

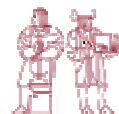
# ***Cambridge Working Papers in Economics CWPE 0442***



UNIVERSITY OF  
CAMBRIDGE  
Department of  
Applied Economics

## **Integrating Energy Markets: Does Sequencing Matter?**

***Karsten Neuhoff and David Newbery***



The  
Cambridge-MIT  
Institute

*Massachusetts Institute of Technology  
Center for Energy and  
Environmental Policy Research*

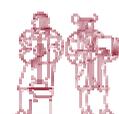
## ***CMI Working Paper 48***

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# Integrating energy markets: does sequencing matter?

Karsten Neuhoff and David Newbery\*

July 20, 2004

## Abstract

*This paper addresses three questions that are relevant to integrating different regional transmission areas. Market integration normally increases the number of competitors and should therefore reduce prices but the first section shows that prices could rise when the number of generators initially increases. Regulatory effort will also be affected by market integration. If the number of generators in either market is low, then our analysis suggests that the outcome depends on whether the regulators act independently or coordinate. Finally, if markets are gradually combined into larger units, the choice of transmission allocation (auctions or market coupling) will affect the prospects of making further gains and hence could lead to incomplete reform.*

## 1 Problems in the evolution towards competitive markets

In 1990 the Central Electricity Generating Board (covering generation and transmission in England and Wales) was restructured to separate out transmission (as the National Grid Company) and three generation companies: National Power, PowerGen, and Nuclear Electric. All except Nuclear Electric were privatized, although the modern stations of Nuclear Electric were subsequently sold as British Energy in 1996. Nuclear Electric, as its name suggests, contained all the nuclear power stations: the aging Magnox stations, the more modern Advanced Gas Cooled Reactors, whose earlier troubled history of delays appeared to have ended around 1990, and one PWR under construction. All these nuclear plant were inflexible and ran on base-load, while the fleet of mainly coal-fired power stations were divided in the ratio of 5:3 between the other two fossil-based generating companies. As these set the price 99% of the time, it was feared that the

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resulting duopoly would have the market power to result in excessive prices (Green and Newbery, 1992).

In the event, wholesale prices did not increase much in real terms in the first three years, although the price-cost margin gradually widened as coal costs fell and performance improved. Initially essentially all output was covered by vesting contracts (i.e. contracts written to take effect from the date at which the companies were formed), removing the incentive to bid up spot prices in the Electricity Pool (Newbery, 1995, 1998; Green, 1999). Over time these contracts lapsed and were replaced by new, freely negotiated contracts that might have been expected to reflect the significant market power of the duopoly. Indeed, as old contracts expired and new ones were signed, two major events signalled the dramatic change in market structure and conduct that privatization had set in train. The first, in 1993, was the ending of the coal contracts with British Coal, and a resulting crisis in the coal industry as it became clear that gas-fired combined cycle gas turbines offered an attractive vehicle for entry into a prospectively very profitable industry. The second, in 1994, was the finding by the Office of Electricity Regulation, Offer, that the price-cost margin had risen above the level consistent with a competitive wholesale market. Offer imposed a price cap for two years to allow time for the industry to propose a remedy, and in 1996 the two companies sold 6,000 MW of coal-fired plant to Eastern Electricity (subsequently TXU). Despite the resulting considerable decrease in concentration (e.g. as measured by the Herfindahl Hirschman Index, or HHI, equal to the sum of the squared percentage market shares), the price-cost margin remained stubbornly high, and continued to attract regulatory concern, investigations, blocked attempts at vertical integration, and eventually, substantial horizontal divestiture in exchange for vertical integration with supply (Newbery, 2000).

Green and Newbery (1992) had extended Klemperer and Meyer's (1989) theory of supply function equilibria to deal with time varying demand in the Electricity Pool. They examined the range of feasible equilibrium outcomes to demonstrate the importance of market power. There is some evidence that before 1994, each company was bidding each level of output at a lower price than would be profit maximising. Andrew Sweeting (2001) drew on this theory to examine bidding behavior in the Electricity Pool from 1995, asking whether each players' bids were profit maximising given the bids of the other player(s). He found that after 1996, when 6000 MW of plant had been sold, the larger number of companies were bidding in accordance with their individually rational pursuit of profit. Later, after further divestiture, it appeared that bids were higher than might be expected to be individually profit maximising - in short, there was some evidence of tacit collusion to sustain a collectively more profitable outcome. Once fragmentation passed a critical point, however, the price-cost margin collapsed, several companies became technically or actually bankrupt (including British Energy, which was preserved only by

a Government loan).

