Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

# Commissions Response to Comments Received on the Proposed Decision on the Irish Electricity Trading Arrangements

**July 2003**

**CER 03/179**

## BACKGROUND

This paper is a response to the proposed decision, Margadh Aibhléise na hÉireann – The Irish Electricity Trading Arrangements (CER/03/101) of April 30th, 2003. It addresses the questions and issues raised by respondents following the publication of the above and "Key Design Issues: Generation Adequacy, Dominance and Pricing" (CER/03/097).

Comments received pertained to specific aspects of the proposed market design and whereas these may be reasonable in isolation, it is the Commissions view that the market design must be internally consistent and must be viewed as a package. This document should be read in this context.

Responses to the various issues and questions submitted are as detailed below.

## LOCATIONAL MARGINAL PRICING (LMP)

The Commission notes that a number of industry parties have commented that the proposals for locational pricing are complex.

Operating a physical electricity system is complex, whatever method is chosen to achieve this. The first attempts at electricity markets did not have the software or processes to integrate physical and economic details of the system. Integrating these is now understood and used in several countries, improving efficiency. Although this appears complex it merely combines all the operations that have to take place in one integrated package.

The paper, 'Congestion Management in Non-LMP Markets: Case Studies' published March 31st 2003 commented on experience with non-LMP pricing in a number of markets. This note provided strong evidence of the problems encountered by non-LMP approaches to electricity market pricing and congestion management.

Appendix A contains a comparison of the LMP approach with alternative approaches. Appendix B includes an independent summary of the LMP approach (known as FNP) used in New Zealand.

The Commission considers locational pricing to be a simpler, more transparent and more accurate means of congestion pricing than exists at present.

### FINANCIAL TRANSMISSION RIGHTS (FTRs)

***Are FTRs suitable to mitigate basis risk for wind (variable) generators?***

***Will the CER issue FTRs free to renewables/CHP as a result of the environmental benefits they bring?***

***Will FTRs be changed regularly to reflect changes in the network (generation, demand etc)?***

***Will FTRs be allocated to existing generators?***

***How long will these FTRs be 'grand fathered' for?***

***Will any settlement deficit be recompensed through TUoS charges? How will a node-to-node right work if customers are charged an average price?***

***How will FTRs link with the long-term development and planning of the National Grid?***

The Commission is of the view, based on evidence and experience from other LMP markets, that basis risk between nodes will exist. Because of the difficulty of implementing significant changes after the market goes live and the desire to have a sustainable trading arrangement requiring minimum intervention, FTRs are considered necessary from the outset of the new trading arrangements. The details of the FTR scheme will be addressed during the implementation phase. The Commission notes the questions and concerns of participants and is keen to address them going forward.

## CAPACITY PAYMENT

The Commission notes that a number of respondents throughout the design phase of the trading review have favoured an explicit capacity mechanism.

The paper titled 'Capacity Payment Issues' published 31st March 2003 included a detailed discussion of capacity payments.

It is important to note that the pricing approach decided upon for Ireland includes an implicit capacity payment based upon the economic principle of marginal pricing.

It has been suggested that an explicit capacity payment should be allocated to plant available to generate.

The Commission has seen no evidence in any market where explicit capacity payments have had the effect of encouraging new entry.

As noted in the above-mentioned paper, the Commission believes that an explicit capacity payment would:

- Severely blunt spot market price signals;
- Add to the costs of producing electricity in Ireland;
- Place a considerable technical and administrative burden on CER;
- Raise prices for consumers;
- Reduce incentives to re-furbish or build on existing sites;
- Result in a net transfer of wealth from consumers to generators;
- Do little (if anything) to increase security of supply.

As a result, the Commission believes that a capacity payment would increase overall costs to consumers without resulting in new entry.

