ROI INTERFACE STUDY

An Interim Report for the IME Group

Prepared by NERA

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Introduction

The regulatory authorities in the Republic of Ireland (ROI), led by the Commission for Energy Regulation (CER), are in the process of developing new market arrangements for electricity (MAE). The introduction of the MAE in ROI will have major implications for the organisation and efficiency of all-island trade, and hence the performance of the NI and ROI markets.

Key features of MAE

The centre-piece of the MAE will be a mandatory spot market operated by an independent system and market operator (SMO). The SMO will clear the market using a computer programme (the "Market Clearing Engine" or MCE) that sets a different price for injections and withdrawals at each point ("node") on the transmission grid. While all generators in ROI will receive the price at their injection node, all suppliers will pay a uniform "weighted average demand price". The SMO will also issue "Financial Transmission Rights" (FTRs), financial contracts that allow market participants to hedge price differences between injection nodes and the uniform demand price.

This type of "nodal spot market" for electricity, which the CER calls "Locational Marginal Pricing" or LMP, is said to promote (1) efficient operation ("dispatch") of generators, (2) efficient management of demand, and (3) efficient choice of location for new investment in generation and facilities that use energy.

Key features of the NI system and its interconnection

The wholesale market rules in NI are based on nominations of bilateral contracts, with regulated "top-up" and "spill" prices for imbalances. NI is interconnected to ROI by three North-South (N-S) interconnectors, the main Tandragee to Louth 275 kV line, and two smaller 110 kV lines between Strabane and Letterkenny, and Enniskillen and Corraclassy. The cumulative net transfer capacity (NTC) on these three interconnectors ("N-S interconnection capacity") is allocated to the market by annual auction. The NTC is currently restricted to 300 MW from north to south, and 0 MW from south to north, but a system of "superposition" allows trading on the interconnector in excess of the NTC by netting of trades in opposing directions. There are also arrangements in place between SONI and ESB NG ("marginal trading" and reserve sharing) to minimise the costs of dispatching the interconnected systems and maintaining system security.

MAE and Interconnector Trading

While NI remains separate from the ROI market, the impacts of the MAE on NI will be felt through interconnector trading. This Interim Report examines the arrangements for interfacing between the two systems which will best facilitate efficient interconnector trading assuming that NI remains separate from the MAE in ROI.[1]

For all-island trade in electricity, the most significant aspects of the MAE will be those that relate to interconnector trading. The CER's key proposals on interconnector trading are as follows:[2]

- exports to, or imports from, ROI across the N-S interconnector will both be priced at the LMP at the interconnector node, or nodes;
- all traders wishing to export to, or import from, ROI across the N-S interconnector will have to submit offers to the SMO; and
- the SMO will decide whether to accept offers for export to, or import from, ROI across the N-S interconnector, and determine the LMP at the interconnector node or nodes, just prior to real-time.

The CER has left open for discussion whether users of the interconnector will sell their power at the northern or southern ends of the interconnector or at the border, and whether there will be a single "node" for N-S interconnection capacity or a different node for each of the three lines crossing the border. The former is particularly significant since it will influence the way congestion is handled on the N-S interconnector. If users sell their power at the northern end or at the border, congestion on the N-S interconnector will be managed as part of the MAE and users will receive a price determined by conditions within NI. If they sell at the southern end, there will need to be a system of capacity rights to manage congestion on the N-S interconnector and users will receive a price determined by conditions within ROI. The CER has not said whether interconnector users will be able to acquire FTRs to hedge price differences within ROI, or at what cost. Experience suggests that these decisions are important for the efficiency of future trade on the interconnector.

Lessons from Case Studies

Electricity markets in New Zealand and the north-eastern US (New York, New England, and Pennsylvania-New Jersey-Maryland or PJM) have all implemented LMP market designs similar to that being developed for ROI. The experience of these markets provides a number of practical lessons and insights for the MAE.

1 We benefited from the opportunity of discussing interconnector trading issues with the CER while preparing this report, and would like to thank the CER for their co-operation.

2 ***MAE Interconnector Trading Principles***, CER 03/266, 17th October 2003.

Market rules need to address boundary problems that arise in LMP markets

In New York, scheduling and curtailment of imports and exports of electricity created problems that resulted in price differentials across boundaries and sub-optimal use of transmission capacity. The difficulties encountered prompted, in part, the introduction of day-ahead markets in New York and the other north-east US markets.

This experience shows that a failure to integrate the design of efficient interconnector trading arrangements into the overall design of an LMP market will cause significant problems and inefficiencies at the boundaries with other markets. These inefficiencies raise costs and distort market outcomes on both sides of the boundary.

Boundary issues have yet to be fully identified and resolved within the detailed MAE design.

Regulatory measures to control the conduct of dominant players can depress market prices

In response to price spikes in New York in 2000, the regulator intervened and created market power mitigation rules (known as "Automated Mitigation Plan" or AMP). They operate by automatically over-riding a generator's offer if certain pre-conditions are met. There is some evidence that these rules have had the unintended effect of depressing market prices below the levels needed to remunerate new investment in generation.

The CER proposes to introduce a number of market power mitigation measures alongside LMP, which creates a risk of a similar outcome in ROI.

FTRs are an essential pre-requisite to the efficient operation of an LMP market

In New Zealand, where there are a number of incumbents that are vertically integrated on a regional basis, the transmission company is not making FTRs available to the market in spite of Government urging. The absence of FTRs in the New Zealand market is ***both*** a product ***and*** a cause of vertical integration among the incumbents. They have little incentive to lobby for FTRs, since they face little risk of price differences due to producing power in one place and selling in another; without FTRs, the incumbents manage this risk by vertical integration and market partitioning. The lack of FTRs in the New Zealand market represents a barrier to entry that has had a negative impact on competition.

The CER has made no firm commitment to make sufficient FTRs available to interconnector users, nor given any indication of the terms on which they would be offered.

Pre-requisites for efficient cross-border trade

This experience of LMP markets highlights certain essential pre-requisites for efficient cross-border trade between the interconnected NI and ROI markets. To maintain efficient, least-cost operation of existing power stations and demand, the market must:

1. promote efficient co-ordination of ***third party*** cross-border trade ahead of real-time up to gate closure; and

2. allow efficient ***system-to-system*** trade between the NI and ROI system operators (SOs) after gate closure and in real-time.

The first point is essential in order to avoid exposing traders to unnecessary risks that would deter them from trading over the interconnector. The second is essential to ensure that the costs of dispatching the interconnected NI and ROI systems and maintaining system security are minimised.

The other pre-requisites for efficient cross-border trade are:

3. the definition of the N-S interconnector node or nodes must take into account the physical realities of the NI and ROI electricity systems, so that cross-border trade is efficient and does not unnecessarily raise the costs of operating the interconnected NI and ROI systems;

4. interconnector users must be able to acquire (i) contracts with suppliers (e.g., "contracts for differences" or CfDs), to hedge variations in LMPs over time at some reference node, and (ii) FTRs, to hedge volatility in the difference between LMPs at that reference node and those at the interconnector node(s).

Unless the new arrangements for interconnector trading under the MAE meet these pre-requisites, they will damage the efficiency of all-island trade, with negative consequences for costs and prices in NI and ROI.

Risk of MAE having an adverse impact on cross-border trade

At present, generators and suppliers in NI, and traders wishing to send power across the Moyle interconnector into NI (for use in NI or for transit to ROI), have to submit nominations to SONI by 11:00 hours on the day before the day of delivery (a time defined as "NI gate closure"). These nominations represent a firm commitment to provide (or consume) power, or else to face a penalty. However, the CER proposes to treat nominations made in NI for exports to, or imports from, ROI as "offers" which the ROI's market may either accept or reject. The CER's proposals for interconnector trading arrangements will expose interconnector users to the risk of a "mis-match" between their nominations in NI and the offers accepted by the SMO just prior to real-time. In the event that there is a mis-match, NI and Moyle traders using the N-S interconnector would be exposed to punitive imbalance charges within NI.

NI and Moyle traders can minimise the risk of a "mis-match" by adopting offering strategies that ensure their offers are accepted by the SMO. For example, NI and Moyle traders who wish to export to ROI might submit zero price offers to the SMO. However, while that would reduce the risk of a "mis-match", it may result in lower LMPs at the interconnector node(s) when the interconnector is congested. For that reason, NI and Moyle traders will face a trade-off between the risk of LMPs that are too low, and the risk of a “mis-match” exposing them to imbalance charges in NI.

These risks might be reduced by moving NI and Moyle gate closure closer to real-time, but that would impose costs on NI market participants (who have made investments based on the current rules), and would not remove the risks fully. The simple, low-cost way to do that would be for the CER to design a market that accepts all nominations on the interconnector as commitments to export power to, or import power from, ROI at the prevailing nodal spot price (i.e. a market that recognises the inflexible status of prior nominations). This approach would avoid imposing unnecessary risks on nominations by traders made before NI gate closures. It should also be extended to “marginal trades” arranged by the two system operators, during the period between NI gate closure and the ROI equivalent (one hour in advance of delivery). An alternative would be for ROI to introduce a day-ahead market (following the lead of the north-east US LMP markets), to allow the SMO to decide whether to accept or reject offers for export to, or import from, ROI ***before*** NI gate closure, but that is less simple than treating nominations as the commitments that they truly represent.[3]

A rule that recognises the inflexible status of nominations would not have any adverse effect on the efficiency of all-island dispatch under the MAE provided that there is a mechanism in place, such as the present system of “marginal trading”, to ensure efficient system-to-system trade in real time. The CER has not yet made any proposals on what system, if any, would replace “marginal trading” under the MAE, but it is, as we have already noted, an essential pre-requisite for efficient cross-border trading.

Other risks associated with the proposals for MAE in their current form include the following:

- Some aspects of the CER’s proposals run the risk of depressing LMPs in general, and those at the N-S interconnector node(s) in particular, below equilibrium competitive levels (in particular, below the full cost of new generation capacity). Depressed prices would have a negative impact on the extent of trade from NI to ROI, which would in turn raise the prices charged to franchise customers in NI, since NIE PPB would face a loss of export revenue.

- The absence of any proposals for structural changes to deal with the dominance and vertical integration of ESB faces other market participants with the risk that it will be difficult to get access to contracts with suppliers and FTRs, for the same reasons as independents have found it difficult to access these contracts in New Zealand. Difficulty in accessing contracts and FTRs would make it hard for interconnector

[3] Were NI eventually to integrate with the ROI market, an arrangement like this would probably be required to manage the interface between an integrated all-island market and the GB market, which, under BETTA, will be based on nominations of bilateral contracts.

users to hedge against price volatility at the interconnector node(s) and deter them from trading across the N-S interconnector.

- The CER's proposal to charge the costs of reserves "to those market participants who cause them" runs the risk of charging interconnector users the costs of reserves even though they have no direct control over interconnector flows.

It is worth noting that in its current form, the MAE poses no additional risks to renewable generators and suppliers in NI, other than those already identified above. But maintaining the current system for imports of green energy from ROI, which involves a two week lag between output by green generators in ROI and the corresponding nominations on the N-S interconnector, would require a procedure for registering these transactions under the MAE.

Recommendations for an efficient interface

Interconnector trading raises a range of concerns, most of which would be alleviated by relatively straightforward amendments to the CER's proposals for the implementation of the MAE. These amendments would ensure that the MAE satisfies the pre-requisites for efficient all-island trading, while avoiding the other risks identified above. Our recommendations, which are based on achieving efficient arrangements without major re-negotiation of NI trading rules and contracts, are as follows:

- to ensure efficient co-ordination of third party trades prior to real-time, the MAE should recognise nominations to send power over the interconnector as commitments to deliver power at the spot price at the southern end of the interconnector;

- to ensure efficient dispatch of the NI and ROI interconnected system in real-time, the MAE should accommodate the current system of "marginal trading" between system operators, in some form or other;

- the CER must ensure that interconnector users have access to FTRs between the interconnector node or nodes and the uniform demand price;

- the CER must ensure that interconnector users have access to contracts with suppliers by making sure there is a liquid contracts market;

- the CER should exempt interconnector users from paying for the costs of reserves caused by the operation of the N-S interconnector, since they have no control over the way it is operated and cannot respond efficiently to such price signals. Any imbalances or errors in flows over the interconnector should be handled through inter-SO settlement; and

- the point of sale for nominated trades over the NI-ROI interconnector should be restricted to the node corresponding to the main 275 kV interconnector between NI and ROI (since the 110 kV interconnectors are needed to provide mutual system support in emergency conditions);

- the existing reserves sharing arrangement between the NI and ROI systems should be accommodated by the MAE.

In addition, we strongly recommend that the CER should avoid measures which have the unintended effect of depressing spot market prices in ROI below the levels needed to remunerate new investment. Such measures would not only have an adverse impact on franchise customers in NI, but would also harm investment incentives and security of supply on the island as a whole.

Next steps

NI's electricity system has a number of specific problems with the CER's proposals, which result from it being situated at one extremity of the ROI transmission system. Many of these problems might not be apparent from examining the ROI market as a whole, but some raise issues of general concern for the efficiency of all-island trade and hence the ROI market itself. The concerns raised by the interface between ROI and NI merit detailed consideration by the CER, both to address NI's legitimate interests and to ensure that the CER's proposals do not diminish the efficiency of all-island electricity trading.

In the next phase of our work, we will examine the question of whether the NI market should integrate with the MAE to form a single all-island market, based on an appraisal of whether this would give a better result for NI customers and for all-island trading generally. As part of that work, we will be considering in greater detail issues such as:

- the proposed new arrangements for managing ESB's dominant position in the ROI market;
- the CER's proposals for vesting contracts to control ESB's market power, and the possible unintended effects of these contracts;
- the effects of the CER's proposal to institute a Fast Build Agent to ensure generation adequacy in ROI;
- the detailed design of the MAE market rules; and
- interface issues between an integrated all-island LMP market and a GB market operating under BETTA.

1. INTRODUCTION

The regulatory authorities in the Republic of Ireland (ROI), led by the Commission for Energy Regulation (CER), are in the process of developing new market arrangements for electricity (MAE). The introduction of the MAE in ROI will have major implications for the organisation and efficiency of all-island trade, and hence the performance of the Northern Ireland (NI) and ROI markets.

The purpose of our study is to assess what the impacts of the MAE are likely to be on NI and to advise the IME Group on how NI should respond. In this Interim Report, we have looked at these questions in a scenario in which the NI market remains separate from the ROI market. Later, in our Final Report, we will examine the question of whether the NI market should integrate with the MAE to form a single all-island market.

To inform our appraisal, we have carried out modelling of the ROI and NI markets, and done case studies of the electricity markets of New Zealand and the north-east US markets of New York, New England, and PJM, all of which have implemented market designs similar to the MAE.[4]

The rest of this report is organised as follows:

- Chapter 2 presents some background information on the MAE, and current market arrangements in NI and on the North-South and Moyle interconnectors;
- Chapter 3 summarises the key lessons from our case studies;
- Chapter 4 discusses the implications of the CER's proposals for interconnector trading under the MAE, and makes recommendations on how these proposals can be developed to avoid adverse impacts on all-island trade; and
- Chapter 5 summarises the implications of the MAE in its current form for NI.

[4] "PJM" stands for Pennsylvania-New Jersey-Maryland, which have combined to form a single electricity market spanning all three states.

2. BACKGROUND

2.1. Introduction

In this chapter, we provide a brief overview of:

- the MAE being developed for the ROI electricity market;
- the current NI market arrangements; and
- the current interconnector trading arrangements.

This provides necessary background to the discussion that follows in later chapters of the implications of the MAE for interconnector trading and the NI market.

2.2. Republic of Ireland

2.2.1. The MAE

The high-level principles of the MAE are laid down in ministerial regulation S.I. 304.[5] The centre-piece of the MAE will be a "nodal spot market" for electricity, which the CER calls "Locational Marginal Pricing" or LMP.