The experience of the evolution of electricity prices in Britain suggests that the link between competitiveness (measured by the price-cost margin) and market structure is not simple. Figure 1 shows the yearly moving average real wholesale price of electricity and the generation fuel cost on the left had scale. The line with diamond markers gives the concentration of price-setting coal-fired plant on the right hand scale, measured by the HHI, showing the two periods of deconcentration. The issue becomes particularly important in two practically relevant circumstances -

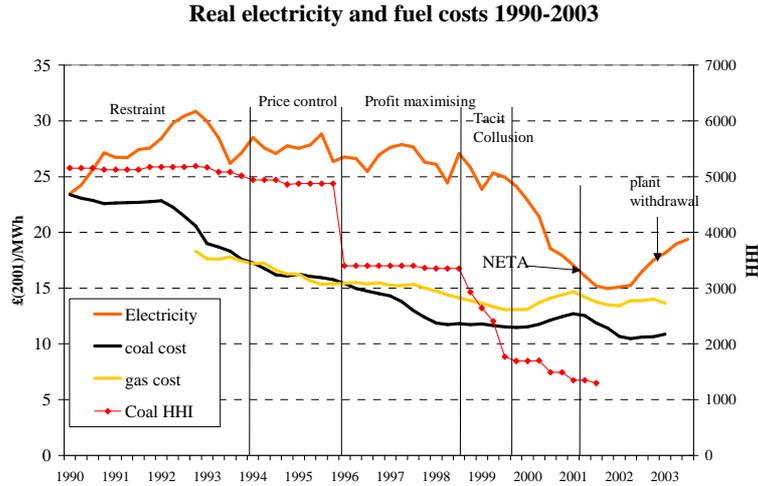


Figure 1: Impact of market concentration on wholesale price.

policy-imposed restructuring to increase competition starting from a very uncompetitive structure, and market integration, where a more competitive country combines its market with a less competitive neighbor. The case of integrating the Benelux market is a case in point, for while the Netherlands has four comparably sized generation companies, Belgium has a single company that in addition owns the largest Dutch generation company.

Standard market analysis based on Cournot competition would always show that dividing capacity among a larger number of companies in the same market would reduce prices, just as would combining two markets with the same set of previously isolated companies. A number of countries are concerned at the degree of concentration in generation and are either requiring divestiture (as in Italy) or temporary divestiture (virtual power plant auctions in France and Belgium). In other countries such as the Netherlands, competition authorities have required plant divestiture as a price for approving mergers. The European Commission is pressing for improved market integration, through improved access to interconnectors as well as additional investment in interconnector capacity, again with the expectation that integration will lower

market power and improve market performance. If, instead, a modest increase in competition results in initially higher prices, then liberalisation may fall into disrepute (as happened in the US after the Californian debacle), and economists may lose the confidence of policy makers.

This paper discusses possible explanations of the apparently perverse relation that may appear between concentration and price-cost margins (at high levels of concentration), to help understand the dynamics of market restructuring better. We need to know whether such a perverse relationship reflects important market fundamentals or merely a disequilibrium evolution, - the fallacy of *post hoc, ergo propter hoc*. There would seem to be several possible reasons why an increase in the number of competing firms might lead to higher price-cost margins, and the paper provides suggestive models setting out the conditions under which this might happen. The first reason draws on the standard legal approach to competition policy, under which holding a monopoly position is not illegal, but abusing that position is. A sensible monopoly would therefore exercise restraint when under the surveillance of a regulatory agency.

Many jurisdictions consider that market surveillance is particularly important for the electricity supply industry, given the special features of its product: very inelastic demand in the short run, inability to store the product and hence little intertemporal elasticity of substitution, durable, sunk and capital-intensive plant making transient entry unlikely, and transmission constraints that fragment markets. There are additional reasons in the US for such market surveillance, where the Federal Power Act of 1935 requires that electricity prices be “just and reasonable”, implying the need for constant monitoring of prices to ensure compliance.

Electricity companies with market power will therefore exercise a degree of price restraint when bidding plant into wholesale spot markets, depending on the extent to which they could be accused of having and exercising market power. Given that the resulting market clearing price will depend on the price-quantity bids of all participants, the larger the number of bidding generators, the harder it will be for the regulator to assign blame for market manipulation, and the less plausible will be the claim that the individual generator had significant market power (normally taken to be at least 25% and sometimes as much as 40% of the market). The difficulty to detect exercise of market power is well illustrated at the California example. Borenstein and Bushnell (1999) use a Cournot approach to analyse the potential for market power in California. Joskow and Kahn (2002) show, using the example of California’s summer of 2000, that simulated competitive benchmark prices are below observed prices. Harvey and Hogan (2002) repeat the simulations and run sensitivity analysis on the parameter choices. For some of their parameter combinations, simulated prices reach observed prices. Assessing generation output, Joskow and Kahn (2002) calculate that unilateral withholding of output to push up the wholesale price would have been profitable for portfolio generators and, indeed, observe that “either the units

[of portfolio generators] were suffering from unusual operational problems or they were being withheld from the market to increase prices.” The first set of models below attempts to capture the implications of difficulties to monitor market power.