## DEMAND SIDE RESPONSE

***How does the market encourage demand side response?***

Suppliers will have hedge contracts with generators based on a contract or strike price. When prices are higher than the contract price generators will pay the difference in the market price and the strike price to the supplier for a fixed volume of capacity. If suppliers reduce the capacity (i.e. if their demand is reduced), they still get paid for the contracted volume. Thus, unlike the current market suppliers will be financially rewarded for getting customers to reduce their demand at times of peak load. They can pay some of the 'profit' back to the customers and so reduce overall customer costs.

In this market customers can also 'bid' directly into the market. This would only apply to very large customers who can control their output reasonably accurately. They can 'bid in' a demand quantity that they will turn off if the price reaches a certain level. The market operator can accept these bids and dispatch the load in the same way as they would a generator.

Customers will also be able to participate in the reserves as at present through interruptible tariffs or 'powersave' programmes. In this way an efficient reserves market can be operated and customers can reduce their costs.

## PRICE SIGNALS & GOVERNMENT INTERVENTION

***Will prices be allowed to fluctuate in the new market? Will end-customers see those fluctuations in real-time?***

Prices will be allowed to fluctuate in the spot market, although they will not be allowed to rise above or fall below the positive or negative calculated Value of Lost Load (VoLL) and if VoLL is achieved repeatedly administered prices may be introduced as in Australia.

Suppliers may choose, indeed it is envisaged that they will choose, to hedge these price fluctuations through bi-lateral CfD contracts. Customers, therefore, will only be exposed to average prices that are also likely to include periods with very low prices.

Some customers, probably larger customers, may wish to curtail their usage switch when wholesale prices reach a certain level. Such customers may turn off their load at peak times or shift load to cheaper periods. As high prices reflect periods of relative shortage this will benefit all customers but also result in lower average prices for those that choose to moderate their behaviour. Customers with interval metering would be well suited to responding in real time either directly to wholesale prices or at the request of their supplier. Suppliers, however, are incentivised to reduce all demand at high price times and can put in place tariffs for customers with non half hour metering to incentives them to reduce also.

## RENEWABLES

***Will renewables get priority dispatch?***

Insofar as the operation of the national electricity system permits, the new market allows renewables priority dispatch.

***Will renewables pay for their contribution to grid reserve requirements?***

One of the Commission's duties is to have regard to promote the use of renewable energy without prejudice to the maintenance and safety of the grid. The provision of reserve by the SMO maintains the safety of grid.

More specifically, the SMO requires reserves to meet obligations imposed by the Grid Code. Costs imposed on the SMO and thus on the market are first of all, operating reserves which are required to cover for the generation units and transmission circuits that are deemed to impose the contingencies, and secondly, the cost of regulating reserves by the SMO.

A "causer-pays" approach to reserves suggests that those who cause the need for reserves (that may not otherwise be present) should pay for those reserves.

The variability in load and supply from intermittent generators adds to the need for reserves. A causer pays approach would allocate operating reserve costs accordingly. Likewise intermittent and non-dispatchable generators would be liable to pay for a proportion of the cost of regulating reserve.

***Is the decision in line with policies put forward by the European Commission (CEC) as set out in its medium term strategy paper concerning electricity?***

Bilateral contracting will be allowed for in the new market via financial hedging contracts such as Contracts for Differences. The CER understands that the CEC's strategy papers are not formal EU policies. Likewise, the strategy paper in question is in draft form, and as such may change.

***How will Renewable Generation be affected by the decision?***

Renewable generators will have a ready market for all of their generation, subject to system security constraints. Capacity payments are implicit within the market clearing price which will apply equally to renewable and non-renewable generators. Renewables will be able to hedge against price volatility in the same way as other generators.

***How will renewable generators with AER contracts be affected?***

The output from these generators will have to be bid into the spot market. This could be done by the generators themselves or by an agent on their behalf. For those with AER contracts, the PES may act as the agent in this regard. The AER contracts will act as a hedge against pool prices. Therefore, AER generators will simply receive the AER contracted price.

