Market Arrangements for Electricity – Margadh Aibhléise na hÉireann (MAE)

An MAE Consultation by the Commission for Energy Regulation

Under S.I. 304 of 2003

CER/03/230

12 September 2003

1. INTRODUCTION

1.1 S.I. 304 REGULATION 5(1)

S.I. 304 of 2003 was signed by the Minister for Communications, Marine and Natural Resources on the 17th July 2003 and came into force on the 21st July 2003. The S.I. sets out Regulations for the purpose of establishing a new system of trading in electricity. It is reproduced in full in Appendix F.

This document contains a consultation paper by the Commission for Energy Regulation under Regulation 5(1) of S.I. No. 304 of 2003 – Electricity Regulation Act 1999 (Market Arrangements for Electricity) Regulations 2003.

This will result in a decision by the Commission for Energy Regulation under Regulation 5(3) of S.I. No. 304 of 2003 – Electricity Regulation Act 1999 (Market Arrangements for Electricity) Regulations 2003.S. I.

S.I. 304 of 2003 states that the market shall "be a mandatory centralised pool ("the spot market") requiring all electricity exported to or imported from the transmission system or distribution system to be sold to and bought from the SMO."

This paper details the centralised market to be implemented in Ireland under S.I. 304. It sets out how the fundamental design elements of pricing, dispatch and settlement (with respect to both energy and reserves) as set out in the S.I. 304 will operate and will be implemented.

In addition to providing the details of the market design, there are a number of specific issues being consulted upon in this document. These are:

- Consultation 1: Demand Side Participation (Appendix A);
- Consultation 2: Access to Information (Appendix B)
- Consultation 3: Node Design (Appendix C)
- Consultation 4: Pumped Storage (Appendix D)
- Consultation 5: Charging for Reserve Costs (Appendix E)

Responses to the above five issues for consultation and any comments regarding the proposed implementation of S.I. 304 must be submitted to the CER by 5pm on Friday 10th 2003.

1.2 WHOLESALE SPOT MARKET OVERVIEW

MAE is a centralised wholesale electricity market. All electricity generated and consumed is cleared through this spot market.[1] Generators must sell all their electricity to the market and all electricity consumed is purchased by suppliers participating directly from the spot market. Customers who wish to participate directly in the wholesale market require a supply licence.

[1] There may be some exceptions such as small generator units with output less than a defined threshold.

Electricity is bought and sold through the spot market under a market clearing mechanism. The market clearing price is the same for all sellers (generators) at the same location in the transmission system in each trading period. Buyers (suppliers) from the market pay a uniform wholesale spot market price irrespective of their demand location.[2] The SMO settles all trading in the spot market.

The power system is dispatched and controlled by the System Market Operator (SMO) in accordance with the spot market, the grid code and other agreed operational procedures. The SMO is responsible for:

- estimating system requirements (demand, reserves, security constraints, etc);
- issuing dispatch instructions;
- acquiring and using reserves and other ancillary services.

Regulation 3(6) of S.I. 304 of 2003 states that “Generators, with respect to each individual generating unit … shall provide offers to the SMO for each trading period and may change these offers up to gate closure.”

Generators offer their output to the SMO. Generators are responsible for their own generator unit commitment and will develop offering strategies that are aimed at achieving desired levels of operation and profitability. There will be no side payments for unit start-up and shut-down and no separate capacity payments

Regulation 3(7) of S.I. 304 of 2003 states that “A supplier may elect for some or all of its demand to be certified by the SMO as dispatchable. The balance of a supplier’s demand will be treated as non-dispatchable. For its dispatchable demand a supplier will provide offers for each trading period and may change these offers up to gate closure.”

The supply of operating reserves will be co-optimised with the energy market to ensure that energy and reserves are dispatched in unison and to achieve an optimal allocation of both simultaneously (Regulation 3(10) and 3(11) of S.I. 304 of 2003).

Bilateral contracting between electricity generators and suppliers in this market is not directly related to physical power deliveries. Contracts take the form of financial instruments (eg, Contracts for Differences) that allow parties to hedge the financial risk of mandatory spot market participation.[3]

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2 The total delivered electricity cost to final consumers would include a number of cost items in addition to the wholesale electricity spot price. These costs include market costs, transmission charges, distribution charges, PSO levies, contractual obligations, retailer mark-up, etc. There will be some exceptions to this, including the pumping demand of a pumped-storage hydro station.

3 They are not included explicitly in the spot market dispatch or settlement. However, in developing their offering strategy generators will be mindful of their contractual commitments to ensure they fulfil their contracts most profitably. The market provided for Ireland in S.I. 304 of 2003, resembles in principle the wholesale electricity markets in Australia, New Zealand, and Singapore and holds a number of similarities with the PJM and New England markets in the USA.

1.3 WHOLESALE MARKET MEMBERSHIP AND PARTICIPATION

Participation in the market involves both a membership obligation and a technical obligation. There are three major classes of participant:

- Generators
- Suppliers
- Ancillary service providers.

Some entities and some facilities may be registered under several of these classes. Other classifications may be required to deal with specific issues, for example, defining renewable energy generators as a distinct subcategory of generators.

S.I. 304 requires all suppliers and generators to comply with the MAE Rules.

Participants licensed by the CER will be bound by the market rules and technical codes and must meet any additional requirements the CER may impose on them.

- All participants will be required to register their generating unit(s), dispatchable demand and/or ancillary service/reserve providers on an individual basis with the SMO. Registration is mandatory for all participants of the wholesale market. Certain generators may be exempted by the CER under the MAE Rules in accordance with S.I. 304 Regulation 3(3) where it deems appropriate.[4]
- There are also technical obligations on participants as set out in the MAE Rules or the Grid, Distribution, Metering or any other Code as appropriate.

1.4 SYSTEM AND MARKET OPERATION

The System and Market Operator (SMO) will carry out the functions of system and market operation.

A generator is required to operate each of its generating units in accordance with the relevant procedures described in the MAE Rules and the Grid Code. This includes a requirement to operate according to the SMO's dispatch instructions within the dispatch tolerances. This does not preclude the generating unit being offered into the market by an agent. The market participant, however, is accountable for the technical adequacy of the facilities.

The dispatchable demand of suppliers is also required to operate according to the SMO's dispatch instructions where their demand offer is accepted. This issue is considered further in Consultation 1.

An ancillary services participant registers with the SMO specifically with a view to supplying ancillary services. An ancillary services provider has

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[4] These exemptions might include, for example, a generating unit that is too small to be required to participate in dispatch.

additional technical obligations to meet over its energy registration. These include for each facility:

- the class of ancillary services it is capable of providing;
- the facility's technical capabilities of providing that ancillary service.

Ancillary service participants can be generators or suppliers (customers wishing to participate directly require a supply licence).

1.5 DISPATCH AND PRICING

The market is solved simultaneously with dispatch. Dispatch is determined by considering all the system constraints: losses, transmission congestion, system security and reserves. Consequently prices will also take these factors into account. This method prices dispatch according to the technical, physical, and economic structure of the system. This approach helps ensure that market dispatch is physically feasible.[5] Thus, prices can vary by location as a result of losses and congestion in the network. This leads to separate Locational Marginal Prices (LMPs) rather than a single market clearing price.

Prices in the MAE will be based upon the marginal price of supplying additional electricity at each location[6] - although in the case of suppliers, they will not face the pure marginal price directly (see Section 1.5.1 below).

1.5.1 Pricing for Generators and Suppliers

Prices will be determined for each node. There are various ways for these prices to be used. In the MAE market:

- generators will be paid the locational marginal price at their respective injection nodes;
- suppliers (including customers registered as suppliers) will be charged at the uniform wholesale spot market price calculated as the demand-weighted average of the locational marginal prices at the withdrawal nodes in the network.

1.6 OPERATING RESERVES

The supply of operating reserves will be co-optimised with the energy market to ensure that energy and reserves are dispatched in unison and to achieve an optimal allocation of both simultaneously. Chapter 6 discuses how this will operate and how reserves will be paid for.

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5 While the SMO must make every effort to ensure the market solution is technically feasible, on some occasions the SMO may need to use reserves or other ancillary services to ensure system security.

6 This is the cheapest price offered by the next increment of generation - based on the offers received by the SMO - for supplying the increment of demand.

2. *MAE SPOT MARKET*

2.1 SPOT MARKET STRUCTURE

The real-time spot market covers a 30-minute dispatch and trading interval[7]. The length of the interval is a compromise between:

- A short trading interval (eg, 5 minutes), with less potential for changes and disruptions to the *ex ante* dispatch during the trading interval, but greater demands on market clearing and data management systems; and
- A long trading interval (eg, 1 day), with significant potential for changes and disruptions to the *ex ante* dispatch during the trading interval, but lower demands on market clearing and data management systems.

Spot market prices and dispatch instructions are issued at the same time. The spot price and dispatch instructions are set just prior to real time (*ex ante*). Dispatch and pricing are based on offers from generators, SMO estimates of demand and potential demand offers from suppliers.[8]

The SMO will estimate demand for the end of each trading interval for each withdrawal node in the transmission network. The spot market derives a dispatch solution that sets the targets that each generator has to meet at the end of the 30 minutes and the prices that apply to all dispatch during that period.

The market also includes spot markets for several classes of reserves (albeit in a simplified form). All markets are solved simultaneously so that a single optimal dispatch solution is obtained. This solution covers the dispatch of generation and dispatchable demand, and the scheduling of facilities for reserves.

The spot market is cleared (i.e., offers accepted or declined), and the system dispatched, using a computer programme called the dispatch algorithm or Market Clearing Engine (MCE) that optimises the market while ensuring system feasibility.[9]

The spot market is cleared based on estimated demand, with *ex ante* prices applied to the actual (*ex post*) quantities generated in the half-hour as determined by metered data. Settlement for each market participant is their metered generation or demand[10] at the *ex ante* prices.