The second set of reasons has to do with the public good of entry prevention. If a monopoly incumbent wishes to continue a quiet life, then pricing just below the average cost of new entry may deliver the joint benefits of non-abusive behavior and entry deterrence. By itself this would be consistent with a contestable and hence efficient market, but in the presence of excess capacity, such pricing would be above the efficient and competitive level. Nevertheless, it would be the result of a dynamic disequilibrium, to be corrected as the market tightens and new investment is required. Inefficiency would then require the incumbent to deter entry while extracting some monopoly rents - for example by monopolising the balancing market, making it unpredictable and illiquid, and/or by vertical integration into supply, making the contract market illiquid to raise the risks and hence costs of entry. The appropriate regulatory action would be to reduce entry barriers, perhaps by allowing independent supply companies to build and contract for competitively tendered new capacity. Meanwhile, during the period of excess capacity, a move to divest capacity and create more competitors may reduce the individual benefit that any single company derives from entry deterrence. The balance of short-run profits from higher prices against greater long-run competition from entry may then favour temporarily higher price-cost margins as concentration falls. This explanation would be a dynamic disequilibrium story, with a more satisfactory long-run equilibrium but a period in which regulators and/or politicians might lose their nerve if they failed to appreciate the underlying dynamics.

The first model captures the phenomenon illustrated in Figure 2, where splitting a monopolist into a two firms could result in a price increase.<sup>1</sup> The model includes the regulator as an additional player, whose monitoring effort required to detect market abuse increases with the number of firms under surveillance. Given that, the regulator will have to balance the costs of monitoring against the gain. The efficient response is to reduce the monitoring effort per firm until the marginal cost of additional monitoring equals the marginal benefit of more competitive electricity prices.

The same model can be adapted to address the case where the markets in two neighbouring countries are to be integrated. On the reasonable assumption that each country retains its own regulatory and competition authority, and can only properly monitor the company located within its own country, market integration will cause both regulators to reduce their monitoring efforts for two reasons:

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<sup>1</sup>The mark-ups are calculated used ICF’s consulting model to determine competitive prices and Heren data for month (UK week) ahead base load contracts in the year 2002.

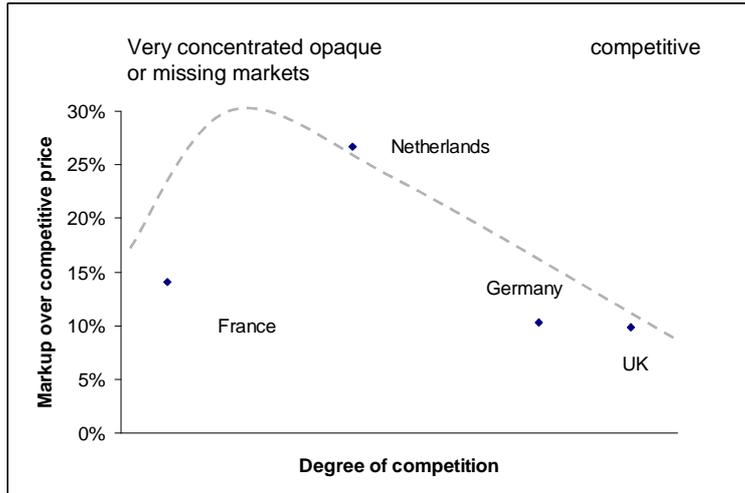


Figure 2: Is there a non-monotonic link between concentration and markup?

1) The regulatory authorities are only assessing the impact of their regulation on their home consumers, and so will not take account of the externality on consumers in the other country. At the same time in the joint market, the impact of the decision of any one monopolist on the home consumers is reduced, leading the regulator to reduce its effort.

2) The regulatory authority will attach weight mainly to the benefits of the domestic utility (e.g. jobs, tax paid, informal connections), and hence continue to have the incentive to reduce regulatory interference.

In both cases the reduced monitoring effort is counterbalanced by increased competition, which reduces the incentive for the dominant players to exercise market power. The model shows that the net effect depends on the relationship between regulatory effort (cost) and monitoring/enforcement success.

The outcome could be improved by delegating oversight of the combined market to a joint regulatory authority, in which case it would internalise the externality on customers in neighbouring countries. This joint authority could be charged to maximise combined welfare (or, equivalently, consumer welfare subject to a financially sustainable electricity industry). The only difference compared to the two individual cases is that the level of competition is increased and hence the dominant generators are less inclined to exercise market power. This suggests that the price level should fall. The question remains whether a joint regulatory agency could be implemented, and whether it would indeed maximise joint social welfare.

