price signal, timing of commitment, granularity of the payments and the ability to re-trade committed capacity.

FORWARD VISIBILITY OF THE PRICE SIGNAL

10.5.16 The forward visibility of the CRM price signal provides information to market participants on the requirement of capacity in the market. This signal can vary in length depending on the intent of the scheme. For example in the proposed French CRM capacity requirement will be secured 4-5 years ahead of the delivery year. The philosophy of the existing CRM within the SEM is to reward capacity as

if the system were in long term equilibrium (such that the combination of SMP and the capacity payment sets prices at Long-Run Marginal Cost (LRMC)), with no sharp reduction in the capacity pot in years with significant overcapacity. Conversely the CRM in the original England and Wales Pool provided a half-hourly price (set day-ahead) based on the expected system margin, with very significant volatility day-on-day and year-on-year.

TIMING OF PRICE CERTAINTY

10.5.17 Price certainty will usually be determined centrally by the regulatory authorities and can be set for any period of time.

TIMING OF COMMITMENT

10.5.18 The timing of commitment determines at what point participants operating in the CRM are contractually bound to the delivery of the capacity (if at all). There are no limitations on the commitment and it can range from no contractual commitment (such as in the price based CRMs like that in the SEM) to any specified period (such as timescales defined by periods of system stress).

GRANULARITY OF PAYMENTS

10.5.19 The granularity or distribution of the CRM payments is essential to adequately reflect the differing value of capacity through the day, week and season. For example in the SEM the distribution is a 30%, 40% and 30% ratio of respectively the Fixed Ex-ante, Variable Ex-Ante and Variable Ex-Post weighting components, with further smoothing resulting from the creation of annual and monthly payment 'pots'.

10.5.20 The distribution will depend on the intent of the CRM. For example the current CRM in the SEM was intended to '*encourage the construction and maintenance of available capacity. Additionally, it should encourage short-term availability when required and efficient outage scheduling*'.

10.5.21 The distribution allows for a balance between a short term signal to provide the required capacity during periods of tight capacity margin, and the longer term certainty over capacity revenues for generators[44].

RE-TRADING OF CAPACITY

10.5.22 Re-trading of capacity will allow participants to unwind a commitment made to deliver a predetermined level of capacity. Again this is only relevant for those CRM options where a firm contract of commitment has been agreed by the participant for delivery of capacity.

[44] http://www.allislandproject.org/GetAttachment.aspx?id=2d5ffe11-be31-4c46-bdd1-1f98aacbcd66

10.5.23 Re-trading of capacity may be necessary on occasions where a participant is unable to deliver the necessary capacity requirement.

LEVEL OF INTERVENTION

10.5.24 This topic is concerned with the level of centralisation within the design of the CRM. This includes administrative decisions on setting the price / quantity targets, procurement of capacity, and penalty arrangements.

10.5.25 The level of centralisation will have an impact on the level of regulatory involvement in the CRM, which will impact on the level of investment certainty for participants.

SETTING PRICE AND QUANTITY TARGETS

10.5.26 In most CRMs the price or quantity targets will be defined centrally by the RAs with advice from the TSO. This is in line with the draft guidance set out by the EU Commission which states that the requirement or need for a CRM should be developed and presented by the national TSO in the first instance. EirGrid/SONI currently produces the Generation Adequacy Report for the All-Island market.

DETERMINATION OF PENALTY

10.5.27 Penalty arrangements are only relevant for schemes in which an obligation is placed on the participant to deliver physical energy (i.e. not the price-based schemes). In price-based schemes a value is attached to capacity and paid to available generation/demand resources and as such no ex-ante contract has been struck by the participant. As a result in a price-based scheme the penalty is that you forego the payment; as opposed to the prospect of receiving one payment and making a separate penalty payment for non-delivery.

10.5.28 Penalty arrangements, where applied, can be determined centrally by the regulator or through a market based contractual approach.

PROCUREMENT OF CAPACITY

10.5.29 Procurement of capacity can either be centralised or decentralised, as in the quantity obligation CRM schemes. This decision should be based on who is best placed to determine the capacity requirements.

10.5.30 Under most CRM designs the TSO is given the obligation to procure the capacity from market participants in a centralised approach. However CRMs exist, such as in the proposed French CRM, where the obligation is placed on the market participants (e.g., suppliers) to purchase a level of capacity based on their contribution to peak demand.

ELIGIBILITY FOR THE CRMS

10.5.31 This topic covers the requirement or not of capacity providers to be operate in a particular market. Separately it also considers the interaction of the CRM with market coupling, relating to whether the CRM price can be included within the market coupling price, and separately whether the CRM scheme will allow cross border participation.