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[7] The terms “dispatch interval” (the time between formal dispatches) and “trading interval” (the time between successive re-runs of the spot market) are equivalent if formal dispatch corresponds with every time the market is cleared. This is the intention here. Sometimes the market may choose to operate a different trading interval to its dispatch interval

[8] Customers act through their supplier or get a supply licence.

[9] The software typically runs in less than a minute.

[10] Currently ESB PES is deemed to have used all generation that cannot be assigned to suppliers by using meter data, that is, the PES demand is deemed to be the residual. This may continue going forward but is currently being reviewed. While this is important, it does not affect the settlement of the wholesale spot market.

Inevitably, there will be discrepancies between the *ex ante* dispatch targets and actual events. The advantage of the *ex ante* market is that it has firm prices published in advance and is consequently a better informed market for demand side reaction to price. It is based on anticipated conditions so the price is firm irrespective of actual events. The disadvantage is that at times there may be a misalignment between actual events and the *ex ante* dispatch. Reserves and other ancillary services will be used by the SMO to balance the market and handle the discrepancies between actual events and the *ex ante* dispatch during each dispatch interval.

2.2 OFFERS

MAE includes three forms of offers:

- offers by generators to supply energy (electricity) to the market;
- offers by suppliers for dispatchable demand (Consultation 1);
- offers by ancillary service providers to supply reserves (of various categories including demand reduction) to the market.

The option to make half-hourly ancillary service offers will not be invoked immediately in the market, although the facility will be used by the SMO to clear ancillary service contract positions and determine payments under these contracts. The option to move to a full reserves spot market remains.

2.2.1 Structure of Generation Offers

All dispatchable generators are required to make offers for the supply of energy, for all technically available generation units, to the SMO. Simple offers are used that consist of a set of price and quantity pairs (€/MWh; MW).[11] These offers are "energy-only," as there is no separate provision for fixed costs, start-up or shutdown costs or minimum run.

An offer consists of a step-function shaped offer curve - a set of price and quantity pairs where each pair is a tranche (step) of the offer curve.[12] The quantity is the maximum quantity offered at that price. The prices are in increasing order and the quantities are assumed to be cumulative (termed monotonically increasing) with the first tranche commencing at 0 MW capacity and the last tranche accumulating to no more than the maximum capacity of the generating unit.

Portfolio offers are not allowed. Each separately dispatchable generating unit must submit a separate offer curve regardless of ownership, so that each unit's offer curve reflects the unit's characteristics. Generators are expected to develop offering strategies that are aimed at achieving desired generator operation levels and profitability.

[11] It should be noted that the offer price is in terms of energy supply (MWh) whereas the quantity offered is in terms of unit power output (MW).

[12] 10 tranches will give adequate flexibility.

2.2.2 Structure of Supplier Offers

Suppliers are not required to submit demand offers.

However, a supplier may make demand offers if they have a customer with dispatchable demand. That is, a guaranteed quantity of demand which will be reduced if selected and dispatched down by the SMO, and can demonstrate to have done so. All suppliers that have dispatchable demand are required to offer that demand, even if only through standing offers.

Demand offers consist of price and quantity pairs that are monotonically decreasing. They are specified as demand, increasing from zero load and accumulating to no more than the maximum demand certified by the SMO as being dispatchable.[13]

For settlement purposes, this dispatchable demand will be treated as negative generation and charged at its nodal price.

Appendix A addresses the issue of dispatchable demand and demand offers. The Commission welcomes comments and suggestions on this issue.

2.2.3 Generator and Supplier Offer Price Limits

To ensure flexibility in the commercial behaviour of market participants, minimal limitations will be placed on acceptable prices that can be offered into the market. Offers will be accepted for any price between a negative floor price and a positive cap price. The cap and floor price will be determined by the CER. These will be -VoLL and +VoLL respectively.[14] To differentiate between reserve offers that are made at the limit (-VoLL or +VoLL) additional parameters may be required to allow prioritisation.

2.2.4 Generator and Supplier Offer Restrictions

In order to maintain the integrity of the market offers shall be valid estimates of participant's intentions. The SMO will be required to validate the offers. The SMO will have the authority to reject, prior to market clearing, any offers determined to be invalid. Market participants who are found to have submitted an invalid offer will be notified as soon as possible, so that they have an opportunity to re-offer.

The SMO shall determine and publish the criteria it will use to determine how it will interpret the validity of offers. This should take account of:

- the time remaining until the occurrence of the trading interval (the further away the more time other participants have to react to it);

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[13] The assumptions made about the starting point of the demand offers affect the SMO demand estimation. Demand offering can either be starting from zero demand (so the SMO is, by implication, estimating demand WITHOUT any demand being included for dispatchable demand), or offering can be for increments and decrements from estimated demand (so the SMO is estimating demand WITH dispatchable demand included).

[14] VoLL is the "Value of Lost Load" and is an amount determined by CER.

- the impact on the market of any variations to generation or demand offers (a minor change is less important than a major change);
- the nature of the generation unit or facility. For example, a participant operating wind or run-of-river hydro unit may have more latitude than one operating base-load thermal;
- the differing circumstances that may give rise to the need to make a variation.

Consequently, re-offering (refer Section 2.2.6) is required as soon as:

- the existing offer curve is no longer a valid estimate of the offers likely to apply to the real time dispatch, or
- the expected availability of the relevant generating unit or scheduled demand for that trading interval differs from that represented by the existing offer.

The CER, in conjunction with the SMO, may investigate under the aegis of its role in market monitoring and may apply penalties on a participant who fails to present bona fide offers or who fails to take reasonable care to re-offer when previous offers no longer reasonably reflect the expected availability of its facilities. Where offers do not reflect the availability of a facility the SMO may impose additional security constraints if deemed appropriate.

2.2.5 Standing Data

For the smooth operation of the market, all registered participants (dispatchable demand and generation) must provide standing data to the SMO. This standing data, including offers, will apply unless specifically altered by the participant. This standing data reduces the SMO concern that the participants, either accidentally or deliberately, may not provide offer data for a particular trading interval. For participants with static offering strategies, standing data removes much of the administrative burden of operating in the market.

Standing data shall be first submitted when a facility is registered to operate in the market. It shall include information such as unit location; the technical capabilities of the unit; and a default offer curve for generators, or suppliers who are certified as having dispatchable demand.[15]

In addition, the standing data includes "check data" (ie, data against which subsequent data revisions can be validated [14]), to be used by the SMO to assist in determining the validity of any offer.

Standing data may be modified by participants as required at any later date. When modified, new standing data values become the future standing data from the next time standing data is used. Any change in ramp rates and other unit characteristics (either permanent or temporary) must also be notified as soon as possible.

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[15] The default offer curve can be specified by time of day and day of week.

The standing data is used to populate the market input database for any given trading interval. Participants can change the offer, which is derived from their standing data (ie, through a re-offer) for a trading interval. Re-offering the data for a trading interval does not change a participant's standing data, which can be up-dated through a separate process.

2.2.6 Re-Offering

Re-offering is the process of altering offers to construct market offers for each trading interval. Re-offering is not obligatory (except for reasons stated in Section 2.2.4) and without it the standing offers (or subsequently submitted re-offers) become or remain the market offers.

Once participants offers have been received and the corresponding pre-dispatch schedule published, re-offering allows market participants the opportunity to respond to the pre-dispatch information, typically to optimise their financial position or change their physical dispatch.

Re-offers may be made at any time up to gate closure (except in association with re-declaration which will be discussed in Section 2.2.8). The current market offer becomes the data used for all future runs (market projections or real-time dispatch) related to that period until the offer is again re-offer. Re-offers follow the same standard format specified for offer curves and must be valid (i.e., do not violate the check data).

- To ensure the re-offers are accurately received they are formally acknowledged by the SMO and the participant must inform the SMO where no acknowledgement is received. The SMO will also advise the participant when the offer is rejected because it is not a valid offer.

2.2.7 Gate Closure

It is intended that eventually gate closure will be **1 hour** before the commencement of the trading interval.

In the short term, an interim gate closure time of up to **4 hours** before commencement of the trading interval shall be implemented. This timeframe shall be gradually decreased, subject to the Commission's approval.

No participant may alter its offer at or after gate closure, other than in association with a re-declaration.

2.2.8 Re-declaration

There are some events, in particular emergencies (eg, power unit outages) that occur after gate closure but before real time.

In order to allow participants to respond to such emergencies after re-offering has ceased "re-declaration" of availability and demand must be allowed for bone fide and material reasons, up to real time. Criteria for bona fide and material reasons will be set out in the MAE Rules.

Immediate re-declaration is mandatory in the event of a material change in the participant's position.

Participants must immediately advise the SMO of any significantly probable circumstances that will cause a material change in the state of their facilities at any time.

However, in order to discourage inappropriate use of re-declaration, the participant will be required to substantiate any re-declaration after gate closure. The CER, in conjunction with the SMO, may investigate under the aegis of its role in market monitoring and may apply penalties for wrongful re-declaration where deemed appropriate.

At some point, the SMO will no longer accept re-declarations. This is shortly prior to the running of the market clearing engine for the purposes of determining real-time dispatch and pricing.

2.2.9 Security Constraints

Despite the offers, re-offers and re-declarations of market participants the SMO may believe it is necessary for the secure operation of the power system to impose new constraints or relax existing constraints in the market model. Security constraints may have the effect of over-riding offers by, for example, fixing the assumed output of a unit that is not responding to dispatch signals. However, in order to preserve the integrity of the market systems, the SMO will never modify participant offers.

In imposing or relaxing the security constraints the SMO must take into account:

- The commercial interests of participants
- Market priorities, as reflected by the relevant market prices.

The SMO will publish a description of the circumstances that will cause it to impose or relax security constraints subject to regulatory oversight and the action that it may take under those circumstances. The SMO will notify the market and relevant affected participants of the changes as soon as practicable and will record the event.