## 2 Divestiture within one market

Assume  $n$  firms are supplying a market at constant marginal costs, normalised to zero. Demand in the market is linear, characterized by:

$$d = D - bp. \quad (1)$$

We assume a game of three periods. In the first period the generators sell electricity to consumers in a Cournot game. However, they anticipate the potential intervention of the regulator when deciding on their output quantity and hence on the market clearing price. In the second period the regulator determines whether to monitor/enforce low contract prices and how much effort to devote to this. The known objective function of the regulator is the minimisation of electricity prices (or the price-long-run marginal cost margin) and the expenditure on market monitoring and investigation.<sup>2</sup> The regulator can spend more and increase the likelihood  $\rho$  with which he will detect the exercise of market power and successfully force companies to lower their price. (Equivalently, the regulator may be able to impose a fine after a successful court case.) The relationship between the likelihood of success and the cost in terms of effort, political credibility and consulting/legal fees is given by the cost function,  $R\rho^2$ . In the third period the regulator succeeds in an investigation with probability  $\rho$ . In the case of success prices are lowered to a margin  $m$  above marginal costs. This reflects the fact that information asymmetry prevents the regulator from determining the exact marginal costs of an efficient generator, but has to set the price according to the cost structure of potentially inefficient oligopolists.

The game is solved backwards. The expected price in period three paid by consumers equals the weighted average of contract price negotiated in period  $p_1$  one and the margin  $m$  above marginal cost (which is normalised to zero):

$$E[p_f] = (1 - \rho)p_1 + \rho m. \quad (2)$$

In period two the regulator chooses the probability  $\rho$  of successful ex-post intervention in the sales price of any one generator. As there are  $n$  generators and as each will have to be investigated, the regulator's objective function is to:

$$\max_{\rho} -E[p_f(\rho)] - nR\rho^2. \quad (3)$$

The first order condition gives:

$$\rho = \frac{p_1 - m}{2Rn}. \quad (4)$$

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<sup>2</sup>This is intended as a reduced-form representation of the regulator's problem of allocating his limited budget to market monitoring and other regulatory functions such as setting network price controls, and reflects the trade-off between regulatory cost (direct and due to possible losses of regulatory stability and credibility) and consumer benefit.

In period one the oligopolist generators determine their output quantities  $q_i$  to maximise profits (which with zero normalised cost is equal to sales revenue). They anticipate that the regulator will renegotiate the contracts with probability  $\rho$  which is a function of the spot price.

$$\pi_i = \left[ \frac{D - (n-1)q_j - q_i}{b} (1 - \rho) + \rho m \right] q_i. \quad (5)$$

Using the first order condition we can calculate that each generators' chosen level of output is:

$$q = \frac{2(n+1)(F - Rbn) + \sqrt{4(n+1)^2(F - Rbn)^2 + 4n(2+n)(2RbnD - F^2)}}{2(2+n)n}, \quad (6)$$

where  $F = D - bm$ . Substituting  $d = nq$  where  $q$  is given by (6) into (1) gives the period one price  $p_1$ . The regulator will only intervene if  $p_1 > m$ . The probability of successful intervention/regulation is then given by (4).

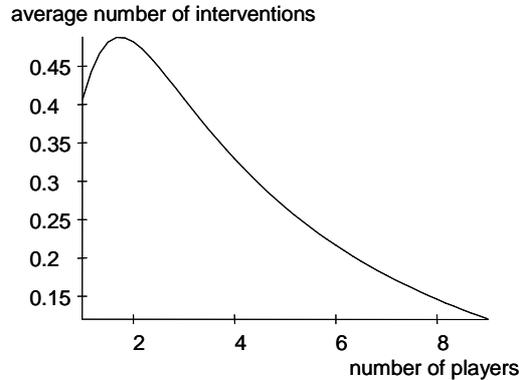


Figure 3: Successful interventions on wholesale price as function of concentration.

Figure 3 shows that in equilibrium there will be more successful interventions overall with two firms, but fewer per firm. However, given the assumed relation between costs and the success rate, Figure 4 shows that total monitoring cost is strictly decreasing in the number of players.

Finally, Figure 5 gives the usual Cournot oligopoly price (top line), the price charged by generation companies in period one (middle line), and the expected average price taking into consideration the probability of regulatory intervention (bottom line), showing that it is indeed possible for the price-cost margin to increase as the industry becomes less concentrated, although once the number of competitors increases beyond three, prices begin to fall again.<sup>3</sup>

### 3 Combining two markets

Next, consider the case in which two markets are integrated and firms in both markets sell in both regions  $k$ , but under the existing and separate regulators. Both regions are symmetric, and

<sup>3</sup>The numerical illustrations are based on the following parameter values:  $D = 10, b = 1, R = 2, m = 0.5$

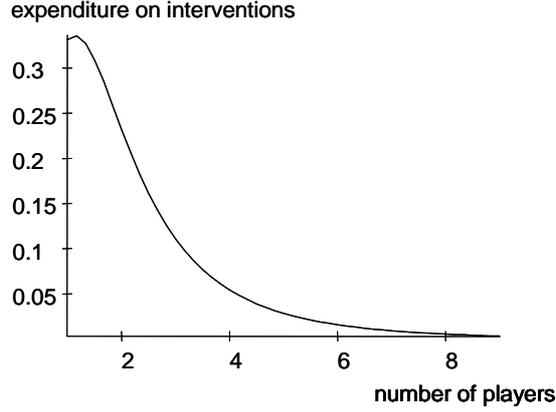


Figure 4: Expenditure on market monitoring as function of concentration.