LMP markets exist in various guises in a number of other jurisdictions, including New Zealand and the northeastern US markets of New York, New England, and Pennsylvania-New Jersey-Maryland (PJM). While the operation of LMP markets is well understood in these other jurisdictions, it will be less familiar to a European audience. For that reason, in Appendix A we provide a summary of how a generic LMP market works.

In terms of the design of the spot market under the MAE, the main principles laid down by S.I. 304 are summarised in Box 1.

To support the efficient operation of the spot market under the MAE, S.I. 304 also requires the CER to introduce financial transmission rights (FTRs) to allow market participants to hedge locational price differences under the proposed LMP market.[6]

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[5] ***S.I. No. 304 of 2003, Electricity Regulation Act 1999, (Market Arrangements for Electricity) Regulation 2003.***

[6] The way in which FTRs work is explained in Appendix A.

Box 1: The Design of the ROI Spot Market under the MAE

The spot market will be a mandatory gross pool operated by an independent system and market operator (SMO). The spot market will be mandatory in the sense that all generators are obliged to sell, and all suppliers (or customers acting as suppliers) are obliged to buy, all their electricity on the spot market.

The SMO will clear the market using a computer programme (the "Market Clearing Engine" or MCE) that sets a different price for injections and withdrawals at each point ("node") on the transmission grid. While all generators in ROI will receive the LMP at their injection node, all suppliers will pay a uniform "weighted average demand price", irrespective of the location of their demand.

The SMO will clear the spot market and dispatch the system simultaneously. The SMO will dispatch and operate the ROI power system in accordance with the spot market rules, the grid code, and other operational procedures.

The SMO will be responsible for settlement of spot market trading. Settlement will be on the basis of the gross quantities traded through the spot market. The SMO will take no account of any financial hedging contracts (e.g. contracts-for-differences, or CfDs) between generators and suppliers in the settlement process.

The spot market will be an electricity, or energy, only market. There will be no side payments for unit start-up, shut-down, etc. and no separate capacity payments.

A supplier can elect to define part of its demand as dispatchable. A supplier is required to offer its dispatchable demand into the market.

The SMO will operate a spot market for operating reserves in parallel with the energy spot market. The SMO will clear these markets simultaneously to ensure that the joint cost of meeting demand in these markets is minimised. Other ancillary services will be procured by the SMO under long-term agreements.

2.2.2. ESB market dominance

ESB currently occupies a dominant position at both the generation and retail levels in the ROI market.[7] While the MAE will fundamentally change the rules that govern the operation of the ROI electricity market, it does not include any proposals to restructure ESB to dilute its market dominance.

[7] ESB's market share at both the generation and retail levels is well above the 50% threshold level at which there is a presumption of dominance under European Community competition law (cf. ***AKZO v Commission***, Case C-62/86 [1991] ECR I-3359).

2.2.3. Market opening

Following the entry into force of Directive 96/92/EC,[8] eligible customers in ROI were given the right to purchase their electricity supplies from any licensed supplier. Eligible customers are currently defined as those with an annual consumption in excess of 1 GWh. Table 2.1 shows past and prospective steps in the opening of the electricity market to competition.

Table 2.1
Market opening in the Republic of Ireland

Opening Date	% of Market Opened	Consumption Required to be Eligible customer	Number of Eligible Customers
February 2000	28%	> 4GWh p.a.	400
February 2002	40%	> 1GWh p.a.	1,600
2005	100%	Any	1.6 million

Source: CER press release, 31st July 2003.

2.3. Northern Ireland

2.3.1. Wholesale market rules

The current wholesale market rules in NI are based on scheduling and dispatch of bilateral contracts.[9] Under these rules:

- generators must make nominations to System Operator Northern Ireland (SONI) for each of their generating units for a trading day by 11:00 hours on the previous day ("NI gate closure");
- after NI gate closure, generators cannot change their nominations without the consent of SONI; and
- generators are charged for imbalances at regulated "top-up" and "spill" prices.

A full summary of the current wholesale market rules in NI is contained in Appendix B.

2.3.2. Market opening

Under the arrangements put into place at the time of privatisation in NI, all customers were free to choose their supplier, but all suppliers had to buy their power from NIE's power procurement business (NIE PPB) at a regulated bulk supply tariff (BST). Following the entry

[8] European Parliament and Council Directive 96/92/EC of 19 December 1996 concerning common rules for the internal market in electricity. OJ L 27, 30.1.1997, p. 20.

[9] ***Interim Settlement Code, version 3.0***, 26th March 2003.

into force of Directive 96/92/EC, some customers ("eligible customers") were given the right to purchase their electricity supplies at negotiated prices independent of the BST.

Currently in NI, all customers with an annual consumption of over 0.79 GWh are defined as eligible. The eligible market in NI currently represents 35% of consumption.

The Department of Enterprise, Trade and Investment (DETI) plans to extend electricity market opening in NI as follows:

- to all non-domestic consumers on a phased basis commencing April 2004, representing 60% of the market; and
- to all consumers by July 2007.

Any customer in NI is eligible to buy electricity from "green energy" suppliers, including NIE PPB.

2.3.3. Prices to franchise customers

Suppliers who sell to non-eligible customers, or "franchise customers", in NI still have to buy their power from NIE PPB at the regulated Bulk Supply Tariff (BST). The BST is set at a level that allows NIE PPB to recover its costs of purchasing power under long-term agreements with generators, after netting off any non-BST sales to the independent sector in NI or in the form of exports.[10] Since NIE PPB's non-BST sales make a contribution to meeting the fixed availability payments in its long-term agreements with generators, higher non-BST sales benefit franchise customers in NI through a lower BST.

2.3.4. Renewables and CHP

Several initiatives are intended to promote the use of renewables in NI:

- ***Climate Change Levy Exemption***: Electricity production from renewables is exempted from the Climate Change Levy.[11] Also, renewables do not pay the transmission use of system charge. These exemptions are equivalent to a 0.8p/kWh subsidy for renewables.[12] Combined Heat and Power (CHP) plants are also exempt from paying the Climate Change Levy, which is approximately equivalent to a subsidy of 0.5p/kWh.

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[10] NIE's Power Procurement Business, Final proposals papers – Price Control Final Proposals issued by the Director General of Electricity Supply (NI) for the period April 2002 – March 2005, July 2002. Under its current price control, NIE PPB is allowed to earn 0.02p/kWh on BST sales and 0.12p/kWh on non-BST sales to give it an incentive to maximise its non-BST sales.

[11] There is also an exemption for Natural Gas until 2006.

[12] Competition and Customer empowerment: the next steps in the Northern Ireland Market – A consultation paper by the Director General of Electricity supply, March 2003.

- ***Non Fossil Fuel Obligation (NFFO) for NIE***: NIE PPB is required to purchase specified amounts of electricity from renewables. As a result, NIE PPB has contracts with 32 MW of renewable generation capacity. The excess costs of meeting this obligation are recovered through a public service obligation (PSO); and
- Wind energy, provided under the renewable obligations factor (ROF) scheme, has a special support arrangement to avoid price fluctuations linked to weather conditions. Wind generators provide NIE PPB with 120% of their demand over the course of a year. In exchange, these generators do not need to pay any extra top up charges when production fails to meet demand in real-time, with NIE PPB providing the top-up supply.

2.4. Interconnectors

NI is interconnected to the ROI through the North-South interconnector, and to Scotland through the Moyle interconnector.

2.4.1. North-South interconnector

There are three AC interconnectors linking NI to the ROI, one 275 kV line and two 110 kV lines. The main 275 kV interconnector runs between Tandragee (NI) and Louth (ROI). It was restored to service in 1995, after being out of service for a long period. During 2001, it was upgraded from 2x300 MW circuits to 2x600 MW circuits.[13]

The two 110 kV interconnectors run between Strabane (NI) and Letterkenny (ROI), and Enniskillen (NI) and Corraclassy (ROI). These interconnectors were commissioned in 1994 as standby links, primarily to allow the NI and ROI system operators to provide mutual assistance in emergency. They were not, therefore, built for cross-border trading. They were also upgraded in 2001 to "full system interconnectors" with a capacity of 120 MW each.[14]

Under the current arrangements, the Available Transfer Capacity (ATC) of the North-South interconnectors is divided into "Net Transfer Capacity" (NTC), which is made available to the market for third party trade, and the "Transmission Reliability Margin" (TRM), which is used by the SOs to provide reserve to one another. The NTC on the North-South interconnectors is currently limited to 300 MW from North to South and 0 MW from South to North. This total NTC applies jointly to all three AC interconnectors. The SOs decide jointly how to use each of the interconnectors to transfer the net volume of nominated trades. Physical power flows over the two 110kV interconnectors are normally set to zero. In practice, therefore, the actual power flow between NI and the ROI takes place over the main 275kV interconnector between Tandragee and Louth.

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[13] ESB press release, NIE ***and ESB Grids Make a Powerful Connection***, 10th April 2002

2.4.2. Moyle interconnector

The Moyle interconnector is a 500 MW DC link that was officially commissioned on 16 April 2002. The available transfer capacity (ATC) of the Moyle interconnector is limited to 400 MW due to system constraints. Since April 2003, the Moyle interconnector has belonged to Moyle Holdings Limited,[15] a not-for-equity-distribution company, whose members and directors have been nominated by Team Northern Ireland,[16] Ofreg and other interested parties.

NIE PPB has contracted for 125 MW of Moyle import capacity until 2007 to allow it to honour its contract with Scottish Power (SP) to import 1,000 GWh per year for a period of five years and 10 months.[17, 18] NIE PPB sells on the energy it acquires from SP under this contract to "second tier" suppliers through the Moyle Equivalent Energy (MEE) auctions.[19]

The rest of the ATC on the Moyle interconnector (known as the "net ATC" because it is net of the 125 MW of capacity already allocated to NIE PPB) is offered to third-parties by auction.

2.4.3. Third-party trade on the interconnectors

Until recently, third-party trade on the North-South and Moyle interconnectors was governed by a similar set of rules. These involved long-term capacity allocation through annual auctions of a range of physical interconnector products, and a common set of rules governing nominations and settlement of daily flows.

In April 2003, however, superposition was introduced on the North-South interconnector. (See section 2.4.3.2 for an explanation of superposition.) The introduction of superposition has necessitated some changes to the rules governing nominations and settlement on the North-South interconnector, although auctions of long-term capacity have been retained.

Below we summarise the arrangements concerning long-term capacity allocation and nominations and settlement of daily flows.

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14 ESB press release, NIE ***and ESB Grids Make a Powerful Connection***, 10th April 2002

15 See Viridian press release, VIRIDIAN GROUP PLC – DISPOSAL OF THE MOYLE INTERCONNECTOR, 14 April 2003

16 Team Northern Ireland is a private sector initiative established to increase infrastructure investment in Northern Ireland.

17 Power UK Issue 57, 27/11/1998 Interconnector gets green light.

18 The contract price was originally 2.1 p/kWh, indexed to inflation and coal prices.

19 PPB offered 1, 2 and 3 year MEE contracts at the last auction.

2.4.3.1. *Long-term capacity allocation*

The NTC on the North-South interconnectors and the net ATC on the Moyle interconnector is made available to the market through annual auctions. In December 2002, the following capacities for 2003/4 were available through auction: (1) 225 MW of winter and summer day capacity and 125 MW of summer night capacity were auctioned on the Moyle interconnector, 50 MW of which was interruptible capacity; and (2) 300 MW of export capacity was auctioned on the North-South Interconnector, although only 190 MW was taken up.

Capacity was divided among the following products:

- One, two and three year Moyle import (Scotland-NI);
- One year Moyle export (NI-Scotland);
- Moyle interruptible; and
- One year North-South export.

Interconnector capacity for 2003/4 was divided equally into two auctions held seven days apart, with arrangements for capacity unsold at the first auction to be made available at the second auction and with arrangements for subsequent auctions if any capacity was left unsold. Successful bidders paid their bid price for capacity. Reserve prices were set for all products.

2.4.3.2. *Nominations and settlement*

A summary of the rules governing nominations and settlement on the North-South and Moyle interconnectors is contained in Appendix B. We list below some of the key aspects of these rules:

- North-South interconnector
  - market participants ***do not*** require long-term capacity rights in order to be eligible to make nominations on the North-South interconnector, but the nominations of those that have acquired long-term rights through the capacity auctions (see above) are given precedence over those that have not in the daily capacity allocation process;
  - interconnector parties on the North-South interconnector must make import or export nominations for a trading day by 12:00 hours on the day two days before the trading day (i.e. North-South gate closure is 23 hours before gate closure for trade within NI);
  - superposition on the North-South interconnector allows trading on the interconnector in excess of the physical limits on flows of electricity by

netting of trades in opposing directions; traders can submit additional nominations at any time up to North-South gate closure, as long as the resulting net total nomination is within the NTC;

- interconnector parties who are allocated a trade in excess of their long-term capacity rights are subject to an interconnector usage charge;

- Moyle interconnector
  - market participants must acquire long-term capacity rights through the capacity auctions (see above) in order to be eligible to make nominations on the Moyle interconnector;
  - capacity holders on the Moyle interconnector must make import or export nominations to SONI for a trading day by 11:00 hours on the previous day (i.e. Moyle gate closure is the same as gate closure for trade within NI);
  - the nominations of capacity holders on the Moyle interconnector must not exceed their entitlements (i.e., no superposition is allowed).

There is also a special arrangement in place to facilitate trade in energy from renewable sources across the North-South interconnector. Under this arrangement, suppliers in NI are able to nominate imports of green energy generated two weeks earlier, thus avoiding the risk of imbalances caused by unpredictable fluctuations in the availability of wind generation, the main source of renewable energy in the ROI.

2.4.4. SO-SO trading on the North-South interconnector

On the North-South interconnector, the SOs co-operate to arrange "special trades" and "marginal trades".

- Special trades

Special trades are forward sales of energy between NIE PPB and ESB PG, which are facilitated by the SOs acting as agents. Sometimes NIE PPB sells power to ESB PG through a special trade, and sometimes NIE PPB buys power from ESB PG.

Normally, a special trade is for a firm supply of power between NIE PPB and ESB PG. The recently announced deal for NIE PPB to supply ESB PG with 180 MW of capacity over a three year period is a slightly different type of special trade.[20] Under this deal, ESB PG has an option to call or operate the 180 MW of contracted capacity according to its needs.

[20] NIE press release, ***Boost for the Integrated Electricity Market***, 18/07/2003

- Marginal trades

"Marginal trades" are real-time trades between the SOs in NI and ROI which take place based on marginal trading prices fixed for four-hour trading intervals. The marginal trading prices are fixed on the basis of the "merit orders" (i.e. the ranking of power stations in order of variable operating cost) in NI and ROI. Currently, the merit order for NI is based on the energy prices determined under NIE PPB's long term PPAs, and the merit order for the ROI is based on the marginal costs of ESB PG's generating units.

The SOs can only arrange marginal trades if there is spare physical capacity on the interconnector after all third parties have exercised their rights to nominate power flows.

The SOs settle the actual power flow between them (net of third party nominations) on the basis of marginal trading prices agreed in advance, by splitting the profit on each trade (i.e., the difference between each other's marginal trading price).

2.4.5. Allocation and trading of operating reserves

Operating reserve requirements in NI and ROI are based on all-island parameters. Some of the capacity on the interconnectors is reserved so that in contingencies reserves or power can be transferred between NI and ROI in certain conditions. There is currently no arrangement for short-term trading of operating reserves.