REQUIREMENT FOR PARTICIPATION IN A SPECIFIC ENERGY MARKET

10.5.32 The interaction between the capacity arrangements (targeted or otherwise) and the energy markets (from forward to real time) varies. With some schemes the nature of participation in the energy market is prescribed, whereas with others the effect is indirect through the impact of the capacity revenue on decisions on new entry, plant closure and demand side action.

10.5.33 The requirement or otherwise of market participants to operate in a particular market (day-ahead, intraday and balancing markets) in order to receive capacity payments will differ according to the design of the CRM. For example:

- **Strategic reserve**: obligation not to participate in energy or balancing markets (at least below a high administered price floor)
- **Broad based capacity payment (price or quantity based)**: no specific obligation other than to be available. This type of might remove the need for new entrant capital costs to be recovered from energy markets, damping peak prices to some unspecified extent. This may lead to the recovery of less scarcity rent by other plants outside this mechanism.
- **CfD/reliability option**: no direct obligation other than financial. However a large quantity of contracted capacity with a common strike price may mean that price could become a *de facto* price cap.

10.5.34 Under the SEM, the relationship between the energy market and the capacity market is formalised through the eligibility requirement that capacity must be available until the time of delivery and the licence requirement that energy bids must be in line with short run marginal costs.

INCLUSION OF CRM PRICE IN MARKET COUPLING

10.5.35 This determines whether the CRM price can be included within the market coupling price across the different market timescales. For example if the capacity price is known ex ante (rather than partially ex post as now in the SEM) market participants would be able to include the expectation of the CRM price in their Euphemia bids.

CROSS BORDER PARTICIPATION IN THE CRM

10.5.36 This determines whether cross border trades are eligible for capacity remuneration. This requirement is set out in the EU Commission draft guidance

on Capacity Remuneration and in the draft State Aid Guidelines currently being consulted on by European Commission. This guidance states that CRMs should allow cross border participation via interconnector capacity (but avoiding double payments).

10.5.37 To be compliant with the EU Target Model the SEM CRM would have to be set ex ante (rather than partially ex post as now) and the coupling algorithm would have to take account of the ex-ante price to ensure efficient trades, much as it should allow for technical losses on DC interconnectors

10.6 SUMMARY DESCRIPTION OF THE CRM OPTIONS

10.6.1 This section presents the following options for the CRM:

1. Strategic Reserve
2. Price based CRM (two variants)
   - Long term Price based CRM
   - Short term Price based CRM
3. Quantity based Capacity Auction
4. Quantity based Capacity Obligation
5. Quantity based Reliability Option (two variants)
   - Quantity based Reliability Options Centralised
   - Quantity based Reliability Option Decentralised

10.6.2 Table 10 describes each CRM option based on the topics discussed in Section 10.5.

Table 10 – Overview of CRM options

			Market Wide Price based CRM		Market Wide Quantity based CRM			
		Strategic Reserve	**Long term CRM**	**Short term CRM**	**Capacity Auctions**	**Capacity Obligations**	**Centralised Reliability Options**	**Decentralised Reliability Options**
Scope		Targeted	Market Wide	Market Wide	Market Wide	Market Wide	Market Wide	Market wide
Price vs. Quantity		Quantity	Price	Price	Quantity	Quantity	Quantity	Quantity with 'user-defined' prices
Timing	**Forward visibility of price signal**	Long term	Extra Long term	Short term	Both (Long term with short term penalty)	Both (Long term with short term penalty)	Long term	Both (values short term and trade forward to hedge)
	Timing of certainty (x is lead time of reward)	Y-x	Y- x	DA or ID (LOLP VoLL)	Y-x	Y-1 (bilaterally trade available)	Y-x	Y-x
	Timing of commitment	Y-x	None	None	Y-x	Y-1	Y-x	Y-x
	Granularity	Y and M	Y, M and HH	M and HH	Y, M (HH penalty)	Y, M (HH penalty)	M (at HH)	M (at HH)
	Re-trading	No	No	No	Yes	Yes	Yes	Yes
Level of intervention	**Price quantity target setting**	Centralised						
	Penalty arrangements	Centralised at VoLL	None	None	Centralised at VoLL	Centralised at VoLL	Market-based (e.g. Ex-post or DAM price)	Market-based (e.g. Ex-post or DAM price)
	Procurement of capacity	Centralised	Centralised	Centralised	Centralised	Decentralised	Centralised	Decentralised
Eligibility	**Which market?**	Participation in the BM (or ex-post pool) only	Actual outturn availability	Actual availability or unscheduled available capacity.	Must be physically delivering energy at the 'critical point' (loss of load) or face penalty	Obligation of physically delivering energy at the 'critical point' (loss of load)	No physical obligation, financial incentive	No physical obligation, financial incentive
	Inclusion of CRM price in Market Coupling	No	Yes	Yes	No	No	Yes	Yes
	Cross border participation	No	Yes	Yes	No (but could be developed)	No (but could be developed)	No (but could be developed)	No (but could be developed)

10.7 OPTION 1: STRATEGIC RESERVE

CONSULTATION QUESTIONS

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

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

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

DESCRIPTION

10.7.1 Strategic Reserve is a targeted scheme, implemented to address issues where certain types of capacity are not adequately rewarded through the energy trading arrangements. It is typically intended to help the TSO by providing capacity with specific characteristics in terms of location of generation or capability requirements.