2.3 DEMAND FORECASTING

The SMO shall forecast the demand for every withdrawal node in each dispatch interval. This is necessary both in order to get a reliable dispatch schedule and in order to calculate market prices.

In addition, demand forecasts shall take account of dispatchable demand, embedded generation and losses incurred outside the transmission network where appropriate.

In practice, it is likely the SMO will have regional forecasts and use demand participation factors for each node in that region. The methodology used shall be subject to regulatory oversight by the CER.[16]

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[16] In other markets, market operators have developed a set of medium-term and short-term demand forecasting tools and models that are used for this purpose.

Special requirements cover demand forecasting when demand load shedding is occurring. Demand must be estimated for both an unrestrained demand (the normal demand estimate) and a restrained demand (the demand after allowing for demand load shedding). These are discussed in more detail in Section 3.11 on demand load shedding.

2.4 MARKET PRICE LIMITS

A price cap of VoLL will apply for instances of energy shortage (where there is insufficient supply to meet demand) In addition, if the price reaches VoLL a number of times in a given period, to be defined, then a period of administered prices may be invoked by the SMO, subject to approval by the CER.[17]

While it is the intention that the market price be limited to the value of VoLL by limiting the offer prices, in practice the LMP prices at a node may exceed VoLL (for example, as a result of losses). Consequently a price cap of VoLL will be applied for settlement purposes.

The precise details of a mechanism for limiting prices are to be determined during the implementation phase of the market.

2.5 PRICING ERRORS

At times, it may not be possible to determine prices or publish prices within the specified time, or the calculated prices are believed to be in error. In this situation, the SMO will issue a "pricing revision notice" before final settlement.

2.6 MARKET SUSPENSION

The SMO, with the approval of the CER, has authority to suspend the market under extreme situations, such as the failure of the power system, the prolonged failure of the market clearing system or when prices peak at VoLL for extended periods.

During market suspension there will be an administered price regime that will be defined in the market rules. These administered prices will be used for settlement purposes until such time as the suspension is at an end.

During market suspension the SMO will determine a dispatch schedule for all generating units based upon the last MCE dispatch schedule, MCE inputs and SMO best judgement in administering a dispatch schedule.

2.7 MARKET MONITORING

The CER, in conjunction with the SMO, shall have a role in market monitoring.

Market monitoring and sanctions shall be consulted upon at a later date as part of the implementation programme.

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[17] As is the case in the National Electricity Market (NEM) in Australia.

2.8 MARKET INFORMATION

The principle is to create an open and transparent market. Information on pre-dispatch projections and ex ante real-time will be restricted to registered market participants. Ex post information will be available to the public after a time and in a format which are yet to be determined.

The issue of access to market, pre-dispatch and outage information is discussed and consulted on in Appendix B.

3.1 INTRODUCTION

The market uses the market-clearing price approach. The market-clearing price is the intersection of the market supply curve and the market demand curve. In its simplest form this means that, in the absence of losses, congestion and reserves, the spot market will have a single price that is set by the marginal market-clearing offer.[18]

When constraints (eg. transmission congestion) and losses are included the price at each node in the network may vary to reflect the losses and congestion. When reserve is co-optimised with energy dispatch, the energy market price will also reflect the implied marginal price of adjusting generation to meet reserve requirements.[19]

Factors affecting the viability of the dispatch schedule include:

- *Losses:* If one generator is electrically further from the demand, its offer will be discounted by the losses incurred in transmitting its generation to the demand. Therefore, the market supply curve of generator offers to meet the demand at a particular location should be adjusted for losses.
- *Transmission congestion:* In some instances the transmission system will not be able to deliver the dispatch schedule implied by a market supply curve. Thus, dispatch is infeasible and a process of "congestion management" is required to reach a dispatch that is feasible. Congestion management is not optional.
- *Reserves:* All power systems need to schedule demand load following and operating reserves to enable the SMO to cope with variations in demand and supply, ensuring the security of the power system in the event of an emergency. In many instances reserves are offered by and required from generators (although sometimes they can be provided by interruptible demand). Reserves impact on the feasibility of dispatch in two ways:
  - *Supply of reserve*: When a generator is offering both energy and reserve there are limits on the amount of each that can be offered. These products are not independent and mutually constrain each other. A feasible dispatch for energy must account for the level of reserve a generator is being asked to supply.
  - *Demand for reserve*: The size of the contingency being covered by reserves depends on the largest generation level dispatched.
- *System security:* In most power systems the SMO will have additional requirements, usually related to reactive power and voltage control,

18 This is distinct from a market that pays each participant the price bid (ie, pay-as-bid).

19 This is true, whether or not reserve is actually traded via the market.

that impact on the security of the power system. These requirements take the form of further constraints on the dispatch schedule.

The essential point of dispatch based pricing approach being used, is that the physical dispatch and the market prices are optimised simultaneously, and are thus mutually consistent. This approach produces a separate price at each location called a Locational Marginal Price (LMP).

3.2 DISPATCH DETERMINATION

The computer software that solves the market, called the Market-Clearing Engine (MCE), determines the dispatch instructions and produces market-clearing prices. The dispatch instructions are consistent with the offers presented by market participants and accepted by the SMO. To achieve this, the MCE must model all of the system transmission and security conditions.

3.3 MARKET NETWORK MODEL

Since the transmission system must be taken into account when determining the market solution it is necessary to define a market network model of the transmission network. It may not be identical to the models used by power system analysts because it has additional functions to perform in modelling the market.

To distinguish the market network from the representation of the strict physical network it is referred to as the “market network model”. It is a representation that enables the solution of the transmission system in a way that also contains the data necessary for solving the market.

The market network model must represent the transmission network under the control of the SMO in a manner that facilitates consistent and reliable operations of the power system and identifies aspects of the trading function of the market that are not present in the physical system. It may contain simplifications, approximations and adaptations that facilitate dispatch, pricing and settlement.

It is the responsibility of the SMO to ensure that the market network model facilitates consistent and reliable operation of the power system. In particular, the SMO will ensure that the model:

- Consistently replicates the transmission network; and
- Contains the simplifications, approximations, or adaptations required to facilitate the dispatch, pricing, or settlement processes.

The market network model is not static. It is dynamic in three ways:

- It may vary between trading intervals with temporary changes in the transmission network,
- It may require permanent adaptation based on the experience of the SMO in using it to settle the market and dispatch the power system; and
- It may require permanent adaptation as a result of permanent changes in the physical transmission system.

The SMO shall adapt or adjust the representation of the market network model as required to accurately operate the market.

3.3.1 Node Design

This section describes the node design intended for MAE. There are two types of nodes required:

- system, or electrical, nodes which represent connections between items of electrical plant (lines, generation units, etc). These are the most basic form of nodes in the representation of MAE; and
- uniform wholesale spot market price node. This node is an amalgamation of system nodes.

The issue of node design is discussed and consulted upon in Appendix C.

3.4 MARKET CLEARING ENGINE

The market is solved by a computer programme that finds the minimum cost set of offers that will supply demand at each of the nodes and will meet all the other relevant system constraints. This is known as the Market Clearing Engine (MCE).

To meet the requirements of this market design the market-clearing engine must be a dispatch optimisation model that simultaneously determines dispatch targets for the end of a trading interval, reserve allocations for the trading interval, associated energy prices at all nodes in the power system and reserve prices.

The MCE is a linear programming model with special attention given to the non-linearity of losses, the impact of negative LMPs and, possibly an interface to an AC load flow model to develop system security constraints. The MCE is defined by an "objective" (which is a mathematical function that represents the measure of effectiveness criterion of the decision) and a set of "constraints" (which are mathematical functions that represent the limitations, requirements and conditions that must be satisfied by every acceptable or "feasible" solution). The MCE finds the feasible solution that provides the best answer to the objective.

3.4.1 MCE Formulation

The objective of the MCE is to maximise the value of dispatched demand load based on dispatch demand offers, minus:

- The cost of dispatched generation based on dispatch offers;
- The cost of dispatched reserves based on reserve offers;
- The cost of constraint violation based on the constraint violation coefficients.[20]

[20] This can equivalently be thought of as minimising the cost of dispatch. The definition is complicated conceptually by demand offers that must be maximised along with minimising the cost of dispatch.

The set of constraints are:

- Constraints representing limits on generation offer, demand offer, and reserve offer quantities;
- Constraints representing the technical characteristics of reserve categories including reserve effectiveness factors;[21]
- Energy balance equations for each node in the market network model;[22]
- Constraints representing limitations on the ramp rate from the unit status at the commencement of the trading interval;
- Constraints defining power system reserve requirements;
- Network constraints, as derived the market network model;
- Loss and impedance characteristics of market network lines;
- Constraints representing the limitations of the operation of interconnectors with other power systems;
- Power flow equations, as defined by a DC approximation to an AC power flow within AC sub-systems; and
- Any additional constraints due to ancillary services or system security requirements or otherwise imposed on the recommendation of the SMO.

3.4.2 MCE Outputs

In solving the market clearing engine the outputs from the models are to be:

- An optimal dispatch that specifies the dispatch targets for each dispatchable generating unit, dispatchable demand, and reserve;
- A schedule of flows on each transmission line corresponding to the optimal dispatch;
- Energy prices for each market network node, and reserve prices defined such that the dispatch targets for each individual participant are optimal for that participant at those prices for their offers; and
- The congestion rental of each link in the market network model.

3.4.3 Constraint Violation Coefficients

At times the solution to the model may not be able to satisfy all the constraints. If such a solution is legitimate – ie not the result of erroneous data - it will most usually occur because of insufficient capacity to meet demand or reserve requirements.

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[21] These are described in Section 6.2.

[22] These also ensure that the net load forecast for the end of the trading interval at each market trading node is met

In the case of insufficient energy capacity this is a demand load shedding event. It is essential that the MCE flags such events accurately, prioritises the violation of the constraints and produces the correct market prices consistent with the event. To accomplish this the model has to include “violation variables” in all of the constraints and corresponding violation coefficients (or violation penalties) in the objective.