3. CASE STUDIES

3.1. Introduction

To inform our appraisal of the MAE, we have studied the electricity markets of New Zealand and the north-eastern US markets of New York, New England, and PJM, all of which have implemented market designs similar to the MAE. We chose to look at the experience of these particular markets for the following reasons:

- North-east US:
  - recent transitions to LMP,
  - LMP jurisdictions trading with LMP and non-LMP jurisdictions across interconnectors, and
  - each of the three jurisdictions had slightly different approaches to implementation;
- New Zealand:
  - early adopter of LMP (known locally as full nodal pricing, or FNP), and
  - widely cited as an example of LMP (including by the CER).

3.2. Key Lessons

We set out below the lessons we draw from our case studies that are relevant to the situation where NI remains separate from the ROI market.

- Market rules need to address boundary problems that arise in LMP markets

In New York, scheduling and curtailment of import and export of electricity have created problems that have resulted in price differentials across boundaries. Price differentials have persisted, are difficult to predict and have been volatile. Price differentials can result in sub-optimal transmission system utilisation and prevent participants from fully hedging the costs of transmission usage for inter-regional transactions. Also, the inefficiency of trade across boundaries can promote gaming (e.g., in an attempt to reduce interconnector charges).

The difficulties encountered by the US markets prompted, in part, the introduction of day-ahead markets, and have created an impetus for merger of these markets and for other improvements in trading arrangements.

- Regulatory measures to control the conduct of dominant players can depress market prices

In response to price spikes in New York in 2000, the regulator intervened and created market power mitigation rules. These rules (known as the Automated Mitigation Plan or, AMP) have as their objective the detection and mitigation of market power before the fact. They operate by automatically over-riding a unit's offer to the Independent System Operator (ISO) if certain preconditions are met. There is some evidence that these rules have had the unintended effect of depressing market prices below the levels needed to remunerate new investment in generation.

- FTRs are an essential pre-requisite to the efficient operation of an LMP market

In New Zealand, where there are a number of incumbents that are vertically integrated on a regional basis, the transmission company is not making FTRs available to the market in spite of Government urging. The absence of FTRs in the New Zealand market is ***both*** a product ***and*** a cause of vertical integration among the incumbents. They have little incentive to lobby for FTRs, since they face little risk of price differences due to producing power in one place and selling in another; without FTRs, the incumbents manage this risk by vertical integration and market partitioning in the New Zealand market. The lack of FTRs in the New Zealand market represents a barrier to entry that has had a negative impact on competition.

3.3. Summary

Integration of LMP markets with neighbouring (non-LMP) markets has proven difficult and a potential source of inefficiency. However, the interests of incumbents have sometimes led to the problems of new entrants and neighbouring systems being sidelined. The treatment of interconnectors can therefore help to highlight issues important for efficient competition.

4. ISSUES IN INTERCONNECTOR TRADING

4.1. Introduction

As long as the NI market remains separate from the ROI market, it will be crucial to ensure that arrangements for trading across the North-South interconnectors are efficient and adapted to the specific conditions of the two markets. The efficient arrangement of cross-border trade is particularly important for the two electricity markets within Ireland, since they are small markets in which the interconnectors play a major role in both energy trading and the maintenance of system security.

Experience in the US shows that a failure to integrate the design of efficient interconnector trading arrangements into the overall design of an LMP market will cause significant problems and inefficiencies at the boundaries with other markets. These inefficiencies raise costs and distort market outcomes on both sides of the boundary.

In this section, we discuss the options and proposals put forward by the CER, as well as alternatives to these proposals.

4.2. CER's Proposals

4.2.1. Second Options Paper

In January 2003, the CER published a "Second Options Paper", written by PA Consulting Group,[21] which described two possible interconnector trading arrangements.

The first option, called "SMO Interchange", would give the SMO (the System and Market Operator of the ROI) the exclusive right to manage the interconnector under an interchange agreement with SONI. The CER noted that this option would give the SMO maximum flexibility to use the interconnector to maintain system security, but it would not allow the market to determine how the interconnector is used.

The second option, which the CER called "Interconnector Trader", would involve auctioning the right to trade over the interconnector between the ROI and NI markets. The CER noted that this would provide strong incentives for efficient operation of the interconnector, but might also restrict the SMO's ability to use the interconnector to maintain system security.

However, the CER also noted that these two possibilities are not mutually exclusive and a combination of the two could be used on the same interconnector.

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[21] PA Consulting Group (2003), ***Irish Electricity Trading Arrangements: Second Options Paper***, Commission for Electricity Regulation, 24 January 2003.

4.2.2. Interconnector Forum (22 September 2003)

At the recent North-South Interconnector Forum, organised jointly by the CER, Ofreg and the two SOs, the CER outlined some proposed arrangements for trading on the North-South interconnectors. The key slide, entitled "Principles Trading at the Interconnector", says (verbatim):

- "Offering across Interconnector to and from MAE
    - Exports from MAE (Demand Offers)
    - Imports to MAE (Generation Offers)
- Participants could offer directly or agent or perhaps SMO / Interconnector trader with some capacity allocation mechanism?
- MAE Pricing & Dispatch at the Interconnector
    - Nodal Price for generation and demand offers".

At the Forum, the CER also highlighted that the choice of trading arrangements for the North-South interconnectors may have "implications for other issues", including:

- gate closure;
- financial transmission rights (FTRs); and
- the continuation of existing schemes, in particular super-position.

The slides are hard to interpret without a verbal explanation, but the following sections attempt to provide an interpretation of the implicit principles.

4.2.3. The CER's Consultation Paper on Interconnector Trading

The CER has clarified some of its proposals on interconnector trading in a consultation paper issued on 17th October 2003.[22] This consultation paper lists three options for market trading on interconnectors, as follows:

- Option 1: Economic Dispatch at the Interconnector (Implicit Rights only);
- Option 2: Economic Dispatch with Capacity Rights (Explicit Rights); and
- Option 3: Economic Dispatch with Use-it-or-lose-it capacity rights (Explicit & Implicit Rights combined).

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[22] ***MAE Interconnector Trading Principles***, CER 03/266, 17th October 2003.

The consultation paper makes clear that under all three options, the CER proposes that exports and imports across the interconnector will be dispatched based on generation and demand offers into the MAE, and the prices of exports and imports will be based on the relevant LMP price.

Compared to its earlier statements on interconnecor trading, the CER has dropped references to SMO interchange as an option for the organisation of interconnector trade, but that concept remains intrinsic to the "use-it-or-lose-it" aspect of Option 3, where the system operators would take over the right to use any spare capacity after a certain time.

4.3. Clarification of the CER's Proposals

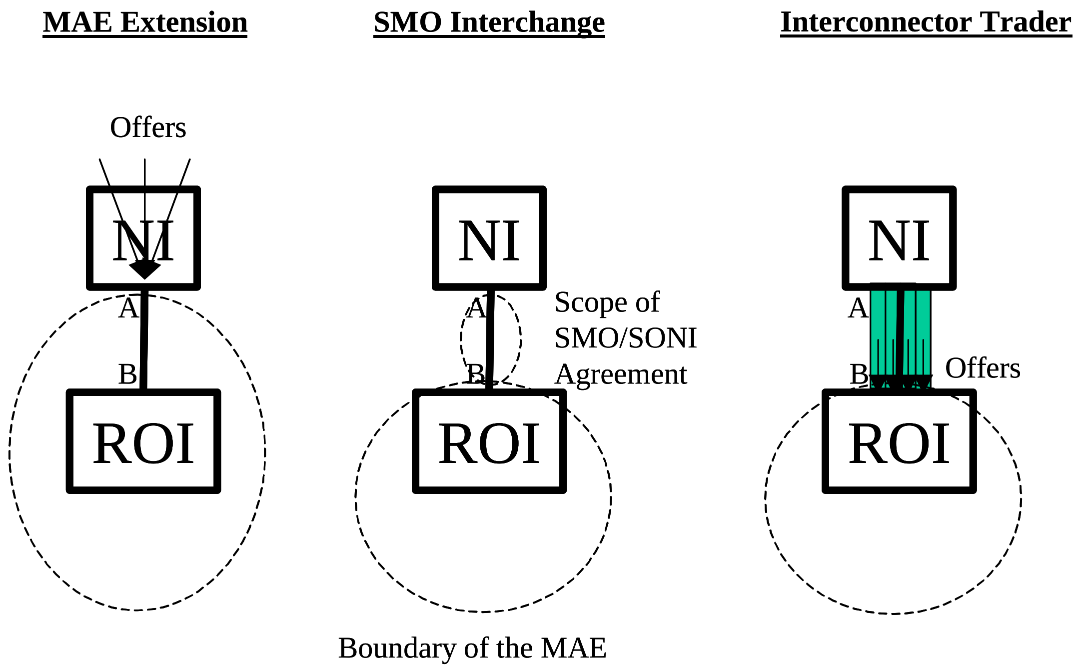
The CER has framed its options and proposals for the interconnector at a high level, and without more detail it is difficult to assess fully what their implications will be. Figure 4.1 below provides a possible interpretation of the different schemes that have been proposed by the CER. It describes two electricity market (NI and the ROI) linked by a single interconnection, where node A represents the northern end(s) of the interconnectors and node B represents the southern end(s).

The first scheme, which we label the "MAE Extension", seems to involve an extension of the MAE into NI (or at least up to the border), so that producers and traders inside NI can offer electricity directly to the market at node A, or at some point between A and B such as the border. This approach seems to treat the interconnector (or at least the ROI part of it) as just another part of the transmission system operated by the SMO. It represents a close proxy to systems already developed for LMP markets in the US, which set up one "external node" for each interface with neighbouring systems; the capacity available to move power to and from such "external nodes" corresponds to interconnection capacity between the systems.

This first scheme corresponds most closely to what the CER called Option 1 in its latest consultation paper.

The second scheme, which the CER has labelled "SMO Interchange", seems to leave the two system operators, the SMO and SONI, to arrange trade between nodes A and B.

Figure 4.1
Possible Interpretations of CER Options



The third scheme, which the CER originally labelled "Interconnector Trader", involves some kind of physical transmission rights (PTRs) over interconnector capacity (shown here as four blocks between nodes A and B). Traders would acquire capacity through a capacity allocation mechanism (e.g. an auction) that has yet to be specified. Traders holding such interconnector capacity would offer power directly into the ROI's market at node B, the ROI end of the interconnector.

This last scheme corresponds most closely to what the CER called Options 2 or 3 in its latest consultation paper, the only difference between those Options being that Option 3 allows for "SMO Interchange" after a certain time, under the "use-it-or-lose-it" rule.

Each of these schemes raises a number of questions for clarification and potential concerns, as explained below.

4.3.1. MAE Extension

At no point does the CER talk explicitly about extending the MAE to the northern end of the interconnectors or to the border, but that seems to be the implication of any scheme where "participants" can offer directly into the ROI market, and yet do not have rights to interconnector capacity. Market participants inside Northern Ireland could only submit offers to buy and sell power on the northern side of the interconnector and the SMO would decide which to accept. In essence, this procedure would allocate capacity on the interconnector within the process of dispatch and no-one would have any long-term (physical) rights to use it.

The CER does not say specifically whether accepted offers would earn (or pay) the nodal price at the northern end of the interconnector or at the southern end. However, there could be a big difference between the two prices. Whenever the interconnector was congested (i.e. fully utilised), a nodal LMP price at the northern end would reflect conditions inside Northern Ireland. The gains from cross-border trade would be retained within the MAE's financial surplus and would not be uniquely defined, since there would be no nodal price at the southern end of the interconnector to compare with the price at the northern end. SONI would still be able to extract such gains by charging the SMO for its use of the interconnector within the MAE, but would have to estimate the scale of the benefits in advance. Alternatively, the agreement between SONI and the SMO might define the benefits to be shared as the volume of exports/imports multiplied by the difference between the nodal price at A and the nodal price at some other node (e.g. a node near the interconnector, or the customer demand node).

The main problem with this approach is the incompatibility of the MAE timetable with gate-closure inside Northern Ireland. Traders would find it difficult to arrange a schedule of electricity production or purchases to match the offers that MCE happened to accept in the hour before a trading interval. Similar problems have arisen in the US markets which have tried this form of interface between markets. To avoid similar problems, adoption of this approach would require either an amendment to the trading rules inside Northern Ireland, or a special bidding process for interconnectors in the ROI market, to allow closer integration of scheduling north and south of the border.

In practice, it will be difficult to accommodate real-time bidding in the ROI market with any advance scheduling process inside Northern Ireland, without exposing traders to the risk of significant mis-matches and the associated imbalance penalties. There is therefore a limit to what NI market participants can achieve by amending the NI market rules (short of full integration).

4.3.2. SMO Interchange

This proposal appears to be similar to current arrangements for the use of spare capacity close to real time (i.e. the system of "marginal trades" between SOs). In its exclusive form, it conflicts with various obligations under current and forthcoming EC directives to make cross-border capacity available to others and so is unlikely to be the only scheme in operation.[23] However, whatever scheme is finally adopted, there will need to be some "SMO Interchange" in the form of short-notice and real-time trades of energy and reserve

[23] For example, the forthcoming directive on cross-border trade (CBT). See Appendix C for a summary of the main terms of the CBT directive.

between the two system operators, using spare interconnector capacity, if an efficient dispatch is to be achieved.

4.3.3. Interconnector Trader

This scheme is perhaps the easiest to understand, since it represents a continuation of some elements of the current systems, but their application to the ROI's proposed LMP market is not straightforward.

The point of sale would be the southern end of the interconnector (we discuss below which physical nodes that means), where all trades (both exports and imports) would take place at the applicable LMP price. However, the timetable for the proposed ROI markets is not consistent with current arrangements for using the interconnector.

Currently, interconnector users must submit their nominated power flows two days in advance, but the proposed rules for the MAE provide no basis for interconnector users to schedule these nominated power flows into the ROI's market. They can submit an offer with a zero price, or else they may be able to use some of the technical parameters in the standing database to fix a certain level of offtake. Neither method necessarily guarantees that the Market Clearing Engine (MCE) will accept all the flows nominated over the interconnector.

Moreover, whenever the interconnector was congested (i.e. fully utilised), a nodal LMP price at the northern end that reflected conditions inside Northern Ireland would then set the price for exports from NI to ROI equal to zero. This is not a sustainable situation. That suggests that the MAE would need to set prices for exports at the southern node, or by reference to conditions inside the ROI, to avoid presenting interconnector traders with an unnecessary risk.

If the MCE does fail to accept a particular offer from an interconnector user to supply energy into the ROI in the dispatch at the start of a trading interval, several different outcomes are possible. Traders inside Northern Ireland (other than SONI) cannot respond to decisions of the MCE by arranging (or standing down) generation at short notice. Thus, the MCE's acceptance or rejection of offers from Northern Ireland will have no immediate impact on the efficiency of dispatch. Instead, it will merely affect the allocation of penalties for imbalances between interconnector nominations and the dispatch instructions within the ROI. The effect of these imbalances depends on how such penalties are allocated.

4.4. Balancing Rules for Interconnector Traders

If the MCE fails to accept offers from Interconnector Traders that match their nominations, but the SMO and SONI maintain power flows over the interconnector at the nominated level, they will create a surplus imbalance which would, under the normal rules of the MAE, incur some kind of penalty for the use of reserve. The rules would have to assign this penalty to someone, i.e.:

- interconnector users as a whole; or
- the interconnector user whose offer was not accepted, or
- a specially appointed "Interconnector Error Administrator" (a special account for accumulating and dividing out the costs of imbalances among the interconnector users or even among consumers).

The first of these options would remove most of the incentive for interconnector users to submit offers that avoid imbalances. The second option would make each interconnector user liable for its own failures to have its offers accepted – but such risks might be difficult to manage in practice and so offer few incentives for efficiency. The third option has the advantage that the interconnector users are exempt from imbalance penalties on the ROI side of the interconnector. Furthermore, if the Interconnector Error Administrator was linked to part of the interconnector capacity run by the "SMO Interchange" system by the SMO and SONI, it might be possible to avoid imbalances entirely by allowing the two system operators to arrange an adjustment to the net interconnector power flow in real time. However, this solution seems unnecessarily complex for a relatively simple problem.