***How will renewable generators acting outside the AER scheme be affected?***

Renewable generators acting outside the AER scheme will bid their output into the pool. They will be free to enter into bilateral financial contracts in which case their effective revenue will be based on the contracted strike price. If they have no financial contracts they will receive the pool price for their generated output.

***Will the Central Trader obligation include any obligation to buy off CHP/Renewables?***

The Central Trader concept, that may or may not be implemented, is designed to address the market dominance issue. The functions and obligations of the central trader will be consulted on prior to the introduction of such an entity.

***Is a decision to allow negative pricing contrary to the interests of renewables?***

Negative offers allow plant that require long start up times to signal that the shutting down and start up costs exceed the cost of remaining on load and allow plants to pay to stay on load so that they will be in the position to generate in subsequent periods when prices are positive. It is expected that negative prices will not be a common practice. No decision has been made in relation to whether or not renewable generation will be exposed to negative pricing. This will be consulted on in the implementation phase.

***Are AER contracts affected/breached by negative pricing?***

AER contracts are not affected by negative pricing.

***Will renewable generation be guaranteed dispatch?***

Renewables will receive priority dispatch given system security constraints in line with the Electricity Regulation Act, 1999. The paper on renewables, 'Trading Arrangements & Renewables' published April 30th 2003, raises some of the issues pertinent to priority dispatch that will be addressed during the implementation phase.

***Are renewables guaranteed transmission?***

The market design provides the same level of transmission access to all generators. All generators whose offers are accepted are guaranteed dispatch. To the extent that renewable generators are offered priority dispatch they will be guaranteed transmission.

***Will renewables be financially compensated for transmission and distribution constraints?***

There will be no constraint payments. The cost of constraints will be implicit in the spot price.

***Are grid upgrades necessary to guarantee the transmission of renewable generation?***

The network requirements for transmission of renewable generation is specific to each project.

***Can large-scale renewables follow dispatch instructions? How will this be modelled in the MCE?***

Large-scale renewables may be able to follow dispatch instructions with the right equipment. This can be accommodated in the market clearing engine.

## KYOTO PROTOCOL

***How will the trading arrangements contribute to Kyoto Incentives?***

While the trading arrangements in themselves are not designed to contribute directly to achieving our commitments under the Kyoto protocol, there are inherent features in the market design which can usefully be employed to facilitate initiatives in this regard.

The optimum dispatch, derived from the Market Clearing Engine, means that the most efficient use is being made of our resources and this will contribute to minimising emission levels.

The incentives for demand side measures inherent in the market act to promote energy efficiency and thereby control emission levels. In particular, the reduction of peak load due to demand response should reduce the need for capacity and this will reduce emissions.

If Carbon Taxes are introduced, it is envisaged that generators will add these costs to their offers. This may change the dispatch order as prices will now be inclusive of the additional costs placed on generators relative to their emissions. Renewable generation will benefit from the improvement in the relative costs of generation between them and non-renewable generation.

## PSO

***How does the Commission's decision impact on the PSO Levy?***

The application of the PSO levy is a matter for the Minister. The proposed decision has no impact on the PSO levy.

## CHP & EMBEDDED GENERATION

***How will CHP plant be treated in the market?***

***How will embedded generation be treated? What prices will embedded generators face when exporting and importing?***

***Will CHP be treated on the same basis as renewable generators?***

Details of how CHP and embedded generation will be treated under the new arrangements merits further discussion and will be consulted on during the implementation phase. The Commissions objective is to encourage efficient CHP development in line with government and EU policy.

## GENERATION ADEQUACY

***Will the fast-build option have a dampening effect on price spikes and thus act as a deterrent to new entry?***

The fast build option anticipates that only peaking units will be built. This will only occur if there is a clear need and the market has not responded. The basic concept of the fast build approach is that it enables the Commission to trigger the option only after it is clear that investment will not take place in time and system security conditions are projected to be breached in the absence of intervention.