Accordingly, violation coefficients:

- Shall be appropriate for, and commensurate with, the particular constraint to which they are to be applied;
- Shall increase, if appropriate, with an increasing violation;[23]
- Shall ensure conflicting constraints are prioritised so that the lowest reduction in the capability of the network, demand or generating units will occur first;
- Shall be set so as to ensure that the prices produced by the market clearing engine will be appropriate in all of the circumstances.

The constraint violation coefficient for each nodal energy balance equation may be set at VoLL. It may differ from node to node and/or be set so as to reflect demand load shedding priorities and it must be no less than any market price cap for energy.

There is an important inter-relationship between the value of the constraint violation penalty, the offer price cap and any market price limits. These must be determined in harmony with each other in order to give effect to the desired price limit policy.

3.4.4 Modelling Approximations

The optimisation model may allow some functional approximations, especially for non-linear functions in order to have the model in a tractable form. There are several ways the approximations can be accomplished but ways should be chosen so that they preserve, under all operating conditions, an acceptable level of accuracy. These approximations:

- May involve producing a piece-wise linear approximation to a non-linear function;
- May involve producing a convex approximation to a non-convex function;
- May include iterative procedures that allow the market clearing engine to interact with other models to produce additional system security constraints or network constraints, and

[23] For example, the price of violating a transmission line rating might increase with the degree of violation to reflect the fact that a small violation might incur very little cost in damage to the conductor whereas a larger violation would incur more significant degradation of the conductor and, in the limit, would induce sufficient sag of the conductor as to drop below the safe clearance to ground.

- May include automated procedures to deal with situations in which a choice must be made to impose or relax overriding constraints.

3.4.5 Model Maintenance, Audit and Publication

It is the responsibility of the SMO to develop and maintain the formulation of the market clearing model, including standards for reliability and processing time. In order to give the market participants confidence in the algorithm:

- the SMO should publish the formulation of the market clearing engine and the performance standards; and
- the formulation of the market clearing engine, the resulting computer software, and the performance standards should be audited and certified by an independent reviewer to comply with the Market Rules and represent a readily achievable standard.

From time to time, the SMO should investigate the scope for further development of the market clearing engine to improve its representation of the power system and its performance.

The market shall be subject to audits. The scope of these audits shall include an analysis that:

- the market systems conform with the MAE Rules;
- that input values are as expected; and
- that output values are as expected.

The CER shall determine the frequency and scope of market audits.

3.5 PRICE DETERMINATION

LMP energy prices and reserve prices are produced by the linear programming optimisation software (the MCE).

- LMP prices will be produced for energy at each node based on the node balance equations; and
- The price of each co-optimised ancillary service will be based on the reserve requirements constraint for that ancillary service.

This may result in prices that vary on a nodal basis in each dispatch period. These LMP prices include the marginal price of energy, transmission losses, transmission constraints and the marginal price of providing reserve, at each node.

3.6 MARKET CLEARING ENGINE DATA

MCE data has two forms, as indicated with the offer data:

- Standing data that is the default data for all runs of the MCE. This data may be changed as required. Any changes replace the standing data permanently until a further change is made to the standing data. (An example of a change in standing data is a permanent upgrade of a transmission line.) These data form the standing database.

- Temporary data that over-rides the standing data for a particular trading interval. (An example of a temporary change in data is the effect on transmission capacity resulting from taking down a line for maintenance.). These data form the data in the market database. This also applies to energy and reserve offers.

At the first (week ahead) pre-dispatch run of any trading interval the market database data will be taken from the data in the standing database.

There are a number of sources of data and conditions on their supply.

3.6.1 Transmission Data

The SMO will hold standing data for all relevant elements of the network.

At any time that there is a material change in the data, either temporary or permanent, the SMO must immediately revise the data in the standing database or the market database, as appropriate.

The SMO will inform market participants of any event that will materially alter the transmission network.

3.6.2 Market Participant Data

Section 2.2 discusses the nature of the standing data and market data that participants provide to demonstrate:

- the physical capability of their facilities, and
- their offers.

3.6.3 SMO Data

The SMO is responsible for the production and update of the various data as soon as possible before the next dispatch or pre-dispatch run. The SMO is required to provide and promptly update data on:

- the current (or where required the projected) status of the power system;
- demand forecasts;
- reserve requirements; and
- any system security constraints.

Any revision to the system representation, constraints and data must take effect, where possible, from the next run of the MCE.

3.7 OBLIGATIONS OF THE SMO IN THE REAL TIME MARKET

The SMO has a number of obligations at various stages of running the real time market and power system. At all times in fulfilling its duties, the SMO shall take full account of its obligations to market participants with respect to maintaining the integrity of the market.

Before the trading interval commences the SMO is obliged to:

- determine the most appropriate configuration and state of the network to be assumed for the trading interval;
- prepare a demand forecast for each node for the end of the trading interval;
- ensure all data has been properly entered into the market databases;
- use the market clearing engine to determine the target loading level for each dispatchable generating unit or dispatchable demand, and reserve facility, for the end of that trading interval (using the latest available data), and
- communicate the target loading levels to participants prior to the commencement of the trading interval.

During each trading interval, the SMO should endeavour, as far as possible, to:

- implement the dispatch targets determined by the Market Clearing Engine;
- maintain system security consistent with the requirements of the Grid Code;
- intervene, if and where necessary using ancillary services; and
- implement demand load shedding consistent with the requirements of the Grid and Distribution Codes.

After each trading interval the SMO should determine and register a series of events for possible scrutiny. There will be a timetable for when these must be preformed. They include:

- any situations where dispatch instructions had to deviate from the dispatch targets determined prior to the trading interval;
- any demand load shedding or other directions issued by the SMO during the trading interval;
- any significant incidents in which contingency reserve was called upon during the trading interval;
- any network constraints and binding security constraints which affected dispatch during the trading interval,
- any additional reports or information as deemed necessary and approved by the CER; and
- any operational irregularities arising during the trading interval, including evidence of participants failing to follow dispatch instructions.

3.8 OBLIGATIONS OF DISPATCHED PARTICIPANTS IN REAL TIME

In dispatching their unit, participants will endeavour to use a linear ramp rate over the trading interval in order to reach the target loading level set for the end of the trading interval. These can vary within the specified dispatch tolerances. This requirement does not need to be met if the unit is responding to specific directions given by the SMO to provide reserve, ancillary services or meet other SMO requirements in the event of an emergency.

3.8.1 Sanctions on Participants

To ensure that market participants are discouraged from acting in contravention of the SMO's instructions, any participant who consistently fails to act in accordance with dispatch instructions issued by the SMO will be liable to a sanction.

The MAE Rules shall detail the grounds on which sanctions will be imposed and the level of penalty. It is expected that penalties will be classified into several categories of severity and subsequent penalty. Market monitoring and sanctions shall be consulted upon at a later date as part of the implementation programme.

3.9 TREATMENT OF INTERCONNECTION

The MAE must have the ability to interface with the existing interconnector to Northern Ireland and with any new interconnectors (eg, an East-West interconnector to Wales) system effectively and efficiently. The existing protocols for the interconnector to Northern Ireland may need to be modified. The treatment of interconnection in the new market will be consulted upon separately in the near future.

3.10 TREATMENT OF PUMPED STORAGE

Appendix D proposes how the market shall treat pumped storage units.

3.11 TREATMENT OF DEMAND LOAD SHEDDING

The SMO under the Grid Code has the responsibility to direct participants and the DSO to conduct demand load shedding.

The need for demand load shedding events will normally be demonstrated in day ahead projections before they are initiated in real time dispatch. If a day ahead projection or real time dispatch indicates that nodal energy prices are expected to be equal to, or exceed, VoLL at any node, then the SMO shall immediately consider the need to initiate demand load shedding.

Under demand load shedding, the market prices will be determined based on an "unrestrained demand", (i.e., the expected demand without demand load shedding).

If demand load shedding is foreseen in the dispatch schedule, the SMO shall endeavour to shed demand load as indicated by the dispatch schedule ensuring continuity between prices and demand load shedding.

If demand load shedding is unforeseen and occurs within the trading period, the SMO will issue a price revision notice and set the prices at the energy price ceiling until such time as the demand load shedding has ceased.

To give the market some degree of certainty the SMO needs to develop and publish the procedures for the management of all aspects of dispatch and pricing in the event of demand load shedding.

4. PRE-DISPATCH MARKET PROJECTIONS

Pre-dispatch estimates of market prices and dispatch quantities will be developed by running the MCE for periods prior to real time, using as inputs the current data in the market database (including current participant offers and SMO demand forecast scenarios etc). The pre-dispatch estimates reflect the latest offer information, demand forecasts, and expected status of the physical system (eg, known line or generator outages). Two pre-dispatch projections are to be developed:

- A week-ahead indicative market projection with six days (excluding the day ahead) of prices and dispatch targets generated for each trading interval for the period beginning on midnight on the day that the projection is prepared. A new set of week-ahead estimated prices will be calculated daily (or more often, in special circumstances) to reflect latest offer information and expected status of the physical system; and
- A day-ahead dispatch projection for between 24 and 72 half-hourly periods generated for the trading intervals prior to each actual dispatch period. The day-ahead price and dispatch estimates will be modified every time the pre-dispatch projections are rerun.

In both instances several scenarios (e.g. for high, medium and low demand forecasts) will be produced at each run of the pre-dispatch.

4.1 WEEKLY PRE-DISPATCH PROJECTIONS

Weekly projections provide an indicative pre-dispatch as an aid to system planning and information to participants of significant forthcoming events, for example, outage schedules and demand variations (such as public holidays etc). The market will be more efficient if such eventualities are known in advance. Stations that are self-committing and have a daily energy limit (e.g. stored hydro) have a particular need to understand the upcoming week.