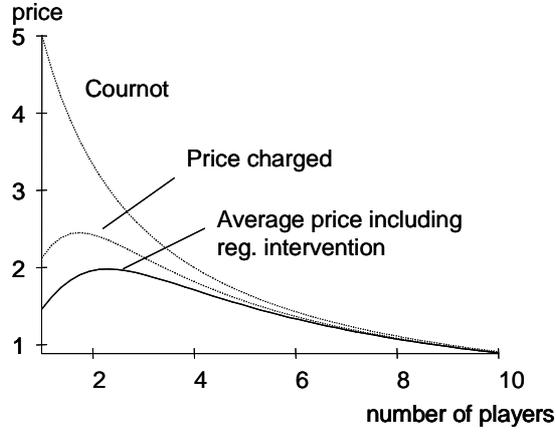


Figure 5: Model results for average wholesale price.

so the expected regional price is:

$$E[p_f] = \frac{1}{2} \sum_k ((1 - \rho_k) p_{1,k} + \rho_k m). \quad (7)$$

In period two the regulator in region  $k$  chooses monitoring effort and hence the success probability  $\rho_k$  of ex-post lowering the price at which a generator sold energy to maximise his objective function:

$$\max_{\rho_k} -p_{f,k}(\rho_k) - nR\rho_k^2. \quad (8)$$

The first order condition gives:

$$\rho_k = \frac{p_{1,k} - m}{4Rn}. \quad (9)$$

In period one the expected profit of a generator is:

$$\pi_i = \left[ \frac{2D - (2n - 1)q_j - q_i}{2b} (1 - \rho_k) + \rho_k m \right] q_i, \quad (10)$$

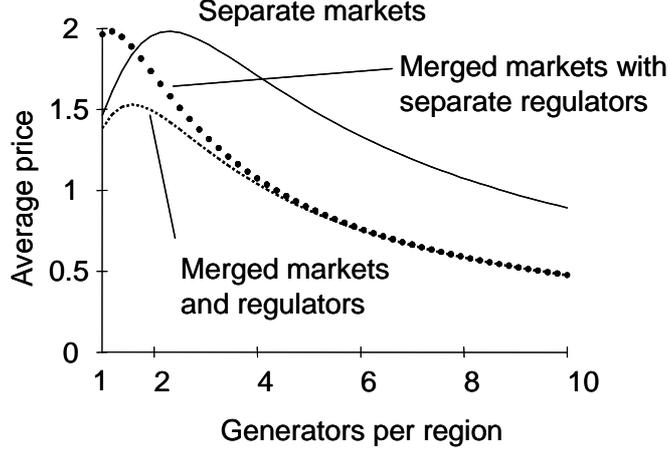


Figure 6: Parameter values  $D=10$ ,  $m=1$ ,  $R=2$ ,  $m=0.5$ .

and using the first order condition shows that the profit maximising output choice is:

$$q = \frac{(2n+1)(F-2Rbn) + \sqrt{(2n+1)^2(F-2Rbn)^2 + 4(n+n^2)(4RbnD-F^2)}}{2n(n+1)}.$$

In this example the output choice and price after the market integration is the same as that of a single market with twice the demand and number of players but only one regulator, a result of the specific assumption that monitoring/enforcement costs increase with the square of the intended success rate.

However, as we continue to assume two regulators, the monitoring effort of each is lower. Comparing (4) and (9) shows the level of monitoring/enforcement is only half that observed in the case with an integrated regulator.

Figure 6 shows first the prices in two separate regions (thin line). If the regulators retain their separate authorities after integration of the market, then the impact on neighbouring customers is not internalised and the prices can be higher (dotted line). If the regulators are merged, then we can again use results from the single market, but have to perform the following substitutions to represent the bigger market  $n \rightarrow 2n$ ,  $D \rightarrow 2D$ ,  $b \rightarrow 2b$  and finally  $R \rightarrow R/2$  as the monitoring/enforcement costs stay constant but the customer base is doubled so that the costs per customer is reduced (heavy dotted line). Integration of regions with the simultaneous integration of regulatory authority has the strongest impact on prices.

## 4 Evolution of market design

The European Commission is currently pressing the European Transmission System Operators to improve the management of transmission constraints between regions. There is some agreement

that from an efficiency (Neuhoff 2002) and market power mitigation perspective, Europe-wide nodal pricing or at least market splitting is to be preferred to other solutions (Ehrenmann e.a. 2003).<sup>4</sup> Both nodal pricing and market splitting can and should be complemented by long-term financial transmission contracts to allow for risk hedging and reduce market power through forward contracting (as currently implemented in PJM, Nordpool).<sup>5</sup>

However, it is difficult to envisage that all countries could be persuaded to move simultaneously to such a market design. It seems more likely that some regions will join up under a market splitting arrangement, following the example of Nordpool, and that remaining regions will then decide whether to follow. The model presented below demonstrates that such an evolution could be precluded if the alternative approach favoured by ETSO, of an Europe-wide synchronised auction for transmission capacity, is implemented.