There is a much simpler alternative that is closer to the reality of the scheduling process. It may first require an adaptation to the "metering code" to define the "actual" power flow coming from or delivered to an Interconnector Trader as equal to the power flow ***nominated*** by that Interconnector Trader. Then, the desired outcome can be achieved in either of two different ways:

1. Adapt the MCE so that the ***dispatched*** power flow equals the ***nominated*** power flow; or
2. Leave the MCE unaltered, but exempt Interconnector Traders from any penalties for real-time imbalances if the MCE produces a dispatch that differs from nominated (i.e., "actual") power flows.

Of these approaches, the former is the easiest to understand and therefore provides the most robust set of rules. The latter requires special treatment of Interconnector Traders, whereby all their "actual" injections and withdrawals are settled at the nodal price, without any penalty for failing to abide by the "dispatched" amounts. This rule can be justified, but may appear to be anomalous or even discriminatory.

The CER has proposed that penalties for imbalances should reflect the extent to which users cause them to be incurred. Interconnector users can legitimately claim that submitting a nomination two days in advance removes any uncertainty over their contribution to the market. Any subsequent variation in power flows over the interconnector would be the responsibility of the system operators (in the first instance, although they may trace back the source of their problems to failures by generators or consumers within their own markets and penalise them accordingly). Thus, by the CER's own standard, Interconnector Traders should bear no direct penalties for imbalances between their "dispatched" power flow and their "actual" power flow.

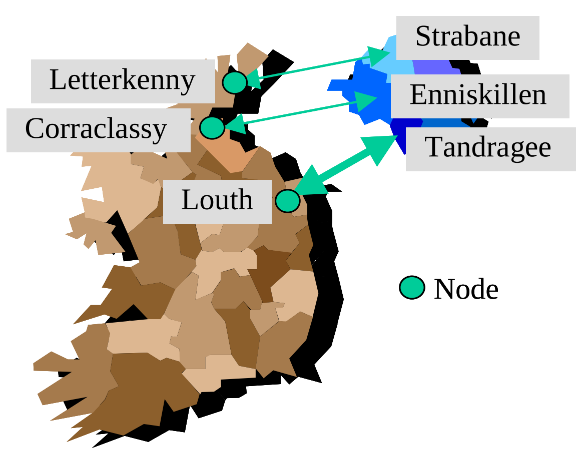
However, exempting Interconnector Traders from reserve charges would be a special rule intended to paper over a deficiency in the MCE, if it fails to recognise the pre-scheduling process on the interconnector. A far more transparent solution would simply accept interconnector nominations as a prior commitment to be accommodated within the market's pattern of dispatch. Many electricity markets offer a facility whereby an offer can be accepted as a fixed quantity and can earn the resulting market price, but does not set it; for instance, the old Electricity Pool of England and Wales allowed generators to submit "inflexibility flags" to achieve a certain pattern of output. Other traders (e.g. generators with must-run plant) would also appreciate the simplicity of such a rule.

4.5. Interconnector Points of Sale Within the ROI

At present, interaction between the two markets depends on "interconnection capacity" defined in terms of a net power flow between the two markets, rather than specific "line transfer capacity" on each of the three interconnectors individually. Since the two 110kV lines are in any case normally operated with a zero power flow, any actual exports or imports flows over the main 275kV line between Tandragee and Louth. However, neither system operator has ever specified its offers of capacity in such terms.

Under MAE, as shown in Figure 4.2, the three interconnectors will feed into three separate nodes on the ROI transmission network, for which the MCE will define three different nodal spot prices. In future, therefore, it will be necessary to be specific about who is selling how much power to which node, in order to arrange proper settlement. There are a limited number of practical solutions to this problem.

Figure 4.2
Interconnector Nodes Inside the ROI



4.5.1. Separate "line transfer capacities" to each node

SONI and the SMO could break down the "interconnection capacity" into three separate "line transfer capacities", one for each physical link, and separately allocate capacity on each link. Users of capacity would then receive the price specific to the node at the ROI end of each interconnector.

In practice, the line transfer capacity available to other users would be located only on the main 275kV interconnector entering Louth. The power flow on the 110kV lines to Letterkenny and Corraclassy is normally set to zero, except in emergency conditions, which implies that these lower voltage lines hold part of the "Transmission Reliability Margin", rather than any "Net Transfer Capacity". However, the system operators might have to defend this decision, if individual traders inside Northern Ireland began to see higher nodal prices at Letterkenny or Corraclassy than the prices available at Louth. In particular, the generator at Coolkeeragh is located in the northwestern part of Northern Ireland and might see better opportunities to sell its output at those nodes. Demands to be able to make such sales would require a revision to "line transfer capacities", which might undermine the security of the local transmission system – or cause the system operators to incur some costs to deal with new risks to security. SONI might also have to review its agreement with Coolkeeragh, whereby the generator agrees to support the local transmission system, if exports over the 110kV lines prevented Coolkeeragh from providing system support services.

4.5.2. Generic "interconnection capacity" to all three nodes

The alternative is to maintain the fiction of a single interface between Northern Ireland and the ROI, as at present, but even this rule offers two distinct possibilities for the point of sale and the associated nodal price.

On the one hand, trades over the interconnector could be settled at the ***average of the prices at the three nodes***, weighted by physical deliveries to or from each node. This is equivalent to giving each user of the interconnector an equal share in all three lines (bearing in mind that the share on each of the 110kV lines will normally be zero). This pricing scheme would work with the "Interconnector Trader" option, where the allocation of capacity is explicit, or with the "MAE Extension" option, in which the process of dispatch allocates capacity.

On the other hand, under the "MAE Extension" option, the MAE could determine the price for accepted offers from traders inside Northern Ireland in the same manner as the price for any other node. Under the MAE rules, the price paid for exports from Northern Ireland, for instance, would be ***the marginal cost of serving an incremental MWh of load at the interconnector's point of sale*** - i.e. the marginal cost of another MWh of south-north flow across the interface concerned. As at all other nodes, the MCE would find this price by identifying the "dual" for a dispatch that takes transmission constraints into account. Such prices reflect the offer prices of the marginal unit(s) on the system, marginal losses, and transmission congestion, including any congestion on the links to the interface.

Whenever accepted generation offers (or accepted demand bids) were sufficient to use the full interconnection capacity, the link would be congested. In such conditions, the locational marginal price for Northern Irish traders would simply be the point of intersection between interconnection capacity and their supply offers (or demand bids), meaning that the price would reflect production conditions inside Northern Ireland. For instance, if traders submitted offers with a zero price to ensure dispatch of committed nominations, the resulting price would be zero, but such a situation would not be sustainable. Any gains from trade would then arise within the general financial surplus accrued by the SMO from buying cheap and selling dear.

4.6. Superposition

The CER mentions that the new market might have implications for the continuation of super-positioning, i.e. the system whereby traders only have to ensure that the total ***net*** nominated flow over the interconnector is less than its total capacity. This procedure allows for traders to import and export at the same time, although the effects of the interconnector on the real system depend only on the net physical flow.

In practice, a system of super-positioning would only survive under the "Interconnector Trader" approach, in which there are physical transmission rights (PTRs) in place for North-South or South-North interconnector capacity. Under the "MAE extension", capacity is effectively allocated via the dispatch procedure, but the ROI market registers only accepted inputs to or withdrawals from the Northern Irish node, not actual flows over the interconnection. Superposition would arise if the MCE accepted (say) 250 MW of low-priced offers to supply power to the MAE and 50 MW of high-priced bids to buy power from the MAE. However, all such accepted offers and bids would be settled at the same nodal spot price, thereby removing any potential profits from arbitrage through superposition.

Of course, the "SMO Interchange" option removes all other traders from the capacity to which it applies and so prevents any form of superposition.

If PTRs and super-positioning remain in place under the new interconnector trading arrangements, the MCE would (ideally) have to accommodate nominations that exceed the capacity of the interconnector, but which are offset by nominations for flows in the opposite direction, such that the net flow matches the Net Transfer Capacity.

In such a system, it would be essential that all injections and withdrawals at each interconnector node were settled at the same price (or at least that the price paid for injections lies at or below the price charged for withdrawals). If the price for withdrawals (demand) can ever lie below the price paid for injections (generation), super-position would create limitless opportunities for arbitrage – buying at the demand price and selling at the generation price - which would inflate costs unnecessarily. This problem effectively rules out using the normal pricing rules, i.e. applying the weighted average demand price for imports into Northern Ireland, whilst using the nodal price for exports to the ROI.

4.7. Financial Transmission Rights

The CER's proposals seem to mean that NI generators/suppliers exporting to the ROI would receive an LMP at the border for their exports. The border nodes might develop as "market hubs" which traders use as the basis for contracts for differences (CFDs), but such an outcome seems unlikely, when all customers are paying the weighted average demand price. Suppliers or customer who signed CFDs at the border would be exposed to basis risk, i.e. the risk of variations in the difference between border prices and the demand price. As a result, Northern Irish exporters will be exposed to the risk of variation in border prices if they sign no contracts, or to basis risk if they sign contracts with customers that refer to the demand price.

To achieve a price hedge, Northern Irish exporters would need access to Financial Transmission Rights (FTRs) that protected them against variation in the difference between the border price and the demand price. They would then be able to sign CFDs with customers inside the ROI without being exposed to basis risk. (See Section A.7 in Appendix A for an explanation of basis risk and the role of FTRs.).

However, such FTRs might be a mixed blessing. To the extent that the border price lies ***above*** the demand price, FTRs linking the two prices would reduce both the variability and the ***level*** of revenues received by Northern Irish exporters. On balance, such exporters may prefer to accept the variability of the border price, in the knowledge that expected prices are higher. Only detailed modelling of prices and the associated risks will indicate whether exporters would be wise to export without such hedges. In the meantime, representatives of Northern Irish consumers would not wish to demand that the CER imposes FTRs on interconnector capacity, in case they depress the revenue to be earned from exports and hence, the benefits to customers inside Northern Ireland. However, they would want traders to be able to acquire FTRs when it was beneficial to do so.

In time, market hubs (offering a liquid market in CFDs) might emerge at other locations within the ROI, in which case interconnector traders might want FTRs to manage basis risk between the interconnector nodes and these market hubs. The creation of such markets is however unlikely, given the dominance of ESB and vesting contracts that reduce ESB's risks.

4.8. SO to SO Trading on North-South Interconnector

Any new arrangements that are put in place for North-South interconnector trading need to ensure that the SOs can still engage in efficient real-time trading. The CER hopes to promote more efficient dispatch by moving the ROI to a transparent half-hourly spot market price. However, the dispatch will only be efficient if traders can respond to the resulting instructions and the SMO will only publish nodal spot prices once the dispatch has been decided, an hour in advance. This aspect will not facilitate trade between the two system operators.

4.8.1. "Marginal trading" in advance

At present, SONI and ESB can agree to trade power during the period after NI gate closure and before ROI gate closure. This facility, known as "marginal trading", allows SONI to schedule additional capacity in Northern Ireland, or to ask ESB to schedule additional capacity in the ROI, if such actions would reduce generation costs or would reduce the risk of an outage. In general, it is not possible to schedule additional capacity at short notice. However, the CER has not offered any alternative means for SONI to schedule additional generation in advance under the proposed MAE. The CER's proposed market leaves plant scheduling to individual traders and only arranges a short-term dispatch.

To secure the all-island transmission system and to arrange an all-island efficient dispatch, SONI would need to be able to agree additional output in advance from generators in the ROI or NI markets. Such agreements would need to relate to particular generator capacity, rather than to the wholesale market in general, in order to ensure that the dispatch was secure. However, under the proposed MAE, SONI would not be able to secure such purchases or sales without facing a risk that the generator's offer into the MAE would be rejected. When that happens, persisting with the pre-scheduled pattern of output (whilst all other generators followed the instructions issued through the MAE) might cause the transmission system to be insecure, the opposite of SONI's intention.

4.8.2. Real-time trading

Under the CER's proposals, real-time trading between SOs would be settled as the use of reserve, which means that operation of the ROI's integrated reserves markets will also need to accommodate North-South trade in real time. However, assuming that SONI (and/or the SMO) entered such a market with the reserve that they offer each other, the outcome of such a market might be inconsistent with the reserve sharing agreement between the system operators.

4.8.3. Alternative solutions

To avoid such inconsistencies, the SOs could trade energy and reserve outside the MAE, using both spare Net Transfer Capacity (made available on a use-it-or-lose-it basis) and the Transmission Reliability Margin (through use of "reserves"). At its simplest, the SMO would act as the agent for these trades in the MAE, receiving any revenues and incurring any penalties, whilst arranging the trades with SONI "upstream" of the ROI market, as at present. This arrangement would keep SONI insulated from short-term market risks in the ROI, as at present, and so would not require a change in SONI's regulatory arrangements.

Some of the existing arrangements may need to be revised to accommodate the proposed new market arrangements in the ROI. For example, at present SONI and ESB NG sometimes swap power in the northwest of the island over the two small interconnectors, in order to support a weakness in ESB NG's system in the area. If, under the new arrangements, the MAE were to pay and charge SONI for this exchange of power at two different LMPs, then either the SMO could pay SONI a contract price for this (reserve) service and receive any net revenue from the MAE, or else SONI could receive the net revenue as compensation for any costs that result. In practice, since the decision to use this reserve service lies with the SMO, it would be more efficient for SONI to charge the SMO the costs of the service and for the SMO to receive the price difference as the short-term net benefit.

4.9. Trading of Reserves

The two system operators currently provide some reserve to each other through a reserve trading agreement. This agreement provides a mutual benefit and does not entail any financial recompense. Under the new market rules, reserve generators will be paid for providing reserve. However, in practice, SONI's provision of reserve is unlikely to be included in this market, since it would allow SONI to receive a revenue for a service currently provided free of charge. If SONI demanded payment, the SMO would probably demand compensation for the reserve that the ROI provides to Northern Ireland, and there is no guarantee that Northern Ireland would gain as a result. On balance, therefore, it seems that the best option would be a set of market rules that recognised the provision of reserve by Northern Ireland as a matter of mutual cooperation. NGC and the Scottish electricity companies operated on this basis for many years under the Pool, simply by leaving some of the England-Scotland interconnector capacity available as reserve and deducting this amount from NGC's requirement for "operating reserve".

4.10. Moyle

There is no reason to reform the existing arrangements for capacity allocation and trade on the Moyle interconnector while NI remains separate from the ROI LMP market. The introduction of BETTA in GB, combined with the expected increase in interconnector capacity between Scotland and England, is likely to result in more effective competition in Scotland and downwards pressure on the prices at which power is offered for export into NI. However, we do not anticipate any major effects. The biggest problem for users of the Moyle interconnector will be trying to anticipate the most efficient use of their capacity, given the need to schedule flows in advance and the uncertainty over the ultimate price of power in the ROI. Delaying gate closure on the Moyle interconnector might reduce some of these risks to traders, but could not eliminate them entirely.

4.11. Conclusion

Interconnector trading raises a number of complex concerns, most of which would be alleviated by minor amendments to the market rules in the ROI. The main points arising from this analysis of interconnector trading are as follows:

- The CER's proposal to extend the MAE onto the interconnector, so that traders in Northern Ireland can offer power directly, is not consistent with current timetables for trading inside Northern Ireland and may produce a lower price for exports when the interconnector is fully utilised (depending on the price rules).

- The combination of "Interconnector Trader" (physical transmission rights) and "SMO Interchange" (trades arranged between the system operators) is closer to current arrangements and requires the least amendment to interconnector access systems. Under this proposal, interconnector users would buy and sell power at the southern end of the interconnector at a price determined by conditions within the ROI.