It is possible that this option would remove some VoLL price spikes from the market (ie, reduce the hours that the market does not clear so that load must be curtailed). However this effect will be minimal as there are unlikely to be many such trading periods in a year where VoLL will be reached and also as the plant will be peaking plant only.

## MARKET DOMINANCE & CENTRAL TRADER

Throughout the review and consultation process market dominance has been highlighted as a key issue in Ireland. This view has been supported by most participants.

In the absence of structural reform used in many other countries, the CER will need to implement measures to control market power, including regulation and Vesting Contracts. These measures may be supplemented by a Central Trader mechanism or a forward contracts market. The Commission are still considering the options available to manage dominance in the market.

## INTERCONNECTION WITH NORTHERN IRELAND

The issue of how an interconnector will work after the new arrangements are put in place will be decided in the implementation phase. It will be necessary to examine how trading will take place across the interconnector if the Irish and Northern Irish market are separated or indeed integrated into an all-island market. It will also be necessary to examine how trading will take place across an east /west interconnector physically connecting the UK and Irish markets. These issues will be consulted on during the implementation phase.

***How will negotiated hedge arrangements and FTRs be applied in respect of cross-border trades?***

This is dependent upon the decision on how trading across the interconnector will occur if the northern and southern markets are not co-incidental. This will form part of the consultation above. This is not an issue in the context of an all-island market.

## OTHER

***How will the Transmission Use of System charges be dealt with in the market?***

This will be the subject of a review of transmission tariffs to be undertaken in 2004.

## Appendix A: Comparison of LMP Approach with Alternatives

The following table compares the Irish LMP approach to two alternatives, namely:

- Optimal dispatch using the LMP market clearing engine but with averaged LMP for both buyers and sellers
- The Uniform Price approach in the old England & Wales market.

These are the most viable alternative models for a centralised market. Comparing the Irish LMP approach to other alternates such as the zonal pricing in California, other different LMP approaches (eg, PJM does not include losses in LMP prices), or the Australian simplified node approach would not help achieve this objective.

Third, we have created two parts in this table, pricing/dispatch and systems/processes. These two things reflect the question asked. Different approaches are possible.

| **Pricing and congestion management approach** | **Irish LMP** | **Uniform Price Optimal Dispatch** | **Former E&W pool** |
|---|---|---|---|
| Brief Description of the approach | Dispatch and market outcomes determined simultaneously; full locational marginal prices, including losses, for generators; load-weighted average of LMP for buyers; congestion managed through security-constrained dispatch and reflected in prices | Dispatch and market outcomes determined simultaneously; weighted average of LMP for generators and buyers; congestion managed through security-constrained dispatch and reflected in prices; socialized congestion cost recovery (ie, uplift charges); losses addressed through locational loss factors | Dispatch influenced by but determined separately from the market; locationally uniform prices for generators and buyers; congestion managed through non-market adjustments to generators with socialized congestion cost recovery (ie, uplift charges); losses addressed through locational loss factors |
| **Pricing/Dispatch** | | | |
| Generators dispatched and paid based on offers | ➨<br>LMP has generators dispatched and paid based on their | ➨<br>Generators dispatched based on their offers; price adjustments | No<br>“Unconstrained” market dispatch different from actual system |

| Pricing and congestion management approach | Irish LMP | Uniform Price Optimal Dispatch | Former E&W pool |
|---|---|---|---|
| | offers | resulting from averaged prices requires side (compensation) payments and, if single uniform price (but not if two separate uniform prices) there is a settlement deficit resulting from uniform price | actual system dispatch, so payment must be adjusted by congestion management and side (compensation) payments and there is a settlement deficit resulting from uniform price |
| Losses reflected in dispatch and prices | ➨ Dispatch includes average losses; LMP reflects marginal losses; difference between average and marginal losses distributed through the settlement surplus. | Partially LMP prices include marginal losses but averaging socialises them; need additional loss calculation based on average loss factors to attribute losses and settlement surplus from marginal losses. | No Dispatch includes average losses; cost of losses not included in market prices but are calculated using long-term loss factors and are recovered indirectly |
| Transparent and predictable prices | ➨ LMP prices are fully transparent; demand levels and generator bids are public and can be reviewed | Partially transparent Uniform prices are transparent, but some of market operation and cost is buried in various out-of-market compensation adjustments and uplift charges | Partially transparent Uniform prices are transparent, but much of market operation and cost is buried in various out-of-market compensation adjustments and uplift charges |
| Uniform locational prices for customers | ➨ Load-weighted LMP prices; some adjustments for distribution of settlement surplus. | ➨ Actual prices are different from unconstrained spot prices, with considerable amounts put into | ➨ Actual prices are different from unconstrained spot prices, with considerable amounts put into |