10.7.2 Apart from cases where the economic signals from the energy trading arrangements fail to deliver specific types of capacity, Strategic Reserve can also be used to deliver capacity in cases where there is a need beyond the security of supply standard as dictated by economic signals (for example where there is political desire for enhanced security of supply).

10.7.3 In general, Strategic Reserve capacity is kept separate from the energy market to try to minimise its impact on wholesale energy prices, and avoid undermining the incentives for new entry in the wholesale electricity market. It can be dispatched at a price at (or close to) the Value of Loss of Load (VoLL) only in the Balancing Mechanism (or in the ex-post pool depending on the energy trading arrangements).

10.7.4 Strategic Reserve can also be used in tandem with any of the market wide CRMs presented in this section. For the purpose of this paper however we do consider Strategic Reserve in isolation.

ASSESSMENT

10.7.5 Strategic Reserve, being by nature a form of targeted intervention, supports capacity with specific characteristics and can deal with issues not restricted only to capacity adequacy. As already stated, these include delivering capacity at specific locations as well as capacity with certain flexibility characteristics. At the same time, this does, however, mean that there is greater discretion from a

centralised agency (typically the TSO) on deciding the nature and type of supported capacity.

10.7.6 Strategic Reserve is not intended to provide long term investor certainty on a market-wide basis – instead new entry is expected to be driven by price signals in the energy market. Therefore, Strategic Reserve capacity is ring-fenced from the market so that it does not distort short-term energy prices. As a consequence, this should help to facilitate demand side participation and there is no distortion of cross border trade even in the case where different security standards are considered for different zones.

10.7.7 Strategic Reserve is highly centralised, and typically involves a regulated approach to determining capacity targets, relevant penalties and the procurement process (although competitive tendering can be used). It is therefore important to establish confidence and not allow for relaxation of the penalty pricing or growth of the capacity targets.

10.7.8 Changes to the Strategic Reserve parameters could result in the mechanism interfering with the energy market and becoming the 'market' for new entry. This is, in academic circles, called the 'slippery slope syndrome'.

10.8 OPTION 2: PRICE-BASED CRM

10.8.1 The current CRM in the SEM is an example of a price-based CRM. It provides a separate revenue stream for capacity providers that supplements any infra-marginal rent earned from the energy market. Similarly, energy buyers pay an additional charge on top of their payments in the energy market.

10.8.2 It typically involves a regulated approach for determining the capacity price in each settlement period or an annual capacity payment pot. There are then different approaches for determining the profile of the capacity price over different settlement periods. The price profile is intended to reward capacity that is available to the system over periods of scarcity.

10.8.3 We present two different variants of price-based CRMs, which explore the difference between providing a long-term price signal to support capacity, and providing a short-term price signal that is very responsive to system conditions on the day.

10.9 OPTION 2A: LONG-TERM PRICE-BASED CRM

CONSULTATION QUESTIONS

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

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

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

DESCRIPTION

10.9.1 This option retains the long-term price signal provided by the CRM in the SEM. Of course, the strength of the long-term signal will be influenced by the extent to which market participants expect the scheme to continue in the long-term.

10.9.2 In this scheme, an annual pot for capacity payments is calculated centrally according to an agreed formula. This annual pot is in turn split into monthly pots at the beginning of each year based on an expectation of system tightness over each month. Then, within each month, there is an ex-ante calculation of the capacity payment in each settlement period based on an expectation of system tightness within that month.

10.9.3 Both available capacity (whether scheduled or not) and demand receive and pay the same capacity payment. This means that the overall cash flow is unbalanced as volume of available capacity will exceed the level of demand. Therefore, a mechanism will need to be in place to recover from end-users the cost of capacity payments made to unscheduled available capacity.

10.9.4 If the ex-ante capacity price is added to bids into the DAM, then this will effectively allow capacity in other countries to access the scheme through the market coupling process (subject to there being sufficient available cross-zonal capacity). Exports will also pay the same capacity price as domestic demand through its inclusion in the market coupling process.