- Even under the "Interconnector Trader" option, traders will face a risk of imbalances if they have to nominate cross-border flows in advance, but can only offer power to the MAE an hour in advance, and cannot guarantee it will be accepted. The CER could however amend the rules to give interconnector nominations "must-run" (i.e. inflexible) status, so that the Market Clearing Engine was bound to accept nominated power flows over the interconnector. This would not interfere with an efficient dispatch provided that the MAE does not impede system-to-system trading in real-time (i.e. the MAE should allow some "SMO interchange").

- Under the "Interconnector Trader" option, SONI will have to be more specific about the point of sale for exports within the ROI. The solution closest to current working arrangements is to offer all interconnector users a flow-weighted average of generation prices at all three nodes (in the knowledge that flows over the two 110kV lines are normally zero, so that the price at the Louth node will predominate).

- The super-position rules would only apply under the "Interconnector Trader" option.

- Interconnector traders would be exposed to basis risk if they sold/bought power at the LMP prices for interconnector nodes, but signed contracts with customers that refer to the weighted average price at the notional demand node. FTRs would remove the basis risk, but might reduce overall revenues from exports.

- The Irish electricity system will still benefit from reserve sharing agreements between SONI and the system operator of the ROI (the SMO). SONI will want to deal directly with the SMO and let the SMO act as the interface with the ROI market.

These conclusions imply that Northern Ireland would want the design of the MAE to accommodate particular features of cross-border trade. None of these demands are unreasonable and they can be accommodated relatively simply.

5. IMPLICATIONS FOR NI

5.1. Prices and Production in NI

While NI remains separate from the ROI market, the impacts of the new ROI market arrangements on NI will be felt through interconnector trading.

- Value of exports

Some of the proposed measures are likely to depress spot market prices in the ROI market, in particular the generation adequacy measures and possibly also the vesting contracts, although overall their effects are uncertain.

If spot market prices are depressed in the ROI following the introduction of the MAE, in particular at the North-South interconnector node, this will have a negative impact on the extent of trade from NI to ROI, which would in turn raise the prices charged to franchise customers in NI, since NIE PPB would face a loss of export revenue.

- NI traders need access to FTRs

NI traders trading with the ROI will be exposed to price volatility through volatility in LMPs at the border. NI traders need to be able to acquire financial transmission rights (FTRs) on reasonable terms, to hedge variations in the gap between prices at different nodes and to allow them to manage this volatility. NI traders may prefer not to use FTRs if border LMPs are expected to average out above the uniform demand price in the ROI, but this is a choice that can and should be left to NI traders.

NI traders will probably need to lobby hard to persuade the CER and the SMO of the need to issue FTRs since ESB is unlikely to do so. ESB's vertical integration and dominance give it a natural hedge against basis risk in an ROI LMP market, which means it has little incentive to lobby for FTRs. In New Zealand, where many incumbents are vertically integrated on a regional basis, FTRs still have not been made available to the market in spite of Government urging. A lack of FTRs in the ROI would have an adverse impact on smaller non-vertically integrated players, and deter market entry, further entrenching the dominant position of ESB. It would also mean that the effective physical transmission rights held by existing players, including NI traders, could not be protected by "grand-fathering" them as FTRs.

The CER needs to define carefully the conditions applying to FTRs for use by traders buying or selling across the North-South interconnector. The CER needs to decide whether to allocate an FTR to the interconnector itself, in which case users would automatically be allocated a share of this FTR whenever they reserve capacity or arrange a trade on the interconnector, or to allocate FTRs directly to interconnector users.

- System-to-system trading

Since system-to-system trading between the SOs is a crucial means of ensuring efficient dispatch in real-time, both in NI and ROI, it is of paramount importance that the MAE does not obstruct this form of trade.

Further, since there are potential efficiency gains from system-to-system trading of reserves the MAE should promote such trading.

- Changes to NI market rules

The introduction of MAE in the ROI will create severe problems for interconnector users, unless there are changes to the interconnector trading arrangements, and possibly also to NI market rules. It may be beneficial to change the following aspects of the NI market rules:

- gate closure, which may need to be moved closer to real-time;
- scheduling and dispatch, which may need to reflect a dispatch determined by the MAE over the North-South interconnector; and
- settlement, which may need to accommodate settlement of imbalances at the interconnector node at an LMP price determined by the MAE (to the extent that settlement within the ROI affects the flow of payments within NI).

However, the new electricity market in the ROI could accommodate the current arrangements for nominating interconnector trades with a minimum of change for NI, if the CER was prepared to adapt the Market Clearing Engine slightly in recognition of the existing rules.

5.2. Existing Contracts

If ESBI Coolkeeragh gets access to high LMP prices in the NW of the ROI via the 110kV cross-border transmission lines, then SONI may want to revisit its ″system value agreement″ with ESBI Coolkeeragh, to ensure that it still represents value for money for NI customers. Currently, it assumes that SONI is the only party able to capture the value of supporting the ROI transmission system.

5.3. Renewables

The introduction of a mandatory gross pool in the ROI would offer some advantages to large wind generators in the ROI since it guarantees them a market for their output. However, if the costs of reserves in the ROI market are charged to market participants in the ROI who cause the SO to incur these costs, then the output of wind generators is inherently unpredictable and will incur higher costs of reserve than if these costs had been spread evenly across the whole market.

This allocation of costs will adversely effect the competitive position of wind generators within the ROI, resulting in less wind generation being commissioned ***or*** a need for higher government subsidies. Imposing more costs on wind generators in the ROI may increase the attractiveness of investment inside NI, but the effect would be negated by the payment of higher subsidies.

These costs and benefits would only impact on NI wind generators were NI to integrate with the ROI market.

5.4. Conclusion

Being situated at one extremity of the ROI transmission system, NI's electricity system has a number of specific problems with the CER's proposals. Many of these problems might not be apparent from examining the ROI market as a whole, but some raise issues of general concern.

The problems we have identified all need to be addressed by the CER in order to ensure that the introduction of the MAE does not impede all-island trading, or the further integration of the NI and ROI markets to form a single all-island market. These problems are not insurmountable, but their resolution will require close co-operation between interested parties in NI and ROI to ensure that all factors are taken into account and that the CER's proposals do not diminish the efficiency of all-island electricity trading.

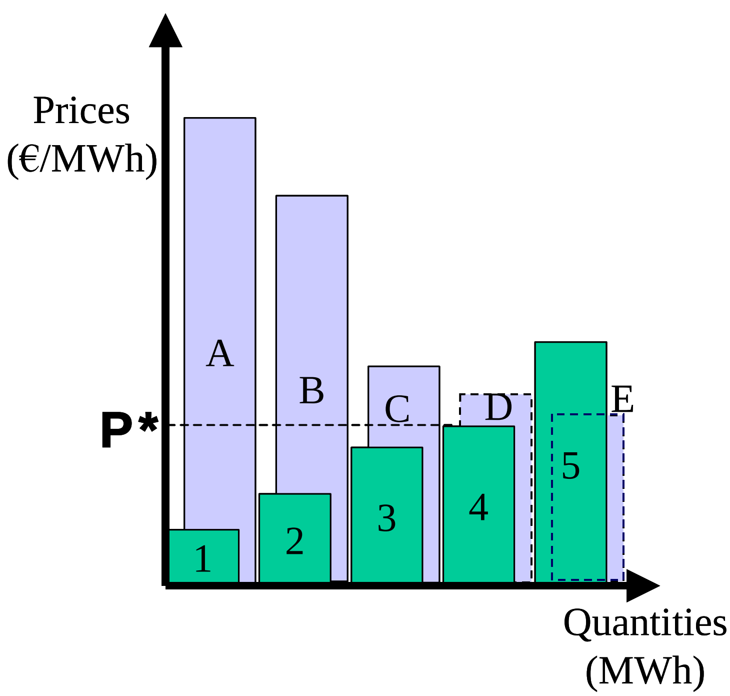
APPENDIX A. HOW LMP MARKETS WORK

The operation of electricity markets has been studied for many years and the principles are well understood. Figure A.1 shows how the basic rules work in a single price market, i.e. a market in which all power is traded at the same price in any one "settlement period". (A "settlement period" is the period for which each price is calculated and is either an hour or a half-hour. The standard in the UK and the ROI is a half-hour.)

A.1. Matching Offers to Bids

In Figure A.1, generators submit five "offers", reflecting the generation capacity that they have available. In this case (for simplicity), each offer covers the same amount of potential output, but has different prices. In the figure, the offers (the darker blocks) have been placed in order of rising price from offer 1 to offer 5. The market process matches these offers against demand – either against a fixed quantity or against a set of "demand bids", such as bids A to E (the lighter blocks) shown in the figure. The aim is to ensure that output is matched to demand, as long as the valuation of customer needs (price in a demand bid) exceeds the cost of meeting that need (price in the corresponding generation offer). In the case shown below, demand bids A, B, C and D can be matched to generator offers 1, 2, 3 and 4, but demand bid E has a price below generator offer 5, and so is excluded from the matching process.

Figure A.1
Typical Single Price Electricity Market



In contract and spot markets arranged by traders, the process of matching supply and demand takes place in advance of delivery; actual outputs and demands may differ from the purchases and sales registered by the market matching process. However, in any electricity system, generation must match load minute by minute, in order to maintain the frequency and to prevent catastrophic outages. The process of matching supply and demand takes place in real time through the process of "central dispatch", whereby a system operator instructs generators to produce output (or to adjust output relative to prior commitments) to maintain a balance with demand. The system operator (or a separate market operator) then examines the resulting pattern of actual outputs and derives a market price from it.

A.2. Setting a "Marginal Price"

In this case, the market applies a conventional rule for identifying a "market clearing price", by setting the price P* equal to the offer price of the most expensive generator actually dispatched by the system operator (i.e. the generator that submitted offer 4). This pricing rule is sometimes called "marginal pricing", because it sets the price equal to the cost of the "marginal" plant, i.e. the most expensive plant required to meet demand. Lest this description of the rule seems perverse, it should be noted that the resulting price is the ***lowest possible*** single price consistent with a least-cost dispatch. If the price were any lower, at least one offer would be loss-making and generators would not wish to generate enough to meet demand. Hence, this price encourages a least-cost pattern of generation and minimises costs to customers in the long-run.[24]

A.3. Adding the Locational Aspect

The principle of setting a different price for electricity at each node on a transmission network seems a simple one – akin to the way in which prices for other commodities differ by location due to transport costs. For instance, if it costs £25 to produce a tonne of coal at A, and £5/tonne to transport it from A to B, one would expect the price of coal at B to be £30/tonne, i.e. to be in principle the sum of production costs and transport costs. However, transmission of electricity is more complex than the transport of commodities like coal. Many of the risks and other problems arising from LMP systems derive from the special way in which the principle is applied to electricity markets. The following section therefore describes the process of calculating LMP prices in simple terms.

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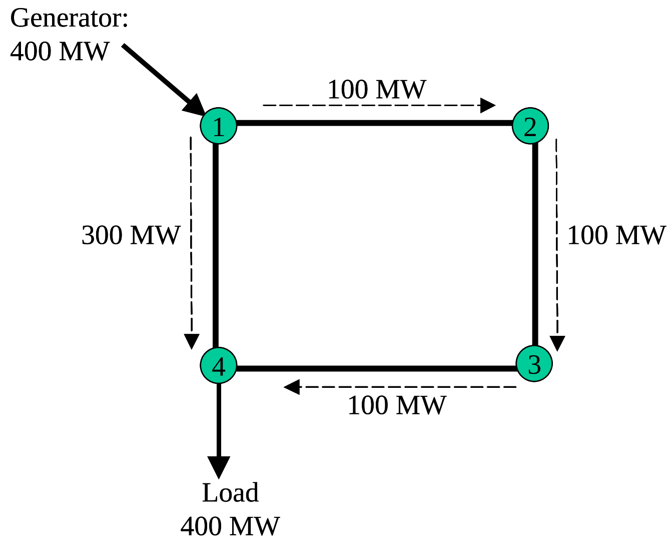
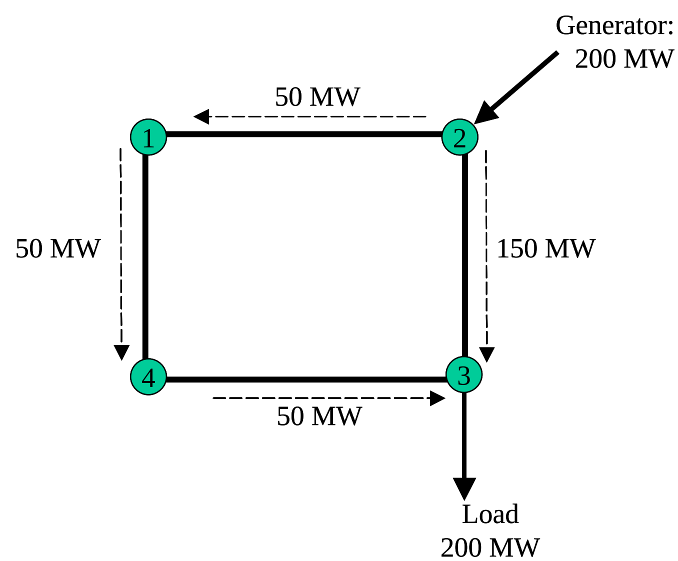
24 In recent years, reforms in Great Britain have prompted some discussion of the choice between a single (or "market-clearing") price system and a "pay-as-bid" system that sets the price for each offer equal to the price quoted in the offer. Some naïve commentators have suggested that the latter system might produce lower prices to consumers, because offer prices are below the market-clearing price. However, if generators know that they will receive their offer price rather than the market-clearing price, they will make sure to quote their estimate of the market-clearing price when they submit their offers. Hence, in practice, the "pay-as-bid" system does not produce lower prices, although the results may depart from a least-cost dispatch if generators fail to estimate the market clearing price accurately and submit offers that mislead the system operator into dispatching generators in the wrong order.

Figure A.2
The Effect of Kirchoff's Laws

Example 1:



Example 2:



Box 2: Kirchoff's Laws on Power Flow

In these figures, each link (1-2, 2-3, 3-4 and 4-1) is the same length in electrical terms and so has the same resistance. Example 1 shows how generation of 400 MW at node 1 would travel around the network to load at node 4. The direct route (1-4) has only ***one third*** the length (i.e. resistance) of the indirect route (1-2-3-4), so Kirchoff's laws dictate that three times as much power (300 MW) flows over the direct route as over the indirect route (100 MW). Example 2 shows how generation of 200 MW at node 2 serving load at node 3 would be split, with 150 MW taking the direct route (1-3) and one third - 50 MW - taking the indirect route which is three times as long (2-1-4-3).

A.3.1. The laws dictating power flows

In an electricity system, several factors complicate the calculation of prices that reflect the (marginal) cost of producing and transporting electricity to each node on the network - in particular, the way in which load flows around a transmission network. Below we explain the laws dictating power flows and how they affect the calculation of nodal prices.

Although it is instructive to think about transport costs as a source of price differences in other commodities, electrical engineers know that electricity does not flow directly from A to B in the same way as other commodities being transported by road, rail, sea or air. Generators and loads (i.e. customers) are linked together by a large and complex network of transmission lines. Electricity flows from generators to loads over these lines according to predictable laws, known as "Kirchoff's laws", which reflect the physical characteristics of the transmission network. These laws describe the effect of electrical flows following the line(s) of ***least resistance*** from A to B. For technical reasons, any flow of electricity tends not to travel down one line from A to B, but to divide up among all the routes from A to B ***in inverse proportion to their resistance***. The result is that some power flowing from A to B (albeit sometimes only a small proportion of the total) will travel over every part of an integrated network. These laws underpin the calculation of "locational marginal prices" in nodal electricity markets.

Figure A.2 shows how Kirchoff's laws work for a simple four-node network.[25]

During the 1980s, a group of US academics[26] realised that Kirchoff's laws could be used to mimic a transport model for electricity, enabling them to work out how prices at B might depend on costs of production at A – or rather, how prices at B might depend on production costs at A, C, or D, or any combination of these nodes, as we discuss below.