The projections aid participant discovery of system conditions and the corresponding dispatch and prices. Market participants may choose to update their indicative offers, as they consider appropriate to reflect changes.

In order to give participants more complete information, the SMO shall provide several demand scenarios. In addition, to standard scenarios (eg. high, medium and low demand) the SMO shall produce scenarios for contingencies considered sufficiently probable (but not certain) and material, such as a transmission line outage.

Procedures for week-ahead projections are:

- each day at a specified time the SMO will run projections for each trading interval for the 6 days ahead starting at midnight of the following day.
- each run will use

- the current participant offers;
- the latest system information and requirements available to the SMO on the expected state of the transmission system;
- several demand forecast scenarios or other scenarios considered important by the SMO.

- These projections will be published by a specified time.

4.2 DAY AHEAD PRE-DISPATCH PROJECTIONS

In addition to the week ahead projections the SMO will produce day-ahead projections.

This has two important functions:

- It provides the market with "price discovery" to assist participants in modifying their offers;

- It assists unit commitment. It is particularly important in a self commitment market where generators make offers in order to run their unit as they require. Sensitivity projections, using several scenarios around the demand forecasts, are beneficial to enable participants to accurately assess their strategies.

Procedures for the day-ahead pre-dispatch projections are:

- The first day ahead pre-dispatch will be run at midday (12.00 noon) for each trading interval from midday on that day until the end of the following day (midnight);

- The next and subsequent pre-dispatch runs will be made periodically (probably every 1 to 2 hours) and will always end at midnight. Therefore, there is a horizon from 12 to 36 hours in advance, with 24 hours being added to the horizon at midday when the horizon has shortened to 12 hours.

Each run will use:

- The current participant offers;

- The latest system information and requirements available to the SMO on the expected state of the transmission system;

- Several demand forecast scenarios produced by the SMO and such other scenarios, as the SMO shall decide, similar to the requirements for the week-ahead projections but with finer granularity.

The day ahead pre-dispatch projections are re-run periodically (every hour or more if the software will permit such frequency).

The results will be published immediately they are produced.

In addition to standard projections the SMO should run and publish additional updated versions of market projections in the event of changes that in the opinion of the SMO are material, hourly.

4.3 SOLVING THE MARKET PROJECTIONS

Pre-dispatch projections must be prepared using the Market Clearing Engine for all trading intervals within the relevant time horizon of the projection. As far as possible market projections should emulate the trading interval, as it would be solved in real-time. The MCE should be configured in the same way for pre-dispatch runs as it is for real-time runs.

4.4 PUBLISHED INFORMATION

The published information from the pre-dispatch projection shall contain the information for each trading interval in the period covered by the pre-dispatch projection. There is a policy balance between full disclosure of information and restricted disclosure.

The issue of access to market, pre-dispatch and outage information is discussed and consulted on in Appendix B.

5. OUTAGE PLANNING AND SCHEDULING

5.1 INTRODUCTION

The present outage planning and scheduling regime is described in Chapter OC2 Operational Planning of the Grid Code, version 1.1, dated November 2002.

The format of the new market means that generation and transmission outage information is potentially of great relevance to generators formulating offers and suppliers with dispatchable demand.

The Commission is of the opinion that transparency and access to information where possible are fundamental to the operation of the market. Consequently the Commission is in favour of all possible outage information being in the public domain.

The issue of access to market, pre-dispatch and outage information is discussed and consulted on in Appendix B.

6.1 OVERVIEW

Ancillary services cover the provision of reserves, reactive support and black start. The current arrangements for the provision of the latter two services shall continue under the centralised market design.

There shall be a spot market in primary, secondary and tertiary operating reserves from the commencement of the MAE market. However, at MAE commencement participants shall not be able to make reserve offers. Reserves shall be procured by the SMO. The SMO shall offer these contracted reserves into the reserve spot market at appropriate prices.[24]

The timeframe for allowing participants to make reserve offers directly to the reserve spot market shall be determined by the CER, in conjunction with the SMO and participants.

The supply of operating reserves will be co-optimised with the energy market to ensure that energy and reserves are dispatched in unison and to achieve an optimal allocation of both simultaneously (Regulation 3(10) and 3(11) of S.I. 304 of 2003). This will minimise reserve requirements and the cost of providing them in conjunction with energy offers.

6.2 ROLE OF THE SMO

The SMO is responsible for maintaining the security of the system during the dispatch interval. In order to accomplish this, the SMO will define, procure and use ancillary services including reserves.

The SMO will define the types, amounts and requirements for ancillary services needed to operate the system as per the Grid Code and MAE Rules. Some of these requirements may be set dynamically by the MCE based on a formula related to the state of the power system. Typically these will include defining:

- The requirements for frequency response or demand following service;
- The classes and requirements for operating reserve or contingency reserve classes; and
- Other ancillary services.

The SMO will certify each facility offered for the provision of reserves. As part of the certification the SMO shall determine the reserve capability of the

[24] Experience in other similar electricity markets has been that where an open spot market for reserves has been introduced at the start of the market, the price of reserves has fallen to levels lower than those that had existed at or before the start of the market, for example, New Zealand and Singapore. Those markets that initially obtained reserves under a contractual arrangement found that the agreed contractual price was higher than the prices obtained when they later moved to an open spot market for reserves, for example, NEMMCO in Australia.

facility. If appropriate, the SMO shall determine the reserve effectiveness of different facilities and use this to prioritise the choice of reserve providers in each dispatch interval (this can be achieved within the MCE).

The SMO will receive offers for the provision of reserves, along with the offers for energy, and apply these to the MCE for co-optimisation.

The SMO shall contract for the provision of the other ancillary services on a competitive basis as far as possible. If competition is not present for a particular ancillary service, the SMO shall determine reasonable terms for the contract, subject to regulatory oversight by the CER. In this instance suitable providers shall be obliged under the MAE Rules to supply the ancillary service.

6.3 OTHER ARRANGEMENTS

The SMO will be empowered to enter into contracts with participants which:

- Give it the right to offer their reserve capacity into the market; or
- Require participants to offer their reserve capacity into the market, in an agreed manner; or
- Act as contracts for differences with respect to the reserve spot price, for an agreed reserve quantity.

Such contracts can be employed to provide the system operator with any assurance that may be required with respect to the availability of sufficient reserve to meet operational and/or regulatory requirements.[25]

6.3.1 Structure of Reserve Offers

All ancillary service providers registered to provide operating reserves and demand load following reserves are required to submit reserve offers. In the first instance, the SMO will make offers on behalf of participants based upon reserve contracts. Offers are required for each class of reserve for which the participant is registered. They may apply to generation units or interruptible demand load. Reserve offers are cleared simultaneously with energy offers.

Reserve offers are more complex than energy offers.

- Offers consist of monotonically increasing price and quantity pairs (€/MW; MW) of reserve availability. The price corresponds to the minimum amount the participant would require for each MW of capacity made available for reserve.[26] The cumulative quantity must be no less than zero and must not exceed the maximum reserve quantity that can be supplied.

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[25] In the New Zealand market, for example, extensive use was made of such contracting arrangements in the initial months of the market. But the need for them soon diminished as new reserve sources, such as interruptible load, entered a market that is now, if anything, over-supplied with reserve.

[26] If actually called to provide energy under this arrangement the participant would be paid for the energy at the energy market clearing price at their node in addition to the reserve price paid for being available.

- The offer must include the minimum energy dispatch level at which the reserve response is available and a maximum and minimum operating range.
- The offer must also include the rate at which the facility can respond to reserve provision. This is normally specified as a ratio of reserve provision to energy scheduled, although there may be others.

The offer must be consistent with the capabilities of the facility. Dispatchable demand, where appropriately configured, can be used to provide reserves.

In relatively small electricity systems, such as Ireland, operating reserves are required primarily for frequency management (stability) purposes, as well as for electricity replacement purposes.

Reserves required for frequency management must be fully activated within seconds of the loss of injection, to be determined by the SMO. Offers into the reserve market for frequency management must specify:

- response time;
- capacity;
- price; and
- any other information specified by the SMO.

6.4 OPTIMISING RESERVES AND ENERGY

MAE has a number of features to support energy and reserve co-optimisation.

- Offers for reserve classes will be allowed. These represent the premium a participant requires for having their unit accepted for reserve rather than energy (in the case of a generator) or the price a participant is willing to accept for having their demand interrupted (in the case of interruptible demand). This premium reflects the cost of having a unit(s) available for reserve duty and not being dispatched for energy (for that quantity).
- Reserve requirements are included in the formulation of the MCE. To achieve this the formulation of the market will:
  - Have the cost of providing reserve as part of the cost of solving the market; and
  - Have the provision of reserves as part of the mathematical specification of the requirements to be satisfied by a feasible solution to the market and power system.
- Reserve spot market prices are calculated by the MCE in a manner similar to the determination of the energy spot market price.
- Reserve requirements, provision and prices will be published by the SMO as part of the information from each dispatch and pre-dispatch run.

6.5 OPERATION OF THE RESERVE MARKET

The integrated market for operating reserves will adhere to the following:

1. The SMO will determine an appropriate reserve requirement and inform the market, providing justifications for that requirement.

2. Participants will offer operating reserves, together with their energy offers to supply and/or demand offers, either in the form of spinning or non-spinning reserve from generators, or interruptible demand from suppliers.

3. The SMO will clear all energy and reserve offers in a simultaneous optimisation. A clearing price for electricity and for each class of reserve is calculated, together with the appropriate dispatch schedule. The dispatch schedule will minimise the combined cost (based on offers) of both electricity and reserve to meet the demand and reserve requirement. This may involve having some generation being backed off to provide reserve, and may also involve placing some interruptible demand load on standby and/or reducing the maximum injection into the system to reduce the reserve requirement[27].