10.9.5 This total resulting payments to all available capacity in any month may not equal the initial monthly pot as there will be a deviation between forecasted available and resulting available capacity as well as forecasted demand and actual demand. Therefore, a mechanism will need to be put in place to deal with under/over

recovery – this cannot be done by having an ex-post element in the price, as this would distort cross-border flows.

ASSESSMENT

10.9.6 A long-term price-based CRM is designed to provide greater year-on-year stability in the capacity payment revenue stream, which in turn provides greater investor certainty. Such a scheme would be broadly familiar to the SEM market participants as it shares commonalities with the current CRM scheme. In this case, however, there is no ex-post reconciliation part in the payments as capacity payments are defined ex-ante in order to be compatible with market coupling.

10.9.7 The relative certainty of the annual pot comes however at the expense of stronger short-term price signals. The use of forecasting at the month-ahead stage means that that typically capacity payments will be damped and will not necessarily reflect actual system scarcity on the day. Consequently, the scheme may provide relatively greater benefits to more 'inflexible' and base load plant than flexible resources (e.g. generation, storage, demand side or interconnection).

10.10 OPTION 2B: SHORT-TERM PRICE-BASED CRM

CONSULTATION QUESTIONS

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

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

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

DESCRIPTION

10.10.1 This alternative price-based CRM places greater importance on short-term price signals at the expense however of long-term certainty.

10.10.2 Under this model, capacity prices are determined based on a regulated scarcity rent function with the capacity price being fully responsive to the capacity margin. The capacity price will be determined initially at the DA stage and thereafter updated periodically to reflect changes in available capacity, demand and wind forecast as new information becomes available. The final calculation of the capacity price is carried out ex-post based on actual available capacity and demand.

10.10.3 Capacity payments are included in the bids in the ex-ante timeframes both in the DA market coupling and the ID cross border trading. This can be carried out either directly by a central agency or indirectly by market participants.

10.10.4 Both available capacity (whether scheduled or not) and demand receive and pay the same capacity payment at any particular point in time. This means that the overall cash flow is unbalanced as volume of available capacity will exceed the level of demand. Therefore, a mechanism will need to be in place to recover from end-users the cost of capacity payments made to unscheduled available capacity.

10.10.5 If the ex-ante capacity price is added to bids into DAM (and into the IDM), then this will effectively allow capacity in other countries to access the scheme through the market coupling process (subject to there being sufficient available cross-zonal capacity). Exports will also pay the same capacity price as domestic demand through its inclusion in the market coupling process.

ASSESSMENT

10.10.6 This short-term price-based CRM provides strong incentives for capacity providers to be available at times of scarcity (and for demand to reduce consumption at such times, as they would avoid the capacity payment). There is however a trade-off with lower long-term investor certainty when compared to the long-term price-based CRM, because annual revenue will be more uncertain.

10.10.7 The efficient short-term price signals are more favourable for flexible resources (including interconnection) than base load providers. However, this is done by using the short-term price volatility that some other CRMs are trying to dampen.

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

10.11 OPTION 3: QUANTITY BASED CAPACITY AUCTION

CONSULTATION QUESTIONS

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

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

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

DESCRIPTION

10.11.1 A centralised Capacity Auction scheme, such as the scheme being introduced in Great Britain, aims at ensuring sufficient capacity and a relatively stable environment for capacity investment.

10.11.2 A central agency sets a required capacity requirement for a defined period of time, based on an assessment of generation adequacy. This central agency could be the TSO or the RA based on a recommendation by the TSO. Procurement of capacity is carried out through a centrally organised auction. Both generating units and other types of capacity (storage, demand etc.) can participate with the capacity price being the resulting clearing price of the auction.

10.11.3 All capacity procured in the auction receives an annual payment (based on the clearing price in the auction). The auction typically takes the form of a 'descending clock' auction potentially consisting of several rounds. This involves capacity providers confirming they will provide a certain amount of capacity at a certain price. In the first round the price is set at the price cap. In every subsequent round the price is decreased in decrements until the auction discovers the minimum price that delivers sufficient capacity.

10.11.4 Capacity requirements for each delivery year will be secured through an auction up to a certain number of years ahead (for example > 3 years) – the lead time should be sufficient to allow new capacity build where required. This can be supplemented by a further auction closer to delivery year (say 1 year ahead) auction to allow demand side participation and fine tuning.

10.11.5 This approach provides a long-term price signal and certainty to participants, as well as opportunity for procuring 'capacity' from the demand side on an annual basis. There can also be provisions for re-trading.