A.3.2. Locational Marginal Prices (LMP)

Figure A.3 shows how the pattern of power flows (actually, the sum of the power flows shown in Figure A.2) determines nodal electricity prices. Load of 200 MW at node 3 and 400 MW at node 4 must be served by generation located at nodes 1 and 2. The system operator instructs generators to produce output according to the least-cost pattern ("least-cost dispatch"). The generator at node 1 has the lowest cost of production, £15/MWh, but it cannot produce enough to meet all 600 MW of load, because there is a limit of 50 MW on flows across the line from 1 to 2. If the generator tried to produce 600 MW, its output would

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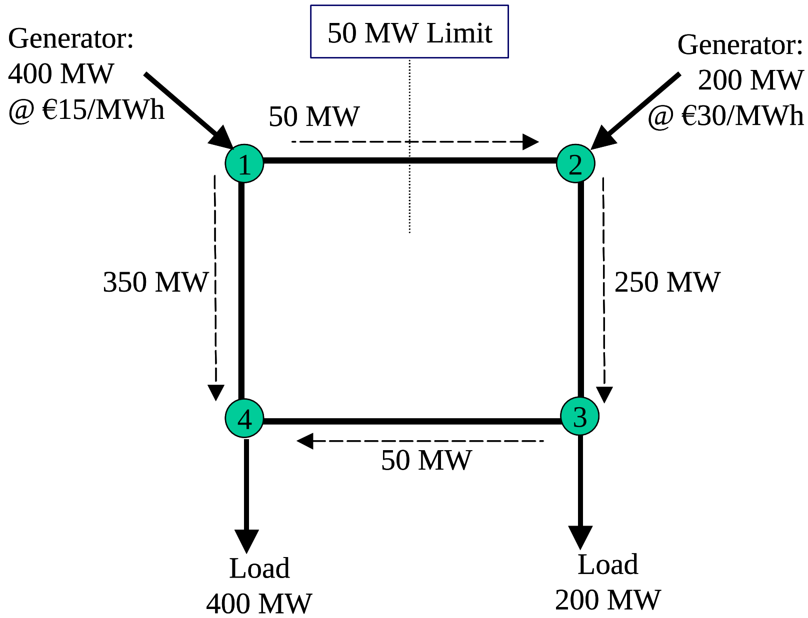
25 As electricity travels through transmission lines, it encounters resistance and some energy is lost in the form of heat; for simplicity, we ignore such transmission losses in this example and assume that the amount sent out by generators is equal to the amount received by consumers. In practice, of course, generation must exceed load, in order to cover transmission losses.

26 The definitive guide was set out in Schweppe FC, Caramanis MC, Tabors RD and Bohn RE (1988), ***Spot Pricing of Electricity,*** Kluwer Academic Publishers, but this book summarises work by the same team dating back to the early 1980s.

split, with 400 MW going direct from node 1 to node 4, and 200 MW taking the route 1-2-3. The flow of 200 MW over line 1-2 would overload it. Instead, the system operator must balance output from the generator at node 1, by taking output from the generator at node 2, even though that output cost more, i.e. £30/MWh. The balance of output from nodes 1 and 2 sets the price at node 3.

Figure A.3
Constrained Dispatch and Prices



In economic terms, the ***marginal*** price of load at a node is equal to the cost of meeting a small ***change*** in load. If load at node 3 rose by 1 MW for one hour, the system operator would have to call forth one more MWh of output. To avoid overloading line 1-2, the system operator would instruct the generator at node 1 to produce an additional 1/3 MWh, and the generator at node 2 to produce an additional 2/3 MWh.[27]

[27] From node 1, a half of the additional 1/3 MWh (i.e. 1/6th of a MWh) flows clockwise over line 1-2. From node 2, a quarter of the additional 2/3 MWh (i.e. 1/6th of a MWh) flows anti-clockwise over line 1-2. These flows balance and leave the net flow unchanged at 50 MW, i.e. within the limit. Node 3 therefore receives clockwise flows of 1/6th MWh from node 1 and ½ MWh from node 2, and anti-clockwise flows of 1/6th MWh from node 1 and 1/6th MWh from node 2. The sum of these flows is 1 MWh.

Table A.1
Marginal Cost of 1 MWh Load at Node 3

Location	Volume (MWh)	Unit Cost (€/MWh)	Total Cost (€)
Node 1	0.333	15.00	5.00
Node 2	0.667	30.00	20.00
			25.00

Table A.1 shows the marginal increase in generation costs caused by this change in load, ***assuming that the additional output is available at the same price as the outputs in Figure A.3.*** The resulting increase in total generation costs would be £25, which implies that the marginal cost of serving load – the "locational marginal price" - for node 3 would be £25/MWh.

An increase in load of 1 MWh at node 4 would have a different cost. This time, the balanced set of additions to generation would be reversed: 2/3 MWh from node 1 and 1/3 MWh from node 2. The increase in costs would be £20, implying a price at node 4 of £20/MWh.

Of course, any additional load at node 1 could be served entirely be the generator at that node without changing network flows, so the locational marginal price at node 1 is £15/MWh, the unit cost of generation at the node itself. On the other hand, any additional load at node 2 would have to be served by increasing output at the generator at node 2, in order to avoid reducing its net injection into the network and unbalancing power flows. Hence, the locational marginal price at node 2 is £30/MWh, the unit cost of generation at that node.

A.3.3. Settlement procedures

Table A.2 shows how the market would settle claims arising from this pricing procedure. Each generator and load is assigned to a particular node and output/consumption is awarded the price that applies at that node. The market then pays for generation and charges for load at each nodal price.

Table A.2
Settlement of Generation and Load at Nodal Prices

Account	Location (node)	Price (€/MWh)	Output(+)/Load(-) (MWh)	Receipts(+)/Charges(-) (€)
Generator A	1	15.00	400	6000
Generator B	2	30.00	200	6000
Load X	3	25.00	-200	-5000
Load Y	4	20.00	-400	-8000
Total for Period				-1000

As Table A.2 shows, a nodal spot market will normally pay out to generators less than it charges to load. This result is intuitive, since one would expect power to flow from (i.e. be generated in) lower price areas to higher price areas (i.e. areas of load where generation is in short supply).

A.4. Price-Setting Algorithms

In practice, LMP-style electricity markets don't work through such laborious calculations for each node as those set out above. Instead, they derive each node's price from a computer program that shows the additional cost of load as the output of an optimisation routine. (See Box 3.)

Box 3: Solving for the Marginal Cost of Production at Each Node

The task of minimising the additional cost of meeting additional load can be formulated as an optimisation programme. The programme specifies an overall objective (minimising the total cost of generation), a set of transmission constraints on power flows (Kirchoff's laws) and set of 'load constraints' for each node (at each node, generation plus net power flows arriving over the network must at least equal load at that node). Such programmes routinely report the cost of tightening constraints within the programme, e.g. the cost of increasing the load that has to be met at each node. These costs are known as the "duals" or "shift factors" of each constraint. The duals on each load constraint represent the marginal cost of ***increasing load*** at each node, which is the "Locational Marginal Price".

This price-setting procedure has some important characteristics:

1. The calculation of prices takes the following items as data inputs:

   - metered generation (or the system operator's dispatch instruction to the generator) at each node;
   - metered load at each node;
   - the electrical characteristics of the network links between nodes;
   - the cost of ***increasing*** generation at each node (which may differ from the cost of the metered level of generation);
   - the price of shedding load considered to be "dispatchable".

2. Locational prices within any network may differ between nodes by up to about 10% due to the transmission costs associated with physical losses (not included in the examples given above);

3. Prices will differ between nodes by relatively large amounts when power flows are constrained by limits on certain lines, which cause relatively expensive generation to be dispatched "out of merit" (i.e. even though cheaper generation is available elsewhere);

4. The price at a particular node may reflect (a weighted average of) production costs at a small number of nodes, whose output must be balanced to avoid overloading some parts of the network;

5. The price at a particular node may reflect production costs at quite distant nodes.

Point 1 in this list means that the adoption of LMP does not in itself improve the efficiency of dispatch, compared with a single price model. Both LMP and single price models rely on a system operator to decide the pattern of dispatch and to derive prices from it, on the assumption that the pattern of output is efficient. Point 1 also means that LMP calculations ignore the offer prices of generating capacity that has been dispatched and focus only on the "marginal" cost associated with an ***increase*** in generation at a node.

Points 2 and 3 indicate the need for data on network characteristics, in particular the line characteristics such as resistances that affect physical losses, and the thermal limits (literally, the limits on the extent to which transmission lines can be allowed to heat up) and other factors that determine the location and extent of any transmission constraints.

Points 4 and 5 mean that it may be difficult to understand (and hence to predict) how the price at any one node is determined. If traders do not understand the nature of the network, for instance, it will be hard for them to work out why in our example above the price at node 3 is a particular weighted average of offer prices at nodes 1 and 2, especially if these nodes are a long way away in a more complex network.

These points have important implications for the transparency of the LMP market process and the risks to which traders are exposed as a result.

A.5. The Choice of Nodes

When setting up a LMP system, the designers have to choose the nodes for which the system will calculate prices.

A.5.1. Transmission and distribution networks

Normally, LMP systems cover transmission networks, but do not cover any interconnected lower voltage networks. The omission of distribution networks is often a pragmatic matter - the distribution companies may refuse to take part in the scheme. However, it may also reflect the observation that distribution networks have a simple "radial" structure, meaning the distribution lines "fan out" from their connection to the transmission network, with no internal constraints. In such cases, electricity prices at different locations within the distribution network depend only on the LMP at the point of connection to the transmission network and physical losses within the distribution network (which are difficult to measure accurately, but relatively easy to estimate). However, not all distribution networks are simple, radial systems, which may raise questions about the appropriate boundary of LMP pricing.

A.5.2. Connection nodes and switching nodes

For simplicity, most LMP systems only calculate prices for nodes at which power enters or leaves the transmission network ("connection nodes"), but not for nodes where several transmission lines meet ("switching nodes"). Prices at switching nodes are not needed for settlement purposes – although anyone thinking of connecting a new generator or load to a switching node might be interested in knowing what prices apply to it now. It may be beneficial to announce prices for a switching node, if it represents the most obvious point of connection for future generating capacity.

A.5.3. Nodes versus zones

The remaining question, often discussed during the design of LMP markets, is whether generators and customers should sell and buy electricity at the price applicable to the node to which they are connected, or whether the system should apply the same average nodal price for multiple nodes within a pricing "zone". Box 4 sets out the main arguments that have arisen in this context.

Box 4: Pros and Cons of Nodes and Zones

1. In the past, calculating, say, three or four "zonal" prices required less computing power than, say, 100 "nodal" prices. However, computing power has now become so cheap that this consideration is a very minor one.

2. Dividing the market into zones and solving for the price in each zone, using the method set out in Figure A.1, seems more transparent to many traders than using the kind of complex nodal pricing algorithm described in Box . However, unlike a computer, traders may fail to identify interactions between distant nodes i.e. pricing effects from outside the zone, so zonal prices fail to settle at the right levels.

3. Computing average prices for a zone hides information about the local value of electricity at different nodes within the zone. As a result, it reduces the efficiency of the response by generators and consumers. This loss of efficiency is significant, if nodal prices differ widely and unpredictably within a zone.

4. Some commentators claim that forming zonal markets concentrates liquidity around one market price and favours the creation of transparent contract markets. However, the associated loss of efficiency (i.e. "false trades" in a fictitious product at a price that does not represent the value of electricity at any real location) may outweigh any of the tenuous potential benefits attributable to increased liquidity.

5. It may be impossible to divide a complex network into zones in which prices do not differ widely and unpredictably and, in any case, the boundaries of such zones are likely to be arbitrary and open to continual pressure for amendment.

The balance between these arguments has varied over time, as conditions change, but at present they probably lean in favour of using nodal, rather than zonal, prices in a centralised market of this type. Point 2 remains a relatively strong argument against the use of LMP pricing algorithms at all. The well-known example of the Nordic electricity market, sets different prices for Denmark, Finland, Sweden and for up to five zones inside Norway, but it does not employ the complex type of pricing algorithm set out in Box 3. Instead, it sets a "single price" for each zone using the simple matching method shown in Figure A.1. The simple matching method may well be more transparent than LMP algorithms, but it does not provide a technical or economic argument for combining LMP nodal prices into zonal prices. Indeed, as Point 5 states, the process of combining nodes into zones within a meshed network may require so many arbitrary decisions as to undermine any claims to greater transparency.[28]

Nevertheless, electricity market designers face pressure to insulate generators or – more likely – consumers from the fluctuations in nodal prices, because of concerns over market power and risk hedging, which we discuss separately below.

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[28] Stoft S. (1997), Zonal Pricing – Balm or Puzzle? Electricity Journal, Volume 10 No. [1], January/February 1997.

A.6. Market Power

Some comments on energy markets suggest that putting more producers and consumers into one "zonal" market helps to reduce market power, compared with a multitude of nodal markets. This argument is fallacious, although the effects of market power differ between nodal and zonal markets.

If a generator firm has market power in the market as a whole, because it owns a large share of total generating capacity, it can raise market prices in general, whether the market sets single, nodal or zonal prices.

If the system operator requires a particular generator to run, because of a transmission constraint as in Figure A.3, that generator possesses "local market power" and can raise its offer price. In a nodal market, that may raise the price at the generator's node and hence what the generator gets paid. It may also raise the price for customers at that node (depending on the pricing rule), and the price for generators and customers at other nodes (depending on the physical characteristics of the network).

In a zonal market, the generator will still be able to raise its offer prices. That will normally raise the price paid to the generator, and special market rules may set this price outside the general matching procedure which sets the zonal market price. However, the increase in the generator's offer price may feed through into an increase in the zonal market price. Indeed, it is possible to construct examples (admittedly, special cases) where a generator with local market power can raise market prices in a zonal market, but not in a nodal market.[29]

Hence, the existence of market power is an expression of physical network characteristics, but its impact on market prices depends on the specific conditions and pricing rules. A generator with market power can (by definition) raise the price it receives, but it may also raise prices for other generators and customers in nodal or zonal spot markets.

The incentive for generators to use market power to raise prices depends on the extent to which they benefit from doing so. If they raise the offer prices of price-setting generators, they may raise the spot price, but they may also lose market share to other companies. Generators will accept this loss of (low margin) market share, if the result is higher prices for the output of other ("inframarginal" or "baseload") generators that continue to generate. However, if generators have sold a large share of this output in long-term contracts at fixed prices, they will not benefit from the rise in spot prices. Hence, the creation of long-term

[29] Harvey SM and Hogan WW (2000), Nodal Congestion Management and the Exercise of Market Power, 10 January 2000. The example in this paper concerns a mid-merit generator that would not run in reality, due to a transmission constraint, but which sets the price in a zonal ("unconstrained") market. Such a plant may have market power in a zonal market (if the next most expensive generator has much higher costs), but no market power in a nodal market (since it wouldn't run).

contracts mitigates the effect of market power, by reducing or removing the incentive to exploit it.