4. Where there is a relative shortage of reserve at the initial scheduling stage, the shortage will be notified to the market through the publication of the pre-dispatch projection dispatch schedule and prices. The opportunity shall be given for further offers to be made.

5. Where there is a shortage of reserve during the dispatch interval , there are a number of choices for mitigation:

   - The reserve requirement cannot be met, but the SMO is satisfied that the system security is not at risk, possibly due to the small size and short duration of the reserve shortfall. If this is reflected in a formal relaxation of operating constraints within the MCE, then penalty values should be applied and reserve (and possibly electricity) prices may be very high[28]

   - The reserve requirement cannot be met, and the SMO determines that system security is impaired. The market may be temporarily suspended, and the SMO can exercise discretion to then instruct one or more participants to provide reserve. Under these conditions the market rules will set out the additional compensation that the instructed participants will receive.

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[27] The latter can be optimal, even when there is ample reserve if the largest unit is on, or near, the margin. Compensation may be appropriate, or the reduction may be thought of as providing reserve, to be paid for in the market.

[28] Relaxing constraints without the application of penalty values would create an inappropriate situation in which reserve prices would fall when the supply of reserve proved inadequate to meet normal standards.

6.6 PAYING FOR RESERVES

Each provider will be paid the reserve spot price for each half-hour that its reserve offer is accepted (cleared), and it was placed on reserve duty.

Generation actually called on to generate in response to a contingency, will be paid the LMP at its location for the extra electricity it produces, in addition to its regular reserve payment.

Interruptible demand which is interrupted in response to a contingency, will save the uniform wholesale spot market price for the electricity it would otherwise have consumed, while receiving a reserve payment.

6.7 CHARGING FOR RESERVES

The issue of how reserves should be charged and to whom is addressed and consulted on in Appendix E.

6.8 INTERRUPTIBLE DEMAND AS OPERATING RESERVE

Interruptible demand shall participate in the reserve market where appropriately configured. Interruptible demand shall be offered into the reserve market by the SMO at market commencement.

Interruptible demand which is interrupted in response to a contingency, will save the uniform wholesale spot market price for the electricity it would otherwise have consumed, while receiving a reserve payment.

Interruptible demand that wishes to offer reserve into the reserves spot market must be measurable and verifiable by the SMO.

Demand reduction has the potential to impact prices and provide added security.

- Supplier – Customer Demand Incentives
- Dispatchable Demand (via demand offers)

Supplier – Customer Demand Incentives

MAE encourages suppliers to incentivise their Quarter Hour Metered (QH) customers to reduce demand at peak demand or other high price periods (e.g. scarcity of generation).

A supplier benefits if it reduces demand from its QH customers at high price periods because it does not incur the higher prices for the amount of reduction in demand achieved. In addition, if the supplier has hedge contracts struck at a price lower than the market price it will still receive the revenue (ie, market price minus strike price) from these contracts without actually purchasing some of the high priced electricity. This reduction must be measurable and verifiable by the SMO.

This results in incentives to reduce demand at high price periods but does not directly impact on prices in the spot market. Price is not affected because the reduction in demand takes place after gate closure and therefore does not change the amount of generation scheduled.

Dispatchable Demand

Suppliers are not required to submit demand offers. Suppliers can choose to make demand offers if they have a customer(s) with measurable and verifiably dispatchable demand.

All suppliers that have dispatchable demand are required to offer that demand, even if only through standing offers.

Demand offers consist of price and quantity pairs that are monotonically decreasing. They are specified as demand, increasing from zero load and accumulating to no more than the maximum demand certified by the SMO as being dispatchable.[29]

For settlement purposes, this dispatchable demand will be treated as negative generation and charged at its nodal price.

Demand offers allow suppliers to influence the spot market price prior to real time by reducing demand if price were to rise above the demand offer level. In turn this would change the dispatch, potentially reducing or removing the

[29] The assumptions made about the starting point of the demand offers affect the SMO demand estimation. Demand offering can either be starting from zero demand (so the SMO is, by implication, estimating demand WITHOUT any demand being included for dispatchable demand), or offering can be for increments and decrements from estimated demand (so the SMO is estimating demand WITH dispatchable demand included).

need for the most expensive generation plant. It is possible that relatively small reductions could have relatively large impacts on price in some hours.

Suppliers, in addition to making demand offers on behalf of dispatchable demand, will be required to register the customer, the respective demand characteristics and the component sites with the SMO.

Payment for Dispatchable Demand

Option 1

Dispatchable demand will not be compensated directly by the wholesale spot market for actions resulting from that demand offer.

Benefit will accrue to the customer as a result of:

- a reduction to the spot market price for electricity consumed; and
- incentives provided by suppliers to dispatchable demand to respond to dispatch instructions;

Benefit will accrue to the supplier through a lower uniform wholesale spot market price for all of its remaining demand.

Option 2

Dispatchable demand is paid their demand offer price if dispatched and turned down/off.

Failure to Dispatch

Failure to dispatch demand in accordance with submitted and accepted demand offers made to the SMO is likely to result in additional generation being called upon from the reserve market to provide energy after gate closure. The supplier will pay for any additional reserve requirement.

Example

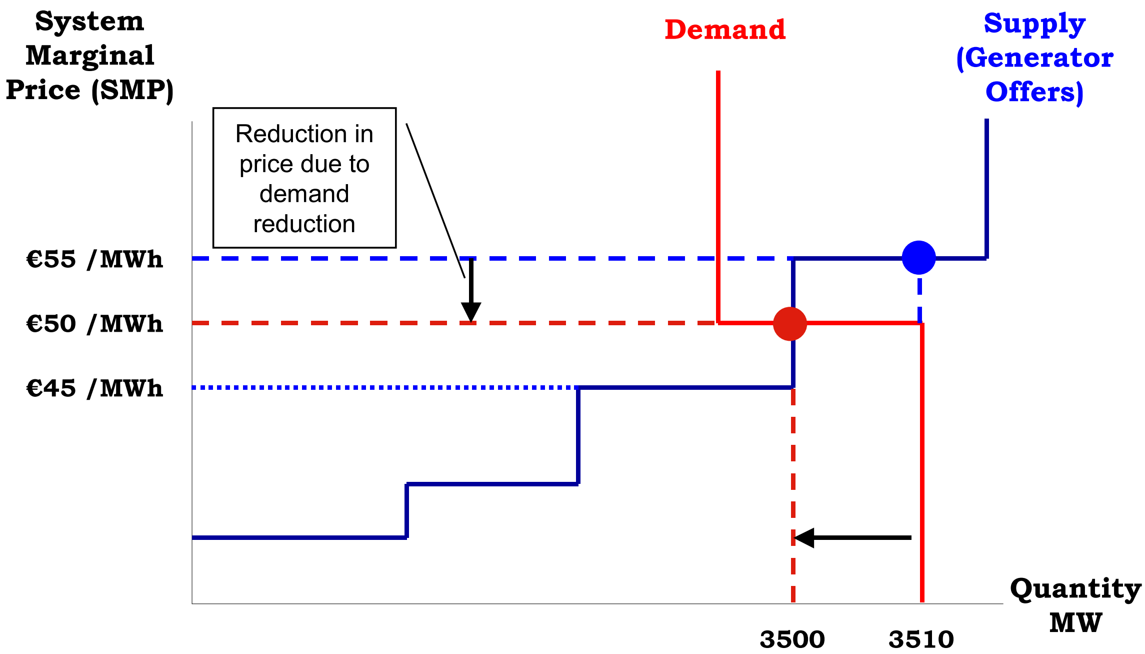
The SMO forecasts that total demand for a trading period to be 3,510 MW (Demand 1). The SMO receives a number of generator offers to meet the total demand on the system.

The spot market price is set, for the demand of 3,510MW, by a generation offer of €55/MWh cleared for 10MW. The next highest generation offer is €45/MWh. This has been cleared in full.

The SMO receives a demand offer for 15 MW from a licensed supplier at a price of €50/MWh. This represents a MWh demand offer on behalf of a customer. 10 MW of this demand offer is accepted instead of the 10 MW of generation at €55/MWh. The remaining 5 MW is not accepted because it is higher than the €45/MWh of the next cheapest generator.

The demand offer is a reduction in demand and is netted off against the 3,510 MW to give a net demand forecast of 3500 MW (Demand 2). The demand offer, at €50/MWh, displaces the last increment (tranche) of offered generation.

As a result, the generation unit that would have been at the margin at a demand level of 3,510MW in the absence of the demand offer, is not dispatched and hence does not set the spot market price. The spot market price is now €50/MWh instead of €55/MWh for all customers and generators. There is no additional compensation to the supplier since, like the marginal generator, the supplier is assumed to be offering at SRMC.



This approach provides a direct link between price and demand, but requires more MAE rules for implementation.

The Commission invites comments and suggestions regarding demand side participation.

The principle is to create an open and transparent market. Information on pre-dispatch projections and ex ante real-time will be restricted to registered market participants. Ex post information will be available to the public after a time and in a format which are yet to be determined.

Market Information

The following table sets out the market information from the spot market to be made available by the SMO.

Time Scale	Information
Each trading interval *ex ante*	• SMO estimates of reserve requirements, demand and system configuration; • The nodal energy prices for each market trading node; • The uniform energy price for suppliers; • The reserve prices for each reserve class; and • Any binding network constraints.
Ex post for each trading day	For each trading interval • The scheduled generation or scheduled demand and scheduled reserves for each generating unit and dispatchable demand.
Ex post, after a suitable time interval	For each trading interval and dispatch offer • Actual availabilities of generating units and dispatchable demand, • Final offers by supplier: • Final offers by unit; • Final reserve offers by unit or supplier; • The time at which any final dispatch offer was made.

The SMO will be required to maintain complete archives of data.[30] [There are cost implications to maintaining a database that is easily accessible to the public. Guidelines on data transfers will be developed, including the payment of costs to those interested in obtaining large quantities of historical data.]