10.11.6 By receiving the capacity payment, the capacity providers now have a responsibility to deliver capacity over system stress periods (however that is defined). This responsibility is enforced by penalty arrangements that would apply in the case of non-delivery. The penalty payment can be set to as high as VoLL. The specific design of the penalty arrangements is a defining element for the attractiveness of such a scheme to providers as it will determine the risk that they take on by participating in the scheme.

10.11.7 Capacity auctions are market-wide in principle. However, there could be specific provisions on technical characteristics (especially in terms of capability) in the type of generation and demand that can partake in the capacity auction. Also, some technologies may be less able to manage the delivery risk and hence may not participate in the auctions.

10.11.8 This option potentially allows for cross border participation in the scheme – however, it requires rules to be clarified about the volume of out of zone capacity that is eligible (normally up to interconnection capacity) and the requirement for delivery by the out of zone capacity.

10.11.9 There are two broad choices – delivery may be required into the All-Island Market, or the generator must simply deliver into their local market. The complicating factor is that under the EU Target Model, out of zone capacity will not be able to specify the direction of flow of the interconnector after the start of the market coupling processes in day-ahead and intraday. Therefore, if the out of zone capacity is required to deliver to the All-Island Market to avoid the penalty, it may not participate in the scheme as it cannot manage the risk of non-delivery.

ASSESSMENT

10.11.10 A quantity-based capacity auction is a market-based mechanism for delivering sufficient capacity that provides a transparent price for capacity.

10.11.11 It provides a relatively stable environment for capacity investment through a multi-year capacity requirement. This could potentially mean lower regulatory uncertainty and risk for market participants. This lower regulatory risk can however be offset through the penalty arrangements.

10.11.12 There is reasonable certainty to policy makers that the required capacity will be delivered. Whether that capacity will be available when required at short notice relies on the exact mechanics of the penalty arrangements that will act as an incentive for market participants to deliver at critical times within certain time limitations. Indeed, the key factors that determine the relative attractiveness of this scheme for capacity providers are the definition of periods of system stress and the penalty for non-delivery of capacity at those periods.

10.11.13 Unlike the price-based CRM schemes, Capacity Auctions do not offer a short-term capacity price signal and can actually dampen energy prices, which can lead to

inefficient signals to flexible providers (such as the demand side and interconnection, who can respond to those signals).

10.11.14 In addition, market power mitigation measures may be needed to facilitate a competitive outcome from the auction process.

10.12 OPTION 4: QUANTITY BASED CAPACITY OBLIGATION

CONSULTATION QUESTIONS

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

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

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

DESCRIPTION

10.12.1 This scheme shares a lot of common features with Capacity Auctions. The capacity requirement is again determined centrally by the TSO or the regulator based on a recommendation by the TSO. On the other hand, capacity procurement is decentralised as the single buyer in the previous scheme is replaced by market participants having the obligation to present sufficient certificates corresponding to the required capacity. This means that they have some freedom as to how to procure the certificates.

10.12.2 Under a decentralised capacity procurement scheme, such as is being proposed in France, electricity suppliers have to present certificates demonstrating that they have contracted with capacity resources up to a specified level of capacity (typically linked to their contribution for peak demand). In order to improve transparency, liquidity and market power mitigation measures, it may be seen as desirable to enforce that capacity certificates can be obtained through centrally organised auctions with a requirement for gross portfolio bidding (i.e. a vertically integrated company must separately bid in their requirement and their supply). Certificates can also be re-traded.

10.12.3 Again, a penalty is levied if this capacity is not physically delivered to the system at times of system stress (however defined). Penalty payments can be set as high as VoLL.

10.12.4 As with the capacity auction, this option potentially allows for cross border participation in the scheme – however, it requires rules to be clarified about the volume of out of zone capacity that is eligible (normally up to interconnection capacity) and the requirement for delivery by the out of zone capacity.

ASSESSMENT

10.12.5 Unlike Capacity Auctions, Capacity Obligations reduce the level of regulatory intervention as the procurement of certificates is decentralised. This can provide an incentive to suppliers to procure the capability to reduce demand at times of system stress (which would reduce the number of obligations to be bought and revert to innovative providers.

10.12.6 This scheme requires a more proactive approach by suppliers, in contrast to the single buyer variant, with trading (and re-trading) of certificates over a centrally organised platform. New entrant suppliers may need to procure certificates in advance of securing a stable client base leading to potentially onerous credit cover requirements. Therefore, a choice between a Capacity Auction and Capacity Obligation will be influenced by the relative benefits to competition of the two schemes, and the potential need for market power mitigation measures.

10.12.7 Similarly to the capacity auctions, the risk is reliant upon the penalty arrangements in place. On the other hand, investor certainty depends on the hedging appetite of suppliers. The obligation on its own is expected to be for a year ahead with suppliers however being allowed to trade forward to mitigate the risk.