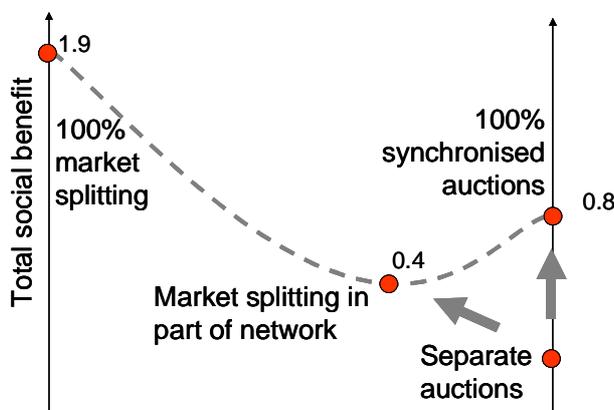


Figure 7: Total social benefit of different market designs with results from simulation.

Figure 7 illustrates, based on the numerical results derived in this section, the possibility that a move from current separate auctions to both synchronised auctions and market splitting in part of the network is likely to increase social welfare. Where congestion is low, the move towards market splitting in part of the network is preferable because it is better able to mitigate market power.<sup>6</sup> Where the network experiences significant congestion and volatile flow patterns, the initial move towards synchronised auctions is preferable to partial market splitting, because

<sup>4</sup>In theory a continuum of successive transmission markets might provide for the similar result. Such a design is difficult to implement and is unlikely to provide sufficient liquidity to allow for the redefinition of transmission contracts in meshed networks.

<sup>5</sup>The impact of physical or financial transmission contracts (Joskow and Tirole 2000 ) and their allocation (Gilbert e.a. 2003 ) on strategic behavior of generators can in first order be treated separately

<sup>6</sup>One could envisage that initially only the Benelux countries or accession countries use market splitting among themselves while continuing separate markets towards their neighbors (as already implemented between Nordpool and neighboring countries).

overall transmission capacity can be allocated to better match demand in different periods. In this latter case, a gradual move from synchronised auctions to market splitting may be difficult to encourage through a sequence of partial steps, as it could initially result in losses of efficiency. This suggests that a move towards synchronised auctions could result in a lock-in that makes a subsequent gradual evolution towards market splitting/nodal pricing difficult. The analysis also confirms that market splitting across the whole network provides the largest social benefit. Here, transmission capacity can be allocated at a later stages to deal with uncertainties. In addition the flexibility provided with both unconstrained and constrained transmission capacity reduces the exercise of market power by dominant generators. This might explain the preference of generation companies and vertical integrated TSOs for a synchronised auction.

We use the game depicted in Figure 8 to model the four different market designs: separate auctions, market spitting in part of the network, synchronised auctions and 100% market splitting. In the first period, separate auctions and market splitting in part of the network results in

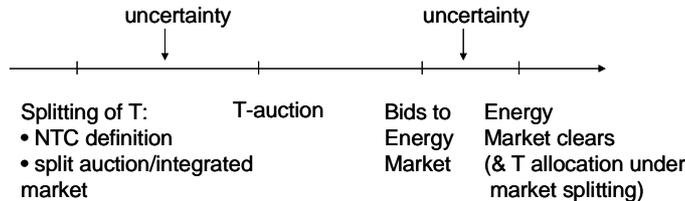


Figure 8: Timing of transmission allocation and energy markets.

an allocation of transmission capacity between different regions. The amount of capacity to be allocated corresponds to the current definition of Net Transfer Capacities (NTC) of ETSO. This allocation is typically performed on a yearly basis and so it is likely that some uncertainty  $\varepsilon_1$  will occur between the initial allocation and the day-ahead markets. In separated and synchronised auctions and also for part of the network that is not covered by market splitting, transmission capacity is auctioned on a day-ahead basis. Some of the information about generation availability, demand and the resource situation of renewable output will only be revealed in the energy markets, and so a second source of uncertainty  $\varepsilon_2$  will be revealed after the transmission auction. In the next period of the game, generators, demand, and possibly traders submit bids to the energy spot markets. In the final period, the energy spot markets will clear separately under the separate and synchronised auction designs, whilst with market-splitting the spot markets are cleared while simultaneously using transmission capacity between the regions to arbitrage the markets.