Pre-Dispatch Information

The published information from the pre-dispatch projection shall contain the following information for each trading interval in the period covered by the pre-dispatch projection.

The following table sets out the pre-dispatch information to be made available by the SMO.

Data Type	Data Description
The input data supplied by the SMO	The assumed net demand forecast at each market network node The required level of reserve for each reserve class Any modifications to unit or network availability that the SMO has made for this projection
Dispatch output data from the MCE	The projected aggregate dispatch of scheduled generating units and scheduled dispatchable demand at each market network node The projected aggregate cleared reserve offers for reserve categories
Price output data from the MCE	The projected market price for each market trading node The projected demand-weighted uniform wholesale spot market price Projected reserve prices
System output data from the MCE	Any projected demand load shedding requirement Any projected violations of system security Any projected failure to meet reserve requirements Any trading intervals for which low or inadequate capacity margins are projected to apply Any projected congestion on market network lines.

30 While it is not anticipated that legal disputes between market participants, or between a market participant and the SMO, such disputes have occurred in other markets. In an extreme example of what should not happen, the Californian ISO did not make all data available to the public in real time and apparently did not keep all data that would enable it to run the market for past periods, reducing the tools available to resolve the 2000/2001 California price disputes.

Outage Information

The format of the new market means that generation and transmission outage information is potentially of great relevance to generators formulating offers and suppliers with dispatchable demand.

The Commission is of the opinion that transparency and access to information where possible are fundamental to the operation of the market. Consequently the Commission is in favour of all possible outage information being in the public domain.

The Commission proposes that SMO outage assessments will provide at least the following information to market participants:

- A forecast of demand (SMO estimated and dispatchable);
- A forecast of the available reserve versus the reserve requirements;
- A forecast of excess generation supply (quantities and periods);
- A forecast of unsupplied demand (quantities and periods);
- A forecast of ancillary services adequacy;
- A forecast of congested interfaces, including projected operating limits and flows for internal transmission and interconnections with other jurisdictions, as applicable;
- The most current outage plan of the transmission grid;
- Scheduled generation outage plans – short, medium and long term;
- Total Transmission Capability and Available Transmission Capability on all interconnections to other jurisdictions, as applicable.

The Commission invites comments and suggestions regarding any additional market information which interested parties consider should be available.

This section describes the node design intended for MAE. There are two types of nodes required:

- System, or electrical, nodes which represent connections between items of electrical plant (lines, generation units, etc). These are the most basic form of nodes in the representation of MAE; and
- Uniform wholesale spot market price node. This node is an amalgamation of system nodes.

System Nodes

The system nodes are a one-to-one mapping of the busbars in the physical transmission system, usually as represented in the SMO's Energy Management System (EMS). If there is a node, or busbar, in the EMS, then that node appears as a system node in the market model. Reductions in the modelling of the actual transmission system may lead to operational problems.

An injection node is defined as high voltage side of the generation unit transformer, as is the case in most electricity markets, this makes the pricing node the same for all generation units connected to that busbar. Again, there need be no amalgamation of the generation system nodes into a single market node, because this is done naturally at that high voltage busbar.

Market nodes in MAE, with the exception of the notional single supply node at which the Uniform Wholesale Spot Market price is determined, are identical to the system nodes, which result from a one-to-one mapping of the operational busbars in the Energy Management System.

Notional Single Supply Node – Uniform Wholesale Spot Market Price Node

However, a large number of system nodes may lead to unnecessary detail in the LMPs. The most common area for market nodes might to differ from system nodes is principally at off take points (i.e. demand). It is not uncommon to provide supply from more than one physical busbar at a location. Because each busbar will have its own price, as each is a separate system node, it is not uncommon to amalgamate these system nodes into a single market node at that location where the quantity is the sum of the system node demands and the price is the demand weighted average price of those system nodes.

MAE has a Uniform Wholesale Spot Market Price for suppliers that amalgamates all off take points and there is, therefore, no need to have any local demand market nodes other than this.

The Commission invites comments and suggestions regarding Node design.

The general principle under MAE is that all generation sources will be treated equally unless it is appropriate to provide additional rules.

Pumped storage is a net consumer of electricity. Water is pumped up using electricity to fill an upper reservoir. Water is released through generators to create electricity.

Pumped storage is useful to arbitrage between low and high priced electricity. Water will be pumped up when prices are low and released when prices are high. This is a form of storage, although losses are incurred. The timeframe for this storage is relatively short probably measured in days and so it is relatively short-term price signals that the pumped storage will respond to.

Also, releasing the water from the upper reservoir allows for a very fast response form of generation. Pumped storage can be very effective at providing certain ancillary service and reserves, this is an important function of the units and may be contracted in advance.

In considering the treatment of pumped storage under MAE, it is important to consider the difference between pumped storage as a provider of:

- energy; and
- ancillary services and reserves.

Energy

Pumped storage is both a generator and consumer of electricity at the same node. Any unit can only be a generator or consumer at any point in time.

Pumped storage will be required to maintain both generation offers and demand offers at all times. In the first instance these may be as standing offers. In any half hour the generation and demand offer curves must not cross, the highest demand offer price must not be equal to or higher than the cheapest offer to generate; this will prevent the possibility of the SMO scheduling demand and generation at the same time. Effectively this will provide a break point above which pumped storage is willing to generate and below which it would like to pump up. These offers may change from dispatch period to dispatch period.

When generating, pumped storage will be treated the same as any other generator. When in pumping up mode, the plant will be treated as negative generation and pay the price at the node it is located at for its demand. This amount used by pump storage would not form part of the average customer price calculation.

Ancillary Services and Reserves

Pumped storage can be a very useful provider of ancillary services and reserves. In particular some pumped storage has the ability to change, maybe many times, between pump up and generation modes within a trading period.

The SMO may chose to contract, including long term contracts, with pumped storage to provide ancillary service and reserve contracts. As with any provider of these services pumped storage must demonstrate to the SMO the ability to provide these services. Providing energy must not impact upon the ability and availability of pumped storage to meet its ancillary service contracts. Because the plant may change modes within a trading period it will be important to differentiate between ancillary service and energy provision. Careful definition of energy and reserve offer curves and plant capability will be required to ensure the MCE dispatches the pumped storage in a manner that is physically feasible.

The Commission invites comments and suggestions regarding the treatment of pumped storage.

Charging for reserves shall be on a causer pays basis.

Those who contribute most to the requirement for reserve shall be charged most for its provision.

The contingency for operating reserve is the failure of a generating unit or importing interconnector. The size of the contingency is the highest energy dispatch of any generation unit or importing interconnector in the dispatch interval.[31] The cost of reserves shall be charged in proportion to the requirements for reserves that are deemed to be due to each generating unit.

The contingency for demand following is the variability in both demand and supply (supply being from intermittent and non-dispatchable generators, for example, wind) from estimated values. This requires a formula for charging demand and generators where deemed appropriate, for the cost of demand following in proportion to the variability that they create.

Charging of Participants Exacerbating Contingencies

Situations may arise in which some participants choose to take their unit off-line, or the unit is automatically tripped, when frequency falls during a contingency. This exacerbates the situation increasing the effective size of any contingency, hence increasing reserve requirements and costs. There may be good technical reasons for this and it is not prohibited.

However, the reference point against which such actions should be evaluated, and which is implicit in most reserve market arrangements, is that all participants should be assumed to at least maintain their generation levels during any contingency. Just as those participants that agree to increase output should be rewarded via the reserve market, those participants that decrease output will pay for the costs incurred to deliver alternative provision.

Participants who offer operating reserve quantities which when dispatched do not deliver all or any of the quantity that they committed to shall be deemed to have exacerbated the contingency and shall be treated in the same manner as set out below.

Generators will be treated as increasing the size of any contingency and will pay for reserve.

Participants shall receive the following economic signals to:

- re-engineer a unit to behave in a more stable fashion;
- operate a unit in a more robust fashion;
- make physical arrangements with demand to ensure that their operations have no net adverse effect on system security; or

[31] However, if the larger units were not present, some reserve would still be required to cover breakdown of the smaller units. This argues for cost sharing by all units.

- construct appropriately sized units.

The Commission invites comments and suggestions regarding charging for reserve costs.

Responses to the above five issues for consultation and any comments regarding the proposed implementation of S.I. 304 must be submitted to the CER by 5pm on Friday 10th October 2003.

S.I. No. 304 of 2003

Electricity Regulation Act 1999

(Market Arrangements for Electricity) Regulations 2003

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Electricity Regulation Act 1999 (Market Arrangements for Electricity)

Regulations 2003

ARRANGEMENT OF REGULATIONS

Electricity Regulation Act 1999 (Market Arrangements for Electricity) Regulations 2003

The Commission for Energy Regulation, in exercise of the powers conferred on it under Section 9(1)(d) of the Electricity Regulation Act 1999 (No. 23 of 1999) (hereinafter referred to as "the 1999 Act"), acting in accordance with the policy direction issued to it by the Minister on 26 July 1999 under Section 9(1)(a) of the 1999 Act and having taken into account the matters raised in the public consultation process carried out by the Commission under Section 9(1)(b) of the 1999 Act, hereby makes the following Regulations for the purpose of establishing a new system of trading in electricity.

Citation.

1. These Regulations may be cited as the Electricity Regulation Act 1999 (Market Arrangements for Electricity) Regulations 2003.

Interpretation.

2. (1) A word or expression that is used in these Regulations and is also used in the Act has, unless the contrary intention appears, the same meaning in these Regulations as in the Act.