| **Pricing and congestion management approach** | **Irish LMP** | **Uniform Price Optimal Dispatch** | **Former E&W pool** |
|---|---|---|---|
| | | uplift charges and loss factors; prices are higher than under an LMP regime. | uplift charges and loss factors |
| Dispatch Efficiency | ➨<br>Market is dispatched optimally based on offers and bids as well as all system requirements. | ➨<br>Market is dispatched optimally based on offers and bids as well as all system requirements; out-of-merit dispatch may result in different offering strategy to capture greater compensation payments. | No<br>Sub-optimal dispatch; reconciliation of market schedule and feasible system dispatch results in out-of-merit scheduling of plant |

| **Pricing and congestion management approach** | **Irish LMP** | **Uniform Price Optimal Dispatch** | **Former E&W pool** |
|---|---|---|---|
| **Systems and processes** | | | |
| Single Market-Clearing Engine | ➨<br>LMP & dispatch are outputs | ➨<br>LMP & dispatch are outputs; further calculations required for compensation payments and loss attribution | No<br>Multi-stage process:<br>MCE for unconstrained dispatch, pricing and settlement Dispatch engine informed by MCE outputs<br>Congestion management adjustments,<br>Loss calculations using average loss factors independent of dispatch process |
| Reserve market connected to energy market | ➨<br>Co-optimised energy market and reserve markets; LMP and reserve prices reflect the cost and provision of reserve; reserve provision and requirements determined dynamically; MCE gives optimal and feasible joint dispatch of energy and reserves | ➨<br>Co-optimised energy market and reserve markets; LMP and reserve prices reflect the cost and provision of reserve; reserve provision and requirements determined dynamically; MCE gives optimal and feasible joint dispatch of energy and reserves; any gaming of compensation payments in the energy market will distort the reserves market | No<br>Reserve are separately procured; scheduled and priced; no formal relationship between reserve provision and energy dispatch. |

## Appendix B: NZEM "Five Expected Outcomes" of FNP

### *Introduction*

NZEM has employed a full nodal pricing model since its establishment in October 1996. After five years of operation, the NZEM Rules Committee considered it timely to conduct a review of the outcomes of nodal pricing. The Committee agreed on terms of reference for the review, including that it should:

- Review the outcomes expected when the full nodal pricing model was chosen in 1996;
- Review the actual outcomes produced by the nodal pricing model from October 1996 to the present;
- Contrast expected and actual outcomes, providing an analysis of whether the expected outcomes were achieved and, if not, why not; and
- Recommend how the nodal pricing model could be improved to achieve the expected outcomes.

The Rules Committee engaged the services of Trowbridge Consulting to conduct the review. The Trowbridge report was completed and released in later 2002.

### *Overview of the review findings*

The five expected outcomes, reflecting the basis for choosing an FNP model in 1996 were[1]:

1. Efficient short-run operation
2. Efficient long-run operation
3. Ability to manage risk
4. Effective retail competition
5. Competitive price discovery.

The review findings with respect to each of these five outcome areas are as follows:

*1. Efficient short-run operation*

The review found that full nodal pricing (FNP) has resulted in the efficient short run operation of the market "to the extent that the market prices are determined by the competitive interaction of suppliers and buyers".