A.7. Risk Hedging

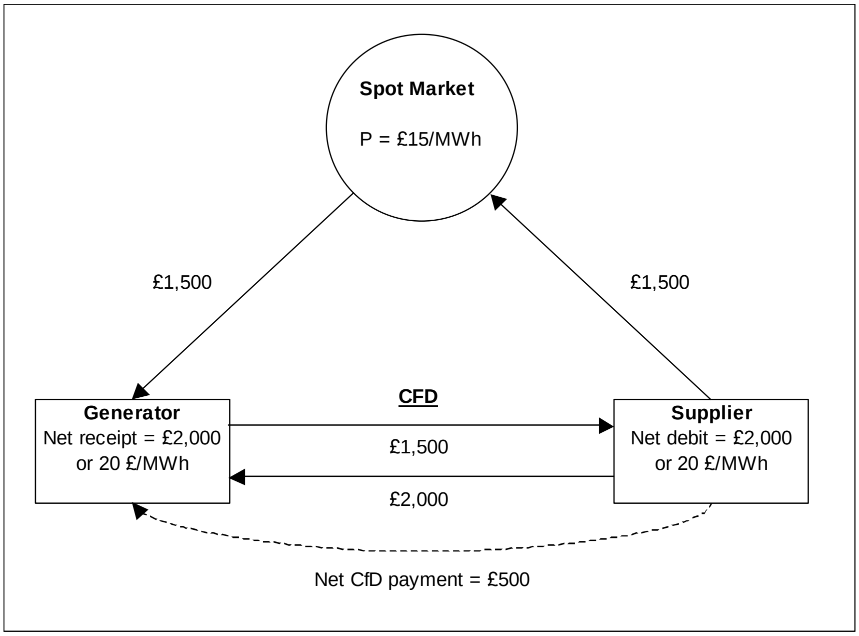
LMP systems usually operate as a "compulsory centralised market", meaning that all generators (above a certain size) must direct all their physical output through the market and be paid the LMP, whilst all suppliers must buy all the electricity they sell to consumers (barring a few exceptions such as purchases from small generators) from the same market at the LMP. This description of the arrangements seems to leave no room for bilateral contracts, but in fact such systems have always fostered the creation of ***financial*** contracts that perform precisely the same function.

A.7.1. Contracts for Differences (CFDs)

The operation of financial energy contracts is well understood within Europe and the US. Suppose that a generator sells 100 MWh to a supplier through a "compulsory" spot market. Both the generator and the supplier are exposed to the spot market price which, for the sake of example, might vary between £15 and £30 per MWh. The generator would receive (and the supplier would pay) either £1,500 or £3,000 for these 100 MWh.

Suppose that, in advance, the generator and the supplier would like to fix the price for these 100 MWh at £20/MWh, by signing a financial contract. Under this contract, the generator must settle the contract by paying the supplier the spot market value of the energy, i.e. either £1,500 or £3,000, in lieu of delivering 100 MWh of energy. (At this point, the generator has no revenue, since it has handed over a rebate equal to its earnings from the spot market, and the supplier with no net cost, since this rebate from the generator exactly covers the cost of buying 100 MWh from the spot market.) In addition, the supplier must pay the generator £2,000, i.e. the value of the agreed contract volume of 100 MWh at the contract price of £20/MWh. The different flows and the net positions of the Generator and Supplier in the case of a spot market price of 15 £/MWh are illustrated in Figure A.4.

Figure A.4
Settlement of CfD with 15 £/MWh Spot Price



In practice, the generator and the supplier settle only the difference between the generator's rebate and the supplier's payment, hence the designation of these agreements as "Contracts for Differences" or CFDs. Table A.3 shows how the difference amounts to a payment from the supplier to the generator of £500 (when the spot price is low) or a payment from the generator to the supplier of £1,000 (when the spot price is high). Given the payments associated with the spot market, the effect of these contractual payments is to leave the supplier paying, and the generator receiving, £2,000 in both cases.

Table A.3
Settlement of CFD in Two Cases

Payments	Case 1 Spot Price = £15	Case 2 Spot Price = £30
Generator owes Supplier	£1,500	£3,000
Supplier owes Generator	£2,000	£2,000
CFD: Net Rebate from Generator to Supplier	-£500	£1,000

A.7.2. Basis risk

CFDs of this type work well when both seller and buyer trade at the same spot price (or spot prices that are closely related such as the old Pool Purchase Price and Pool Selling Price that applied in England and Wales from 1990 to 2001). However, suppose that the spot prices in Table A.3 apply only at the node where the generator is located, and that the supplier is connected to a node where the price is, for simplicity, always £25/MWh. The supplier always pays the spot market £2,500 to take 100 MWh. In Case 1, the generator receives £500 from the supplier, so the supplier's total cost is £3,000. In Case 2, the generator pays £1,000 to the supplier, so the supplier's total cost is only £1,500. Hence, the supplier's cost still varies by £1,500. The supplier is exposed to the risk that the spot price ***to which the contract refers varies*** differently from the spot price ***that the supplier actually pays***. This risk is known as "basis risk".

In an electricity market with nodal spot pricing (LMP), traders are exposed to basis risk when the seller is connected to one node and the buyer is connected to another. Large traders and brokers can help others to manage this risk, by trying, where possible, to arrange CFDs that match generators with suppliers who are buying energy from the same node. Thus, if a generator at node A wants to sell to a customer at node B, a broker can arrange two CFDs:

- one CFD at price £X/MWh between the generator and another customer at node A and;
- another CFD at price £Y/MWh between the customer and another generator at node B.

This combination allows the broker to offer the generator and the customer a fixed price of £Y-X)/MWh for the "transmission" of power between them, thereby eliminating basis risk.

However, traders and brokers can never achieve a complete match, because some power always flows from generators at low price nodes to customers at high price nodes. To manage the basis risk associated with this net flow, the concept of "Financial Transmission Rights" was borne.

A.7.3. Financial Transmission Rights (FTRs)

As explained in section A.3.3, settlement of an LMP market leaves behind a financial surplus, due to the "buy-cheap-sell-dear" rule. The size of this financial surplus measures the degree of basis risk borne by the market as a whole. Financial Transmission Rights (FTRs) provide one means of returning this financial surplus to market participants in a way that helps them to manage this overall basis risk.

A Financial Transmission Right is like a contract for differences, but instead of referring to a single spot price, it refers to ***the difference between two spot prices***. Hence, suppose the market operator issued a single FTR to the supplier in our example above, for 100 MWh referenced to the difference between the two nodal prices. Assume that the FTR guarantees zero cost transmission from the generator's node to the supplier's node, so that the holder of this contract (the supplier) owes no contract payment to the market operator.[30] The only exchange of funds then concerns the market operator's rebate to the supplier.

In case 1, the price at the generator's node (A) is £15/MWh, whilst the price at the supplier's node (B) is £25/MWh. The difference between these prices is £10/MWh (which represents the marginal cost of moving electricity from A to B). Under the FTR, the market operator rebates this difference to the supplier for 100 MWh, a sum of £1,000.

In case 2, the price at the generator's node (A) is £30/MWh, whilst the price at the supplier's node (B) is still £25/MWh. The difference between these prices is ***minus*** £5/MWh (which implies a negative marginal cost of moving electricity from A to B). Under the FTR, the market operator ***receives*** this difference ***from*** the supplier for 100 MWh, a sum of £500.

Table A.4
Settlement of CFD and FTR in Two Cases

Payments	Case 1 Spot Price = £15	Case 2 Spot Price = £30
Generator owes Supplier	£1,500	£3,000
Supplier owes Generator	£2,000	£2,000
CFD: Net Rebate from Generator to Supplier	-£500	£1,000
FTR: Market Operator Reimburses Supplier	£1,000	-£500
Supplier's Net Receipts from CFD and FTR	£500	£500

Table A.4 adds the effect of this FTR to the settlement of the CFD set out above. In both cases, the combined effect of CFD and FTR is a net payment to the supplier of £500. When deducted from the cost of the supplier's spot purchases (100 MWh @ £25/MWh = £2,500), the supplier's net cost of purchasing 100 MWh of electricity is £2,000, at an average price of £20/MWh, in both cases.

Hence, FTRs work alongside CFDs to help market participants manage basis risk. Academic research into the properties of FTRs has shown that the market operator can fund payments under the FTRs out of the financial surplus of the nodal spot market, provided that the combined capacities of all FTRs together map out a feasible pattern of power flows sufficient to meet demand.[31] However, in practice, few electricity markets offer such comprehensive protection against basis risk.

30 This is one special case. The FTR might, for instance, require the holder to pay a fixed transmission fee in £/MWh, or to pay for the actual cost of losses on transmission from one node to the other.

31 See W.W. Hogan, ***Contract Networks for Electric Power Transmission***, Journal of Regulatory Economics, Vol.4, No. 3, September 1992. See also W.W. Hogan, ***Co-ordination for Competition in an Electricity Market: Response to FERC Docket No. RM94-20-000 of October 26, 1994***, John F. Kennedy School of Government, Harvard University, 2 March 1995.

The creation of such a comprehensive set of FTRs would require a detailed forecast of transmission system conditions, for all future periods, but most transmission systems vary considerably from hour to hour (so it is difficult to use average flow patterns for longer periods). Moreover, even if it were possible to define a pattern of power flows, it is not immediately obvious how to divide them up into separate FTRs covering power flows between two individual nodes. Some separation of power flows would be required to let many different market participants hold FTRs sufficient to cover their own basis risk (i.e. the pattern of their own purchases and sales).

Assuming that these problems can be overcome (or ignored), the market operator must decide whether to allocate FTRs to existing system users (as protection against the new basis risks to which they were not previously exposed) or whether to sell or auction the FTRs to the highest bidder. Auctions will raise additional funds from market participants, in return for stabilising future costs of transmission. However, it may not be efficient to give the market operator rights to issue FTRs for all transmission capacity, as it may conflict with the need to reward past investors in particular assets, as we explain below.

A.8. Investment Incentives

In any commodity market, spot prices do not play a primary role in determining long-term investments, which depend largely on long-term contracts and forward market prices. However, neither long-term contracts nor forward markets will provide efficient signals for investment unless they are underpinned by efficient signals in spot markets, such that traders who over- or under- invest bear the short-run cost of their mistakes. The desire to support incentives for efficient investment imposes some constraints on the design of electricity spot markets, and on the arrangements for planning, building and remunerating investment in transmission.

A.8.1. Generation

Investors in generation are used to reacting to spot, forward and contract prices for electricity. LMP markets only offer an additional dimension – the prices on offer vary by node within a single market, as well as between markets. As a result, LMP markets are intended to provide signals about the efficient location of new investment in generation, as well as the overall volume.

A crucial design question is the value to which nodal prices revert when a forced outage takes place at a certain node, because of a lack of generation capacity at (or transmission capacity to) that node. In such times, the price needs to rise to very high levels – the "Value of Lost Load" or VOLL – to indicate the value that consumers would place on having more generation (or transmission) capacity available to supply power to that node. Otherwise, the market will lack the short-term price signals needed to reinforce investment incentives.

In practice, such signals may be muted by problems of "lumpiness" and instability. In the whole generation market (provided it is relatively large), building one generator of about 200 MW need not cause prices to collapse from previously high levels, so investors can capture the benefits of investing at the right time. However, in small markets, or in nodal markets where prices depend crucially on local supply conditions, the addition of 200 MW at one node can sometimes radically reduce the price at that node, thereby removing any reward for investment. To overcome this problem, investors need to secure long-term contracts with buyers, at prices:

1. That are below forecast prices at the node, assuming no generator is built;
2. That are sufficiently high to cover the costs of the generator; and
3. That may (but need not) exceed actual prices at the node, once the generator is built.

Investors would need to secure such contracts before constructing the plant.

Since nodal prices may depend on production conditions in distant parts of the network, it is by no means a foregone conclusion that investment in one generator will cause prices to collapse locally. However, long-term contracts are a crucial component of risk management by any investor. To find a supplier or customer willing to sign a long-term contract, a generator may need to offer a contract whose reference price is the customer's nodal spot price, in which case the generator will be exposed to basis risk unless he can obtain a Financial Transmission Right for the route from generator to customer.

A.8.2. Consumption

Few consumers alter their location in response to variations in electricity prices, but some energy-intensive industrial customers might be encouraged to open or to close plant in different locations on the strength of forecast electricity prices. The estimated price elasticity of electricity demand (i.e. the extent to which electricity consumers adjust their demand when prices rise or fall) is relatively small,[32] although local variations in price will have some impact on general levels of demand over the long-run.

Once again, the "lumpiness" of such changes in demand may affect prices, but only a very few consumers are prepared to sign long-term contracts for their energy supply. Most consumers sign contracts for only a year or two and are prepared to revert to market prices after that time.

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32 Conventional estimates of price elasticity of demand for electricity range from about 0.1 to about 0.25, depending upon the timescale over which demand is allowed to change. Over longer periods, demand responds more. These figures are relatively low, given that the standard boundary between "elastic" and "inelastic" demand is a price elasticity of 1.0.

A.8.3. Transmission

An important motivation for introducing LMP pricing into electricity markets is to provide price signals that encourage efficient ***decentralised*** decisions about investment in transmission. As stated in section A.7.3, the difference between two nodal prices represents the marginal cost (or spot price) of moving electricity from one node to the other. If this price difference rises to very high levels, it would be efficient to add transmission capacity.[33] The fact that market participants are paying the spot price of transmission (i.e. nodal spot price differences) gives them the same incentive to invest efficiently in transmission, as single spot prices provide for investment in generation.

There has been much academic debate about the most efficient regime for encouraging decentralised investment in transmission. A consensus seems to have emerged around the following model of LMP markets:[34]

1. Generators receive, and customers pay (or rather, their suppliers pay), the nodal spot price (LMP) at their node of connection, for all their output or consumption.
2. The system operator receives the financial surplus resulting from settlement of the LMP market;
3. The system operator allocates tradeable FTRs either to owners of transmission assets (in relation to the transmission capacity made available by their investment), or directly to users of transmission capacity (in relation to some measure of historic or forecast usage);
4. Anyone who builds new transmission assets receives additional FTRs for the capacity created by the investment (including, in principle, negative FTRs for any transmission capacity that the investment destroys).

The process in Point 3 requires a central model of network capacity that allows independent assessment of the contribution made by any single investment, using forecast data on production, consumption and network characteristics. Such a central authority is needed to establish basic property rights, because individual investments in transmission affect one another – a feature of network planning known as "network externalities".

The mechanism in Point 4 gives anyone who builds a transmission asset the right to receive the spot value of the transmission capacity they create (less the spot value of any transmission capacity they destroy). The receipt of this payment provides the same kind of

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33 If price differences are very low, or even zero, it might be efficient to remove transmission capacity, but normally the costs saved by doing so are trivial, so closure offers no efficiency gain. If the price differences are negative, i.e. if power is flowing from high price nodes to low price nodes, it would usually be efficient to remove some transmission capacity, but the system operator can normally achieve such efficiency gains by opening switches, rather than by dismantling whole power lines.

34 This "consensus" represents our synthesis of the writings of Bill Hogan and of a debate that continued for several months in the Electricity Journal during 1996.

incentive to invest as the spot price for energy gives to generators. As with generation capacity, investors would probably seek some long-term stability of revenues by selling off long-term financial contracts covering their transmission capacity – i.e. FTRs - to traders who want to protect themselves against the associated basis risk. As with generation capacity, investors would need to secure such contracts before constructing the transmission assets, in case the investment caused a subsequent collapse in the value of transmission (i.e. a reduction in price differences between two nodes).

Despite the focus on decentralised investment, this scheme still requires a central authority to define the capacity created or destroyed by any investment and to authorise the issue of FTRs by the system operator to the investors. No-one has been able to establish how a completely decentralised, de-regulated market in transmission could work efficiently, because of the interactions between investments known as network externalities.

In practice, this academic approach to transmission investment planning may only be of interest in large, fragmented transmission systems characterised by long lines between distant population centres, such as those found in the United States. Here, there is no monopoly over transmission and investments take the form of discrete additions to transmission lines. Some means is needed to coordinate multiple investors and the consensus view set out above might work better than existing systems. After all, the existing system of planning transmission in the US has been accused of discouraging efficient investment and even of causing the recent black-out in the north-eastern states.

In the dense “meshed” transmission networks of Western Europe, network externalities are more difficult to identify and usually one company possesses a historic or de facto monopoly over transmission within any area. Here, the prospect of decentralising decisions about investment in transmission seems a distant one. Instead, electricity transmission companies remain regulated utilities, whose incentives depend on regulatory price formula, and whose regulated income tends to match their costs, not the value of their investments.