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

10.13 OPTION 5: QUANTITY BASED RELIABILITY OPTION

10.13.1 A Reliability Options scheme is a market-based mechanism relying on financial incentives for delivering sufficient capacity.

10.13.2 A certain capacity requirement is set for a defined period of time, based on an assessment of capacity adequacy performed by the TSO. This capacity requirement is set centrally by either the TSO directly or by the regulator based on a recommendation by the TSO. Reliability options are then purchased to cover the required capacity – these options could be purchased by a single buyer (central agency) or by suppliers directly.

10.13.3 In exchange for an upfront payment in the form of an option fee, the issuer of the reliability option effectively enters into a one-way CfD against a defined strike

price. This one-way CfD forms a contract where the issuer has to pay back the difference between a reference price (for example the DAM price) and the strike price of the reliability option if the reference price rises above the strike price. In the case where the reference price remains below the strike price then no payment needs to be made. Therefore, capacity that is supported by reliability options is incentivised to be available at times of scarcity when prices are expected to be high.

10.13.4 There are two potential alternative solutions for a CRM based on reliability options. Both of them rely on a centrally set capacity requirement with the differentiating factor being the approach to the procurement of reliability options and the strike price setting principles.

10.13.5 In a Centralised Reliability Options scheme a central agency acts as a single buyer with a single strike price for the reliability options.

10.13.6 In a Decentralised Reliability Options scheme it would be market participants that would be allowed to procure reliability options at different strike prices.

10.14 OPTION 5A: CENTRALISED RELIABILITY OPTIONS

CONSULTATION QUESTIONS

1. Are there any changes you would suggest to make the design of a Centralised Reliability Option CRM effective for the I-SEM (for instance a different choice for one or more of the topic?)

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

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

DESCRIPTION

10.14.1 In the Centralised Reliability Options scheme a central agency buys capacity options from market participants at a single centrally determined strike price. The auction is centrally organised and could take form of a 'descending clock' auction as described in the Capacity Auctions scheme.

10.14.2 All reliability options issuers receive an upfront payment set at the clearing price of the centrally organised auction. They then have a financial incentive to be available over critical periods. The associated penalty is determined by a

reference price and is therefore dependant on system tightness as a higher reference price is expected over periods with a tighter capacity margin.

10.14.3 There is a need for a reference price for financial settlement if a reliability option is called. At the moment, the DAM would seem a natural reference price. However, this does not capture the value of capacity close to real-time. If ID auctions are developed, then these could be used to provide a reference price for settling the reliability option.

10.14.4 The use of the DAM would also allow cross-border participation in the Centralised Reliability Options scheme. There will however be a requirement for capacity in a different bidding zone to hold cross-zonal transmission rights (PTRs or FTRs) to be able to access the reference price in the DAM in the All-Island Market.

ASSESSMENT

10.14.5 A Centralised Reliability Options scheme is a market-based mechanism for delivering sufficient capacity.

10.14.6 The strike price will effectively act as a price cap as there will be limited scope for market participants that are under a one-way CfD contract to trade at prices greater than the strike price given the relevant penalty arrangements.

10.14.7 This means that there is a risk of dampened short term energy price signals where the strike price is set at a low level, which for example is below the SRMC of a peaking plant. If, on the other hand, the strike price is too high this will reduce the upfront payments to capacity and will effectively result in an energy-only market.

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

10.15 OPTION 5B: DECENTRALISED RELIABILITY OPTIONS

CONSULTATION QUESTIONS

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

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

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

DESCRIPTION

10.15.1 In the Decentralised Reliability Options scheme market participants trade capacity options with different strike prices over a centrally organised platform. This allows market participants to decide what type of 'products' they wish to buy or sell and meet their obligations via a combination of different strike price and option fees.

10.15.2 This means that a more representative supply curve when compared to the Centralised Reliability Options model will emerge with different 'steps' representing the different strike price levels appearing in the energy market.

10.15.3 There is a need for a reference price for financial settlement once and if a reliability option is called. As with the centralised scheme, the DAM seems to be the obvious choice for a reference market at present (in the absence of intraday auctions), and would also facilitate cross-border participation (where the out of zone capacity holds cross-zonal transmission rights).

ASSESSMENT

10.15.4 A Decentralised Reliability Options scheme is a market-based mechanism for delivering sufficient capacity. It provides market participants with greater freedom for meeting their obligation unlike the centralised version. Therefore, there is greater reliance on competitive forces.

10.15.5 As market participants can procure reliability options at different strike price levels energy prices will be less affected with more 'steps' expected in the price duration curve. This means that there will be strong short-price signals as well as limited distortion in cross border trade.