The model assumes a symmetric three node network presented in Figure (9). Price-responsive

demand is located at nodes  $A, C$  and competitive generation at node  $B$  with strategic generators at least at one node  $A$ . Uncertainty is concentrated at node  $C$ , where demand varies with

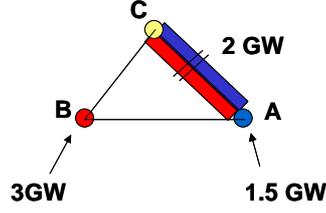


Figure 9: The network

the uncertainty  $\varepsilon_1, \varepsilon_2$ . For simplicity we assume that  $\varepsilon_i, i = 1, 2$ , is uniformly distributed on  $[-e_i, e_i]$ .

$$d_c = D_c + \varepsilon_1 + \varepsilon_2 - p_c. \quad (11)$$

At node  $B$  competitive generators offer output  $q_b$  at marginal cost, giving the following supply function

$$p_b = \beta_b q_b. \quad (12)$$

Finally, node  $A$  has local demand  $d_a$  and an oligopoly with  $n$  players each with output choice  $q_{a,i}$  and zero marginal costs:

$$d_a = D_a - p_a. \quad (13)$$

Nodes  $A$  and  $B$  export, and the potential constraint is on transmission line  $\overline{AC}$  with maximum transmission capacity  $K$ . According to Kirchhoff's law of physics,  $1/3$  of exports from node  $B$  and  $2/3$  of exports from node  $A$  will pass through link  $\overline{AC}$  on their way to node  $C$ . Hence the transmission constraint can be represented by:

$$\frac{1}{3}q_b + \frac{2}{3}\left(\sum_i q_{a,i} - d_a\right) \leq K. \quad (14)$$

Ignoring transmission losses in this simplified model, conservation of energy requires:

$$\sum_i q_{a,i} - d_a + q_b - d_c = 0. \quad (15)$$

The welfare measure for comparing the various outcomes counts consumer surplus and producer profits equally, so that total welfare equals the consumer utility from energy consumption minus generation cost:

$$W = d_a \left( D_a - \frac{d_a}{2} \right) + d_c \left( D_c + \varepsilon_1 + \varepsilon_2 - \frac{d_c}{2} \right) - \frac{1}{2} \beta_b q_b^2. \quad (16)$$

## 4.1 Integrated markets

We start by calculating the market equilibrium prices for the 100% market splitting case. If the transmission constraint is binding, then the transmission operator allocates transmission capacity on the scarce link  $\overline{AC}$  so that the marginal value of exports from  $B$  to  $C$  equals the twice the marginal value of exports from  $A$  to  $C$ , corresponding to the inverse of transmission capacity required for exports from both nodes:

$$p_c - p_a = 2(p_c - p_b). \quad (17)$$

The equilibrium price  $p_a$  will depend on whether or not the transmission constraint binds. If it does bind, then the relationship between  $p_a$  and the output choices of the strategic generators can be found from (13), (11), (12) and (17). Finally as the transmission constraint is assumed binding (14) and energy is conserved (15) gives the required relationship:

$$p_a = \frac{(1 + 4\beta_b) D_a - D_c - \varepsilon_1 - \varepsilon_2}{2 + 4\beta_b} - \frac{1 + 4\beta_b}{2 + 4\beta_b} \sum_i q_{a,i} + \frac{3}{2} K. \quad (18)$$

This can be used to determine the profit maximising output on the assumption that the constraint binds, which then needs to be checked. If the condition for a binding transmission constraint,  $p_a > p_c$ , is not satisfied, then the prices at all nodes will coincide. Using  $p_a = p_b = p_c$  instead of equation (14) and the relationship between nodal prices (17) gives a second equation for  $p_a$  as function of the strategic output choices:

$$p_a = \frac{D_a + D_c + \varepsilon_1 + \varepsilon_2 - \sum_i q_{a,i}}{2 + 1/\beta}. \quad (19)$$

If the transmission link were expected to be unconstrained, then the output choice that maximises expected profit  $\pi = q_{a,i} E[p_a | \varepsilon_1]$  is:

$$q_{a,i} = \frac{D_a + D_c + \varepsilon_1}{n + 1}. \quad (20)$$

However, whether or not the constraint is expected to be binding depends on the random factor  $\varepsilon_1$ . The Cournot output choice is found by a numerical search over possible maxima for different constraint configurations. The output  $q_{a,i}$  that maximises the profit of individual generators  $\pi = q_{a,i} E[p_a | \varepsilon_1]$ , depends on whether  $p_a$  is given by (18) or (19).