(2) In these Regulations, except where the context otherwise requires:

"Commission" means the Commission for Energy Regulation established under the Electricity Regulation Act 1999 as amended by the Gas (Interim) (Regulation) Act 2002;

"Counterparties" means suppliers and generators;

"Financial Transmission Right (FTR)" means a financial tradable instrument that allows the holder to hedge the difference between LMPs at different nodes or between LMPs and the uniform wholesale spot market price as set out in Regulation 3(14);

"Gate Closure" means the point in time prior to physical delivery when offers made by a generator with respect to a generating station or individual generating unit or by a supplier become final and changes to offers may no longer be accepted except in exceptional circumstances to be defined by the Commission under the Market Arrangements for Electricity Rules to be developed under Regulation 5;

"Generator" means a holder of a licence to generate electricity granted under Section 14 of the 1999 Act and the Board acting in its capacity as ESB Power Generation;

"Individual Generating Unit" means such a unit of a generating station;

"Locational Marginal Price ('LMP')" means the price per mega-watt hour (MWh) of electricity at a given node;

"Market Operation Date" means the date on which the new system of trading in electricity established by Regulation 3 comes into operation, which date shall be determined by the Commission following public consultation, but shall, in any event, be no later than 19 February 2006. That date shall be published by the Commission by a notice in a daily newspaper published and circulating in the State at least one month beforehand;;

"Minister" means the Minister for Communications, Marine and Natural Resources;

"Node" means a location on the transmission and/or the distribution system where electricity is injected or withdrawn for which an LMP is calculated;

"Offer" means an offer by a generator with respect to a generating station or individual generating unit or by a supplier to the System and Market Operator to sell, to purchase or not to purchase a stated quantity of electricity at a stated price in one or more trading periods under the Market Arrangements for Electricity Rules to be developed under Regulation 5;

"Spot Market" means the mandatory centralised pool market in which the SMO purchases and sells electricity offered by generators and suppliers;

"Supplier" means a holder of a licence to supply electricity granted under Section 14 of the 1999 Act and the Board acting in its capacity as Public Electricity Supplier;

"System and Market Operator ('SMO')" means the National Grid Business Unit of the Board until such date as the Commission determines for the purposes of these Regulations that EirGrid plc is operating as Transmission System Operator and thereafter EirGrid plc;

"Trading and Settlement Code" means the code of that name designated under the Electricity Regulation Act 1999 (Trading Arrangements in Electricity) Regulations 2000 (S.I. No. 49 of 2000);

"Value of Lost Load ('VoLL')" means the price consumers are deemed to be willing to pay to prevent the failure to supply a mega-watt hour (MWh) of electricity as determined from time to time by the Commission using a methodology which shall be made publicly available.

(3) References in these Regulations to an enactment shall include primary and subordinate legislation and in both cases any amendment or re-enactment thereof.

New System of Trading in Electricity

3. (1) The system of trading in electricity and settling electricity imbalances established by the Electricity Regulation Act 1999 (Trading Arrangements in Electricity) Regulations 2000 (S.I. No. 49 of 2000) shall be replaced with effect from the Market Operation Date by the new system of trading in electricity established by this Regulation.

(2) The new system of trading in wholesale electricity will be a mandatory centralised pool ("the spot market") requiring all electricity exported to or imported from the transmission system or distribution system to be sold to and bought from the SMO.

(3) The spot market will apply to all generators and suppliers, except with respect to those classes of generating stations or individual generating units determined by reference to installed capacity or amount of electricity exported or likely to be exported to the transmission system or distribution system, in any calendar year or the primary source of energy used for the production of electricity so exported or any combination of these as determined by the Commission from time to time as exempt in whole or in part from such application and defined under the Market Arrangements for Electricity Rules to be developed under Regulation 5.

(4) The spot market will be an electricity only market and there will be no separate capacity payments.

(5) Generators whose generating stations or individual generating units are not called on to generate because of constraints on the transmission and/or the distribution systems, or because their offered price is too high will not receive any payments from the spot market in accordance with the Market Arrangements for Electricity Rules to be developed under Regulation 5.

(6) Generators, with respect to each individual generating unit, unless exempted under paragraph 3 of this Regulation by the Commission, shall provide offers to the SMO for each trading period and may change these offers up to gate closure.

(7) A supplier may elect for some or all of its demand to be certified by the SMO as dispatchable. The balance of a supplier's demand will be treated as non-dispatchable. For its dispatchable demand a supplier will provide offers for each trading period and may change these offers up to gate closure.

(8) The SMO shall produce and make public week-ahead and day-ahead pre-dispatch runs which will indicate the projected spot market prices and generating station and individual generating unit dispatch schedules prior to actual dispatch.

(9) The spot market shall be cleared and corresponding dispatch schedules determined simultaneously for each trading period, which trading period shall be thirty minutes or such other period of time as determined by the Commission from time to time and detailed in the Market Arrangements for Electricity Rules to be developed under Regulation 5.

(10) The SMO shall simultaneously resolve system feasibility and market dispatch including losses, transmission constraints, reserve requirements and other relevant system security requirements when determining the dispatch schedule and when setting the LMPs in accordance with the Market Arrangements for Electricity Rules to be developed under Regulation 5.

(11) The SMO shall procure and manage ancillary services, including reserves for system support, and shall manage contingencies which may occur during a trading period in co-ordination with the electricity market in accordance with the Market Arrangements for Electricity Rules to be developed under Regulation 5.

(12) Prices offered by generators with respect to generating stations or individual generating units and by suppliers must be no less than the negative Value of Lost Load (VoLL), and no greater than the positive Value of Lost Load (VoLL).

(13) A generator whose offer is accepted by the SMO will be paid the locational marginal price (LMP) pertaining to the node at which it is located for actual volumes traded in the spot market subject to the rules governing same as set out in the Market Arrangements for Electricity Rules to be developed under Regulation 5.

(14) Suppliers trading in the spot market will pay a uniform wholesale spot market price for electricity irrespective of location. Suppliers of dispatchable demand, as certified under Regulation 3(8) will pay the LMP at the node at which they are located.

(15)The method of calculation of the uniform wholesale spot market price and of the LMPs shall be determined by the Commission and set out in the Market Arrangements for Electricity Rules to be developed under Regulation 5.

(16) LMPs will be set by the SMO immediately prior to the beginning of each trading period.

(17) The Commission shall reserve the right to set electricity prices in the spot market and/or to introduce price controls in exceptional circumstances, such circumstances to be defined under the Market Arrangements for Electricity Rules to be developed under Regulation 5.

Financial Instruments.

4. (1) The Commission shall establish a system for the making available by the SMO of FTRs to generators and suppliers, and shall determine the form and content of such FTRs and the procedures for amending such instruments.

(2) The Commission shall impose a suite of financial hedge contracts on or between ESB Power Generation generating stations or individual generating units, the terms and conditions, including price and duration, of such contracts to be determined by the Commission from time to time. The Commission shall determine from time to time the methodology for making these contracts available to Counterparties.

Market Arrangements for Electricity Rules.

5. (1) Detailed rules and procedures necessary to give effect to the new system of trading in electricity established by Regulation 3 shall be developed by the Commission. These detailed rules shall be known as the Market Arrangements for Electricity Rules (“The MAE Rules”) and shall take effect as and from the Market Operation Date.

(2) All generators, subject to Regulation 3(3), and suppliers shall comply with the MAE Rules.

(3) The MAE Rules shall be in such form and contain such detail as the Commission shall decide.

(4) The Commission shall supervise and review the MAE Rules in such manner and at such times as the Commission shall decide.

(5) The Commission may from time to time modify, revise, amend, suspend (in whole or in part), supplement, extend or replace the MAE Rules to such extent and in such manner as the Commission shall decide.

Commission's Directions to the SMO.

6. (1) Subject to the approval of the Commission, the SMO shall develop, operate and maintain the spot market in accordance with the MAE Rules.

(2) The SMO shall comply with any directions given from time to time by the Commission in respect of any performance of its duties, functions and obligations under the MAE Rules.

Commission's Directions to the Board or EirGrid Plc.

7. (1) The Commission may, in advance of the Market Operation Date, issue directions to ESB National Grid Business Unit or, after the date as the Commission determines for the purposes of these Regulations that EirGrid plc is operating as Transmission System Operator, to EirGrid plc in its capacity as prospective SMO with a view to ensuring that the necessary arrangements are put in place to facilitate the taking effect of the new system of trading established under Regulation 3 from the Market Operation Date and ESB National Grid Business Unit or EirGrid plc as the case may be shall comply with such directions.

(2) The Commission, with a view to ensuring that the necessary arrangements are put in place to facilitate the taking effect of the new system of trading established under Regulation 3, may issue directions to the Board or EirGrid plc or both as the case may be, as the Commission deems appropriate and the Board or EirGrid plc or both as the case may be, shall comply with such directions.

(3) Without prejudice to Section 22 of the Interpretation Act 1937 the Board or EirGrid plc or both as the case may be, shall comply with such arrangements and such procedures as the Commission may direct for the settlement of any liabilities accrued before the Market Operation Date and outstanding after that date under the Trading and Settlement Code.

Revocation.

8. The Electricity Regulation Act 1999 (Trading Arrangements in Electricity) Regulations 2000 (S.I. No. 49 of 2000) are revoked with effect from the Market Operation Date.

Commencement.

9. These Regulations shall come into force on 21 July 2003.

Sealed with the common seal of the Commission for Energy Regulation on 16 July 2003.

L.S.

Tom Reeves
Member of Commission

Cathy Mannion
Member of Staff of Commission

The Minister for Communications, Marine and Natural Resources
consents to the making of the foregoing Regulations

Given under the Official Seal
of the Minister for Communications, Marine and Natural Resources
17 July 2003

L.S.

Dermot Ahern
Minister for Communications, Marine and Natural Resources

EXPLANATORY NOTE.

(This note is not part of the Instrument and does not purport to be a legal interpretation.)

These regulations establish a new system of trading in electricity replacing the existing system of trading in electricity. The new system of trading will be a mandatory centralised pool. All generators and suppliers unless exempted will be required to buy and sell electricity through the pool. The regulations make further provision for supplemental rules to be developed by the Commission to give effect to the new system of trading in electricity.