10.15.6 As with the centralised version, it might be that such a scheme will be more difficult to be perceived as delivering sufficient capacity as there is no 'hard' capacity target.

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

11 NEXT STEPS

11.1.1 This Consultation document forms part of the process for implementing a new High Level Design (HLD) for the Single Electricity Market (SEM) in Ireland and Northern Ireland by the end of 2016. There will be a number of opportunities for additional stakeholder engagement during the consultation period.

11.1.2 The Regulatory Authorities (RAs) will hold at least one open stakeholder forum during the consultation period to discuss the issues raised in this paper. The details of this forum will be published on the All-Island project website (www.allislandproject.org).

11.1.3 The RAs will also hold a series of bilateral meetings with interested parties to discuss the issues raised in this paper. These meetings are currently planned to be held in early/mid-March, and registration details will be published on the All-Island project website.

11.2 CONSULTATION RESPONSES

11.2.1 Responses to this paper are requested by 17.00 4th April 2014. Following a review of the responses to this paper the SEM Committee will publish its draft decision on the proposals set out in this paper in June 2014.

11.2.2 Responses should be sent to Jean-Pierre Miura (JeanPierre.Miura@uregni.gov.uk) and Philip Newsome (pnewsome@cer.ie). Please note that the SEM Committee intends to publish all responses unless marked confidential[45].

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[45] While the SEM Committee does not intend to publish responses marked confidential please note that both Regulatory Authorities are subject to Freedom of Information legislation.

11.3 QUESTIONS

11.3.1 All consultation responses should address the consultation questions in the following order:

PURPOSE OF THIS DOCUMENT (SECTION 1)

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

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

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

TOPICS FOR THE HIGH LEVEL DESIGN OF ENERGY TRADING ARRANGEMENTS (SECTION 4)

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

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

SUMMARY OF THE OPTIONS FOR ENERGY TRADING ARRANGEMENTS (SECTION 5)

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

ADAPTED DECENTRALISED MARKET (SECTION 6)

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

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

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

MANDATORY EX-POST POOL FOR NET VOLUMES (SECTION 7)

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

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

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

MANDATORY CENTRALISED MARKET (SECTION 8)

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

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

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

GROSS POOL – NET SETTLEMENT MARKET (SECTION 9)

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

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

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

CAPACITY REMUNERATION MECHANISMS (CHAPTER 10)

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

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

STRATEGIC RESERVE (CHAPTER 10.7)

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

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

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

LONG-TERM PRICE-BASED CRM (CHAPTER 10.9)

24. Are there any changes you would suggest to make the design of a Long-term price-based CRM effective for the I-SEM (for instance a different choice for one or more of the topic?)

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

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

SHORT-TERM PRICE-BASED CRM (CHAPTER 10.10)

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

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

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

QUANTITY-BASED CAPACITY AUCTION (CHAPTER 10.11)

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

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

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

QUANTITY-BASED CAPACITY OBLIGATION (CHAPTER 10.12)

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

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

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

CENTRALISED RELIABILITY OPTIONS (CHAPTER 10.14)

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

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

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

DECENTRALISED RELIABILITY OPTIONS (CHAPTER 10.15)

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

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

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

12 REFERENCE DOCUMENTS ON THE EU TARGET MODEL

The following documents provide details on the requirements and contents of the EU Target Model.

- Next Steps Decision Paper on 'Implementation of the EU Target Model for the Single Electricity Market' (SEM/13/009)[46];
- Framework Guidelines on Capacity Allocation and Congestion Management for Electricity[47];
- Framework Guidelines on Electricity Balancing[48];
- Network Code on Capacity Allocation and Congestion Management[49];
- Network Code on Forward Capacity Allocation[50];
- Draft Network Code on Electricity Balancing[51];
- Euphemia: Description and Functioning[52];
- Price Coupling of Regions (PCR) initiative and the North West Europe (NEW) project[53];
- Publications by Eirgrid and SONI on the Network Codes[54].

[46] http://www.allislandproject.org/GetAttachment.aspx?id=c23bdd02-bc49-4e21-af67-16bc0b30d994

[47] http://www.acer.europa.eu/Electricity/FG_and_network_codes/Electricity%20FG%20%20network%20codes/FG-2011-E-002.pdf

[48] http://www.acer.europa.eu/Electricity/FG_and_network_codes/Electricity%20FG%20%20network%20codes/FG-2012-E-009.pdf

[49] https://www.entsoe.eu/major-projects/network-code-development/capacity-allocation-and-congestion-management/

[50] https://www.entsoe.eu/major-projects/network-code-development/forward-capacity-allocation/

[51] https://www.entsoe.eu/major-projects/network-code-development/electricity-balancing/

[52] http://www.eirgrid.com/media/PCR_EUPHEMIA_CLARIFICATION.pdf

[53] http://www.eirgrid.com/media/PCR_NWE_MO_TSO_Review.pdf

[54] http://www.eirgrid.com/europeanaffairs/internalenergymarket/

13 GLOSSARY

Balance Responsible Party means a market participant or its chosen representative responsible for its imbalances

Market Participant means market participant within the meaning of the Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale market integrity and transparency.