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[1] Page iii of the 'Trowbridge report' otherwise known as 'Assessment of Outcomes Achieved by Full Nodal Pricing in the NZEM', NZEM Rules Committee, November 2002. http://www.m-co.co.nz

However, it also made reference to a number of other factors outside of the FNP market design that could and in some cases did affect outcomes. These included; technological and other constraints to effective demand side participation, transmission pricing methodologies and grid operation practices.

2. *Efficient long-run operation*

The review found that FNP did further the efficient long run operation of the market to the extent that it encouraged new generation investment to locate in the high price areas (close to Auckland).

However the evidence with respect to the location of new loads at low price nodes and new investment to relieve transmission constraints was less clear.

The lack of contract market liquidity (primarily due to the vertically integrated nature of the industry) was also identified as an issue with respect to new investment.

3. *Ability to manage risk*

As indicated above, the review found that FNP contributed to a relatively inactive hedge market – although the primary cause can be put down to the vertically integrated nature of the industry, and the resultant natural hedges.

The review noted that, in the absence of FTRs, basis risk was essentially unmanageable. It noted further that the potential effectiveness of FTRs as a risk management instrument was limited to an extent by the inactive hedge market described above.

Finally the significance of basis risk could, at least to an extent, be attributed to a lack of appropriate investment in transmission.

4. *Effective retail competition*

The review found the retail market to be dominated by regionally based vertically integrated utilities. The resultant lack of liquidity in the contracts market and the relative lack of new investment in transmission was found to constrain the ability of FNP to facilitate national retail competition.

5. *Competitive price discovery*

It was found that information on high price outcomes was clearer to market prices under FNP than under alternative pricing regimes.

However, it was also noted that the economic impacts of high nodal prices on users who lack practical means to respond could be severe

### *Overall conclusions*

Overall, the review found that there were significant benefits of FNP including efficient dispatch and efficient price signals. However there were also some associated areas of shortcoming including the regime governing new transmission investment, a lack of liquidity in the contracts market, a lack of means for managing inter-nodal basis risk and the burden associated with extreme price outcomes.

The report concluded, importantly, that "where market outcomes that the FNP model was expected to achieve have not emerged, the causes of failure, in many cases, can be attributed to impediments unrelated to market design".

### *Lessons for the Irish Market*

The selection of the trading arrangements for Ireland has given explicit recognition to the advantages of locational marginal pricing in terms of the efficient short and long run operation of the market.[2]

In addition, the proposals for the Irish market have incorporated some specific refinements that build on the New Zealand experience so as to be able to capture the obvious benefits of locational marginal pricing without necessarily being encumbered by the shortcomings experienced in New Zealand (bearing in mind the conclusion that many of the shortcomings stem from outside the market design). Key refinements are outlined below:

*A.* *Uniform pricing for customers*

Uniform pricing for customers will temper price volatility on the demand side, remove some of the basis risk and assist with the development of a more liquid contracts market. The New Zealand experience (that locational price signals seemed to be less important on the demand side) indicates that the loss of efficiency associated with the muting of demand side price signals is unlikely to be significant.

*B.* *The introduction of Financial Transmission Rights*

The introduction of FTRs will provide a mechanism for managing the basis risk from market start. Note as indicated above, basis risk is already reduced courtesy of the uniform price on the demand side. In addition, Ireland's more favourable regime for new transmission investment will also serve to reduce basis risk vis-à-vis New Zealand.

*C.* *Provision for demand side bidding*

Unlike the New Zealand market, there will be provision in the Irish market for demand side bidding. This will improve demand side participation vis-à-vis the New Zealand variant.

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[2] *Irish Electricity Trading Arrangements Second Options Paper* 24 January 2003

*D.* *Ex-Ante Pricing*

Similarly, the Irish market differs from the New Zealand market in that it will have ex ante pricing, whereas the New Zealand market is an ex post market. Like the provision for demand side bidding, this will improve demand side participation.