In such conditions, transmission companies have little or no incentive to respond to the price signals offer by LMP markets. LMP prices may provide some indication of a short-term need for investment or repairs to restore capacity that is out of action due to a breakdown – especially if the transmission company issues FTRs and so is liable for the short-run cost of any short-fall in transmission capacity. However, regulated monopolies will continue to plan long-term investment in capacity additions by reference to long-term forecasts, standard planning procedures, and regulatory incentives.

A.9. Conclusion

In each period, Locational Marginal Pricing systems (or “nodal spot markets”) use complex computer algorithms to produce different electricity prices for each “node” where electricity enters or leaves a transmission network. The outcomes of these LMP systems differ from single price or "zonal" markets significantly, although not necessarily in the way that one might expect.

The price at each node equals the increase in costs brought about by an increase in demand at that node. Demand increments at one node may be supplied by increasing generator output at more or less distant nodes, which may be hard to predict or even to identify. As a result, the derivation of prices sometimes lacks transparency, compared with a zonal market that sets prices by simply matching offers and bids (or just by stacking offers to meet demand). LMP systems are a "black box".

In principle, the calculation of a different price for each node provides the most information about the value of generation and load at different points (and of transmission capacity between different points), thereby encouraging the most efficient decisions. In practice, other considerations may lead to pressure for prices to be averaged over zones, especially for load, although the technical arguments in favour of nodal pricing have been growing in strength over time.

The choice of a nodal, rather than zonal, market does not necessarily increase market power. Nodal prices do not depend only on the offer prices of generators at (or even close to) the node in question, so setting the price on a nodal basis is not equivalent to restricting the size of the market. A generator with market power in the market as a whole will usually be able to exercise market power whether the market is zonal or nodal. Generators with "local market power" due to a transmission constraint may have a bigger effect on prices in nodal or zonal markets than in an LMP market, depending on circumstances and detailed pricing rules.

Given the variability of spot prices, generators, traders and suppliers will normally use financial contracts to stabilise payments between them. Since generators may be selling power at different prices from those charged to consumers, they face an element of "basis risk" which can only be partially solved by brokers and portfolio traders. To eliminate basis risk entirely, the system operator (or some other body) would need to issue a set of Financial Transmission Rights – i.e. financial contracts that offer protection against variation in the ***difference*** between two nodal prices. A set of FTRs whose capacities match a simultaneously feasible dispatch can be financed out of the financial surplus left in the LMP market after settlement of claims and obligations.

In theory, FTRs can also provide a means to reward investors in transmission capacity, if the system allows multiple transmission investors to respond to observed or forecast differences between nodal prices. However, the operation of such a system is complex and requires a central authority to define capacity additions and allocate FTRs. Most transmission networks continue to rely for investment on the centralised planning procedures and regulatory incentives of monopoly utilities.

This outline of nodal spot markets in theory and practice illustrates some of the compromises made in implementing LMP systems. As the following case studies show, any

LMP system will apply the principles in a particular way and will differ from other LMP systems according to local requirements and conditions.

APPENDIX B. CURRENT TRADING ARRANGEMENTS

In this appendix, we summarise the technical details of the current trading arrangements for the following:

- NI wholesale market;
- North-South interconnector trading; and
- Moyle interconnector trading.

B.1. NI Wholesale Market

The Interim Settlement Code, version 3.0, 26th March 2003, sets out the trading and settlement arrangements in force in NI. Below is a summary of the provisions of the Interim Settlement Code.

- Standing data

Participants are required to provide relevant standing data to NIE no later than 10 Business Days before it first proposes to participate in the trading arrangements. Participants must keep standing data accurate and complete.

- Nominations

Participating Generators must make nominations for each of their Generating Units for a Trading Day by 11:00 hours on the previous Trading Day ("Gate Closure"). Their Nominations must notify NIE of their intended supply to each Participating Supplier, which NIE uses to determine the Local Demand Nomination of Participating Suppliers. The process for interconnector nominations is explained in the following section.

In addition to their Generating Unit nominations, Participating Generators may submit to NIE a Supplemental Energy Bid (to sell electricity to NIE on a Trading Day) before Gate Closure for the Trading Day. The bid format includes a start-up price, a fixed price, and an incremental price – a format which is sometimes characterised as "complex".

If required by NIE, Participating Suppliers must also provide NIE with their best estimate of expected demand for each Settlement Period of the Trading Day before Gate Closure.

VIPP capacity holders must notify NIE of the electricity to be supplied to the VIPP capacity holder under its VIPP Capacity and Energy Agreement for each settlement period in the Trading Day before Gate Closure.

After Gate Closure, Participants cannot change Trading Data for a Trading Day without either the consent of NIE or under certain conditions set out in the Code. NIE reviews Trading Data to check compliance with the requirements of the Code. NIE may reject Nominations that do not comply with the Code and where NIE decides that it would be unable to dispatch in accordance with the Nomination because of constraints on NIE's system or on the interconnectors.

- Settlement

NIE sends settlement statements to Participants within 15 business days of the end of each Payment Period (which starts 06:00 hours on the first day of each calendar month and ends at the end of the last Trading Day of that month). NIE issues invoices to Participants for each Payment Period, based on the relevant settlement statement.

Payments arising from Demand Errors[35] for Participating Suppliers will either be a Supplier Spill Payment (if the Demand Error is positive) or a Supplier Makeup Charge and a Makeup Capacity Charge (if the Demand Error is negative). The Supplier Spill Price varies by season and tolerance (ie there are summer and winter prices for demand errors within tolerance and outside tolerance).

Participating Generators make (or receive) payments in the event of dispatch errors[36] and for over or under nomination. Supplemental energy payments (ie for dispatch over nomination) depend on the generating unit's incremental price, the start up price, the fixed price and the unit spill price (which is different from the Supplier Spill Price mentioned above). Under nominations payments are made at the generating unit's nominal fuel price. The unit spill price varies by season and tolerance.

In addition to the above, Participating Suppliers pays NIE a system charge for each Settlement Period (which includes the public service obligation, as specified by NIE in the Bulk Supply Tariff), and each Participant pays NIE a capacity charge in respect of each Trading Year (which is defined as the a Participant's chargeable peak demand multiplied by their Capacity Rate).

B.2. North-South Interconnector Trading

Third-party trade on the North-South interconnector is governed by an agreement between SONI and the Transmission System Operator (TSO) in the RoI, currently ESB National Grid (ESBNG). Under that agreement, the Settlement System Administrator (SSA) in the RoI, a role currently performed by ESBNG, manages the process for trading across the North-South interconnector, including superposition. The SSA has set out in ***Agreed Procedure No.***

35 Demand Errors are Local Demand Nominations (plus adjustments) less Actual Demand (plus adjustments).

36 Dispatch errors are defined as the difference between Dispatched Output and Actual Output.

06 (AP06) the process to which all users of the Louth-Tandragee interconnector must comply, regardless of whether the party is located in the North or South. Below we summarise the process as set out in ***AP06***.

To submit nominations for trading across the interconnector, parties must be registered interconnector parties. In the North, this means parties must be party to the Interim Settlement Agreement and must have registered with SONI specifically for trading on the interconnector (and SONI in turn will furnish ESBNG SSA with relevant information). In the South, this means parties must be party to the Trading and Settlement Code.

For Northern participants, SONI handles all trading registration enquiries. For new participants, SONI supplies SSA with a completed registration form 5 business days before the party commences trading on the interconnector.

- Process

SONI and ESBNG agree the expected Net Transfer Capacity (NTC) of North-South flows and South-North flows between them. By ***10:00 hours on D-3***, the TSO publishes the expected NTCs for each half-hour period of a Trading Day (D) on Eirgrid's website.

Interconnector parties' nominations to trade must be submitted to ESBNG SSA electronically, in a pre-specified format, no later than ***12:00 hours on D-2***, although in the event of a failure in electronic communication, faxed notifications will be accepted by prior agreement. Nominations received after 12:00 hours on D-2 will be rejected. All nominated trades[37] and nominated matched trades[38] are binding for the purposes of allocation.

By ***16:00 hours D-2***, ESBNG SSA determines the allocation of trades for all interconnector parties. Parties in the North and South are sent an email containing details of the trades to be allocated to each interconnector party in either a North-South or South-North direction.

- Assignment of Capacity Entitlement

Interconnector parties can acquire Long Term Contracted Capacity Entitlement (LTCCE) through signing up to an Interconnector Auction Agreement in the Republic of Ireland or relevant agreement in Northern Ireland.

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[37] The agreed procedure defines a nominated trade as a request from an interconnector party for a trade to be assigned between themselves and another interconnector party in a trading period in a North-South or South-North direction.

[38] The agreed procedure defines a nominated matched trade as a request from an interconnector party in a trading period for an amount of trade in a given direction which is matched by an equal amount from another interconnector party in the opposite direction to be considered in the superpositioning process.

Holders of LTCCE can assign the entitlements for the purpose of allocating trades under the superpositioning mechanism to any interconnector party. SONI manages the process for entitlements in the North-South direction and ESBNG SSA manages the process for entitlements in the South-North direction. If a party's aggregate assignment exceeds their entitlement under the Interconnector Auction Agreement (or equivalent), the entitlement will be considered to only apply to the original interconnector party. Assignment of LTCCE must be made under the terms of the relevant Interconnector Auction Agreement.

- Validation

A ***nominated trade*** becomes a validated trade if the submitted nominations of the Northern party and Southern party concur in direction and amount. In the event they do not concur, the nominated trade is not validated and is set to zero.

A ***nominated matched trade*** becomes a validated matched trade if the nominations of the Northern party and the Southern party meet the following conditions:

- the parties have consented in their nominations to "***identical amount of matching of their trades in the respective directions***"; and
- the total amount of matching allowed for a participant in a given trading period cannot exceed the aggregated validated trades for that interconnetor party in that direction for that period.

If either condition is not met the nominated matched trades are not accepted.

- Allocation

If the net flow in a trading period is ***less than*** the NTC value for that period in the dominant direction, all validated trades in both the dominant and non-dominant direction are accepted.

If the net flow in a trading period is ***greater than*** the NTC value for that period in the dominant direction, then allocation will occur as follows:

- All validated trades in the non-dominant direction and all validated matched trades in the dominant direction are allocated.
- If there is sufficient capacity, all remaining unserved validated trades in the dominant direction up to but not exceeding the NTC are allocated. If there is not sufficient capacity remaining unserved long-term validated trades in the dominant direction up to but not exceeding the LTCCE are allocated on a pro-rata basis.
- Any remaining unserved validated trades are allocated on a pro-rata basis with respect to remaining NTC in the dominant direction.

- If an interconnector party has multiple trades with different users and has insufficient allocated trades in the dominant direction the individual trades are pro-rated.

- Within-day Rationing

In the event that there are changes in the NTC after the deadline for nominations, the SSA may reallocate trades.

- In the event that NTC is reduced, all allocated trades in the non-dominant direction will be allowed and all allocated trades in the dominant direction will be pro-rated to facilitate the reduced NTC.
- In the event that NTC is increased, all validated trades will not be reallocated.

- Interconnector usage charge

In the event that an interconnector party is allocated a trade in excess of its long-term capacity rights, it is liable to pay SONI, for North-South flows, or ESBNG, for South-North flows, an interconnector usage charge. Interconnector parties with LTCCE will pay interconnector charges as set out in the relevant Interconnector Auction or Capacity Agreement or as outlined in the Statement of Charges. In addition, they are liable for a charge of EUR 0.66/MWh for their short term trade (or such charge as is determined by SONI in agreement with Ofreg for North-South flows or as determined by TSO in agreement with CER for South-North trades).

B.3. Moyle Interconnector Trading

The arrangements for trading across the Moyle interconnector are set out in the Interim Settlement Code for NI.[39] These are summarised below.

For each transfer, the Interconnector Capacity Holder (ICH) must identify one Source and one Sink. The ICH must be either the Source or the Sink. A Source or Sink that is not the ICH is known as the Interconnector User (IU). When the ICH or IU is a licensed supplier in NI, it is obliged to have arrangements in place with generator/s in the interconnected system to make good any shortfalls in generation, thereby ensuring that the Import Nomination flow across the interconnector is met.

The ICH and IU must sign all import nominations and export nominations. Only an ICH can submit a nomination for import and/or export and to transit power the ICH must have the right under Interconnector Capacity Agreements.

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39 Interim and Settlement Code (version 3, 26 March 2003).

A capacity holder's nominations for the Moyle interconnector must not exceed its entitlement.

Gate Closure for nominations to the Moyle Interconnector is 11:00 hours on D-1 (ie later than for trade on the North-South Interconnector).

Each ICH must notify NIE of the kWh of electricity to be imported into (and transited across) NI ("Import Nomination") and the kWh of electricity to be exported from NI ("Export Nomination") for each settlement period in the Trading Day. The ICH must make separate import nominations and export nominations for each IU involved in a transfer.

In addition to being signed by the ICH and IU, import nominations must:

- identify each licensed supplier to whom the electricity is to be allocated and specify the amount to be allocated to each ("Import Allocation");
- specify the amount (if any) of electricity to be transited out of NI during each settlement period ("Transit Allocation"), and the person to be supplied; and
- meet the requirement that Import Nominations in each settlement period equal Import Allocations and transit allocations.

In addition to being signed by the ICH and IU, export nominations must:

- identify each "Participating Generator" or "VIPP Capacity Holder" to whom the electricity is to be allocated and the specify the amount to be allocated to each Participating Generator ("Export Allocation") and VIPP Capacity Holder ("VIPP Export Allocation");
- in the case of Participating Generators, the amount to be allocated to each of its units ("Export Unit Allocation"); and
- meet the requirements that: (1) the sum of Export Allocation and VIPP Export Allocation equals the amount of Export Nomination; and (2) the sum of Export Unit Allocations equals the amount of Export Allocation to the relevant Participating Generator.

APPENDIX C. CBT DIRECTIVE

On 13 March 2001, the European Commission published a proposal for a regulation of cross-border exchanges. Amendments were made to that proposal on 7 June 2002.

On 26 June 2003 the Regulation (EC) No 1228/2003 of the European Parliament and the Council on ***Conditions for Access to the Network for Cross-Border Exchanges in Electricity*** was adopted and published in the Official Journal of the European Union.[40]

The main elements of this regulation concern Inter TSO compensations (1), determination of network access charges (2) and principles of interconnector capacity allocation (3).

1. Transmission System Operators are to be compensated for additional costs[41] incurred by hosting cross border flows of electricity on their network. The TSOs of systems from which the flows originate and/or end pay compensations to the TSOs that see the flows transit through their network. In order to recuperate the payments made to finance the compensations TSOs must adapt their national tariff systems.

2. There should be no specific tariff paid by exporters/importers in addition to general charges for access to the national network. In other words, the network access charges applied to generators and consumers shall not depend on the countries of origin or destination of electricity. Furthermore network access charges should not be distance-related. Most network costs should be mainly recovered through charges imposed on consumption. A smaller proportion of the total costs can be recovered from generation.

3. The regulation stipulates that a market-based solution that gives efficient economic signals to market operators and TSOs shall be applied for allocation of interconnection capacity. The market-splitting[42] mechanism adopted in the Nordpool is envisaged as the model for the EC. Additional revenues resulting from interconnector capacity allocation cannot be used for extra profits[43] but instead for guaranteeing availability, increasing capacity.

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40 http://europa.eu.int/eur-lex/pri/en/oj/dat/2003/l_176/l_17620030715en00010010.pdf

41 Costs are calculated by comparing the long run average incremental costs

42 The market-splitting mechanism determines the optimal use of interconnection on the basis of a comparison of market prices in each of the interconnected markets concerned.

43 New interconnectors can be exempted from this condition under specific conditions.