Unit Commitment means scheduling of generation or load resource for each time interval representing among others: running state of unit; load generation level; and switching states of automatic regulation system. Unit commitment aims at scheduling the most cost-effective combination of dispatchable generation and demand resources to meet forecasted load and reserve requirements, while complying with resources and transmission constraints.

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

Imbalance Settlement means a financial settlement mechanism aiming at charging or paying Balance Responsible Parties for their Imbalances.

Unit-based bid means the bid submitted by a Market Participant that corresponds to potential output from a single generating unit.

Portfolio-based bid means the bid submitted by a Market Participant that could correspond to the combined output from one or more generating units that are part of the Market Participant's portfolio.

Dispatch means the process of determining individual output leading to the physical issuing of instructions to connect, disconnect, increase or decrease output of a generating unit.

Nomination means the market participant's desired position to inform the TSO about the anticipated output.

Scheduling means the process for disseminating the anticipated output of all generating units or portfolios.

Market schedule means the outcome of the scheduling process.

Simple bid means a simple price-quantity bid (i.e. 50MW for the price of 40€/MWh).

Block bid means a bid that refers to more than one hour, potentially with variable output over different periods and has to be accepted as a whole.

Sophisticated bid means a simple sub-order with additional complex conditions (i.e. Minimum income condition, load gradient, scheduled stop).

Regulated bid means a bid that is subject to bidding rules such as price caps and SRMC bidding principles.

Unit-based bidding means the process over which a Market Participant submits bid(s) that correspond to potential output from a single generating unit.

Portfolio-based bidding means the process over which a Market Participant submits bid(s) that correspond to the combined output from one or more generating units and/or the demand side that are part of the Market Participant's portfolio.

Financial Transmission Right means the financial instrument that market participants can use to hedge against price risk arising from congestion in the Day-Ahead Market. For FTR holders it forms an obligation to pay or a right to receive the congestion the Day-Ahead congestion price for the associated energy flow

Physical Transmission Right means the instrument that market participants can use to secure long-term physical access on an interconnector. For PTR holders it forms a right to use the associated interconnector capacity for energy trading

Market maker is a market participant that agrees to provide quotes (buy and sell) on a regular and continuous basis regarding various products in accordance with an agreement between the Member and the Market Operator (Market Maker Agreement).

14 ABBREVIATIONS

AC	Alternate Current
ACER	Agency for the Cooperation of Energy Regulators
BM	Balancing Mechanism
BRP	Balance Responsible Party
CACM	Capacity Allocation & Congestion Management
CCGT	Combined Cycle Gas Turbine
CfD	Contract for Difference
CPM	Capacity Payment Mechanism
CRM	Capacity Remuneration Mechanism
DA	Day-Ahead
DAM	Day-Ahead Market
DC	Direct Current
DCENR	Department of Communication, Energy and Natural Resources
DCs	Directed Contracts
DETI	Department of Enterprise, Trade and Investment
DS3	Delivering a Secure Sustainable System
EC	European Commission
EU	European Union
FTR	Financial Transmission Right
FW	Forward
GC	Gate Closure
HH	Half-Hour
HLD	High Level Design
HLD RG	High Level Design Review Group
IC	Interconnector
ID	Intraday
IDM	Intraday Market
LOLP	Loss of Load Probability
LRMC	Long Run Marginal Cost
M	Month
MCO	Market Coupling Operator
MIC	Minimum Income Condition
MIFID	Markets in Financial Instruments Directive
NC	Network Code
NEMO	Nominated Electricity Market Operator
NWE	North West Europe
PCR	Price Coupling of Regions
PTR	Physical Transmission Right
PX	Power Exchange
RA	Regulatory Authority
REMIT	Regulation on Energy Market Integrity and Transparency
RES	Renewable Energy Sources
SEM	Single Electricity Market

SEMC	Single Electricity Market Committee
SMP	System Marginal Price
SO	System Operator
SoS	Security of Supply
SRMC	Short-Run Marginal Cost
TSO	Transmission System Operator
UIOLI	Use-It-Or-Lose-It
UIOSI	Use-It-Or-Sell-It
UTC	Coordinated Universal Time
VoLL	Value of Lost Load
Y	Year