*E.* *The proposal for a Central Trader (or similar) mechanism*

Finally, there is a proposal for a Central Trader or similar mechanism for the Irish market thereby breaking the vertically integration that ESB would otherwise have. This can be expected to increase the liquidity of the contracts market.

## Appendix C: Examples of Trading & Interconnection between Various Markets

There are some analogues in other markets that may provide some examples for Ireland:

- DC merchant interconnectors in the Australian market. The DirectLink and MurrayLink projects in Australia are privately owned and operated HVDC transmission lines that function in the Australian market. While there are details beyond the scope of this paper, these projects participate in the market as either a load or as a generator due to the ability to control/dispatch the flow across the lines.
- The France to UK connector. Without providing details of the operation and the auctions, capacity on this interconnector is auctioned to the market periodically. The auction winners then are able to trade in the markets on either end of the line.
- The various interconnection agreements in place in the US between markets and between system operators. These agreements reflect, to a large extent, non-market scheduling arrangements related to largely uncontrollable AC lines.[3] As CER heard in their field trips, it is these per-market arrangements that give rise to "seams" issues in the US. One of the goals of FERC was to reduce the number of separate markets in the US, so that these lines would become internal to a single larger market (as might occur in an all-island market in Ireland).
- The current arrangements for the interconnector to the North, reflecting some level of system operator to system operator agreements that govern the use of the lines.

If Northern Ireland remains a separate market, there is likely scope to change and improve the existing interconnector protocols, but it seems possible that these existing protocols could be adopted into the new Irish market.

[3] In some instances, phase angle controllers and other devices have been installed to help control flows on these lines.

## Appendix D: Prior statements on Interconnection with Northern Ireland

The 21 November 2002 Industry Forum paper included, on page 1-3:

> 'At present the Irish market operates in relative isolation but this may not continue into the future. The arrangements that will be put in place must be viewed in a wider competitive arena. Issues for consideration include:
>
> - The capacity and impact of the existing interconnectors with Northern Ireland and with Scotland through Northern Ireland and the scope for interconnection directly with Wales;
> - The development, use and impact (if any) of interconnectors between the Irish and England and Wales markets;
> - The trading arrangements in Northern Ireland and proposals, as they develop, for complementary all Island markets in electricity and/or gas.'

The Second Options paper, provided on 24 January 2003, included, on page 4-7 and 4-8:

> **Interconnectors**
>
> The Irish electricity market must have the ability to interface with the existing interconnector to Northern Ireland and any new interconnectors (e.g., an East-West interconnector to Wales) system effectively and efficiently. The existing protocols for the interconnector to Northern Ireland may need to be modified. Any market design must accommodate the operation of interconnects. There are two separate options, although an actual interconnect may operate with a combination of the two methods;
>
> - SMO interchange, and
> - Interconnector trader.
>
> **SMO interchange**
>
> In this option, the SMO would manage the interconnector as another part of system operation. An interchange agreement would be reached with the system operator on the other end of the interconnector that would govern this.
>
> This is similar to the system-to-system interchange agreements that are in effect in the US (where different regional markets are now in place on either ends of some interconnectors) and that were in place in Australia prior to the NEM (where both ends of the interconnector are now inside the single market).
>
> This arrangement gives the SMO maximum flexibility to use the interconnector to maintain system security and reliability. It does not, however, allow the market to determine the operation of the interconnector.

**Interconnector trader**

In this option, the rights to trade on the interconnector are auctioned to private parties that gain the rights to trade the interconnector in both markets to maximise revenue and profits. The proceeds from the auction of these rights would be used to recover the capital investment in the interconnector.

This arrangement has the advantage of strong incentives to operate the interconnector to achieve efficient dispatch on both ends of the interconnector. On the other hand, the SMO may have little or no flexibility (unless the Interconnector trader is also a provider of ancillary services) to use the interconnector to maintain system security and reliability.'