## 4.2 Separate auctions

The next case to consider is that transmission for exports from  $A$  and  $C$  is allocated in separate auctions, as is currently the case on different European interconnectors. The system operator has to determine how to split the capacity on the constrained link  $\overline{AC}$  for exports from  $A$  and

$B$  in the first period. This corresponds roughly to the definition of net transfer capacities of ETSO, but is sometimes refined to take account of local dispatch plans. Thus the definition of available transmission capacity between Germany and Netherlands is updated based on expected flows within both countries. We assume that the criteria on which capacity is allocated ensures that both transmission lines will stay unconstrained for the same set of  $\varepsilon_1$ . Let  $E_a, E_b$  be the export capacities made available in period 1 for exports from nodes  $A$  and  $B$  and  $F_a, F_b$  be the export capacity that traders obtain in period 2. Since no additional information is revealed subsequently,  $F_a, F_b$  will also schedule transmission to node  $C$  in period four. Given trade of  $F_i$  between the nodes, the equilibrium price at each node will be  $p_a$  is the Cournot output choice with  $n$  players:

$$p_a = \frac{D_a + F_a}{n + 1}, \quad p_b = \beta F_b, \quad p_c = D_c + \varepsilon_1 + \varepsilon_2 - F_a - F_b. \quad (21)$$

If the transmission remains unconstrained, then traders will arbitrage the prices  $p_a = p_b = E[p_c|\varepsilon_1]$ . Using (21), transmission demand will be:

$$F_a = \frac{(D_c + \varepsilon_1)(n + 1)\beta - D_a(1 + \beta)}{(1 + \beta + (n + 1)\beta)}, \quad F_b = \frac{D_a + F_a}{\beta(n + 1)}. \quad (22)$$

In order to determine the transmission allocation by the transmission operator such that transmission constraints for export from  $A$  and  $B$  start to bind simultaneously we substitute  $F_a = E_a, F_b = E_b$  in (22) and require that

$$2E_a + E_b = 3K, \quad (23)$$

to obtain the marginal realisation of uncertainty  $\varepsilon_1$  at which both constraints start to bind:

$$\varepsilon_1 = \frac{(1 + 2\beta)D_a + (1 + 2\beta + n\beta)3K}{1 + 2\beta + 2n\beta} - D_c. \quad (24)$$

Substituting  $E_b = F_b$  from (22) in (23) and substituting  $\varepsilon_1$  from (24) gives the equilibrium allocations by the system operator:

$$E_a = \frac{\left(\frac{(1+2\beta+n\beta)3K+(2\beta+1)D_a}{1+2\beta+2n\beta}\right)\beta(n+1) - (1+\beta)D_a}{1+2\beta+n\beta}, \quad (25)$$

and

$$E_b = \frac{\frac{(1+2\beta+n\beta)3K+(2\beta+1)D_a}{1+2\beta+2n\beta} + D_a}{1+2\beta+n\beta}. \quad (26)$$

Now it is simple to calculate the amounts of transmission rights obtained by traders to arbitrage the markets. If  $\varepsilon_1$  exceeds the value determined in (24) then transmission will be constrained and  $F_a = E_a, F_b = E_b$ . Otherwise traders will arbitrage prices and use transmission capacity according to (22).

### 4.3 Joint auctions:

The difference between the joint auction and the separate auction approach is that with joint auctions the allocation between  $F_a$  and  $F_b$  is no longer determined at the very beginning, but only in the transmission auction which takes place after  $\varepsilon_1$  is revealed.

For  $\varepsilon_1$  smaller than the critical value determined in (24) all transmission requests can be satisfied and the amount of utilised transmission rights is determined according to (22). The allocation differs from the separate auction if the transmission constraint is binding. Competitive traders bid for transmission capacity the expected value of using the transmission capacity - which follows from the equation for nodal pricing (17):

$$2E[p_b] = E[p_a] + E[p_c].$$

Considering the binding transmission constraint  $2F_a + F_b = 3K$  and substituting  $E[p_i]$  from (21) gives:

$$F_a = \frac{(2\beta + 1)3K - D_c - \varepsilon_1 - \frac{D_a}{n+1}}{2(2\beta + 1) - \frac{n}{n+1}}, \quad F_b = 3K - 2F_a.$$

### 4.4 Finally, a mix

In period one transmission capacity is allocated to be either used for exports from  $B$  to  $C$ ,  $E_b$ , or to be used in the integrated market between  $A$  and  $C$ ,  $E_a$ .

If all links are permanently unconstrained then the market-clearing price faced by strategic generators is given by (19). However, the output at node  $B$  will not change in reaction to output changes by the strategic generators, but only in anticipation of such output changes. As a result, only demand at  $A$  and  $C$  and not output at  $B$  will adapt and  $\frac{\partial p_a}{\partial q_{a,i}} = -\frac{1}{2}$ . If, however, the transmission constraint is binding, then the assumption of permanently unconstrained transmission is not satisfied. The strategic generators at node  $A$  will then maximise expected profits taking into consideration that both export constraints from  $A$  and/or  $B$  can be binding. In the numerical simulation competitive traders determine the amount of transmission rights  $E_b$  they use for exports from  $B$  such that either prices are arbitrated in expectation or all rights are used. Strategic generators make the output choice that maximises their expected profit given the output choices of competitors.

### 4.5 Results

We initially assume that  $\varepsilon_2 = 0$  and hence the only source of uncertainty is realised before the bids are submitted to the transmission auction and energy spot markets.

Figure 10 shows that welfare is maximised with an integrated energy and transmission auction, a result that will be replicated in subsequent simulations. It can be noted that for a

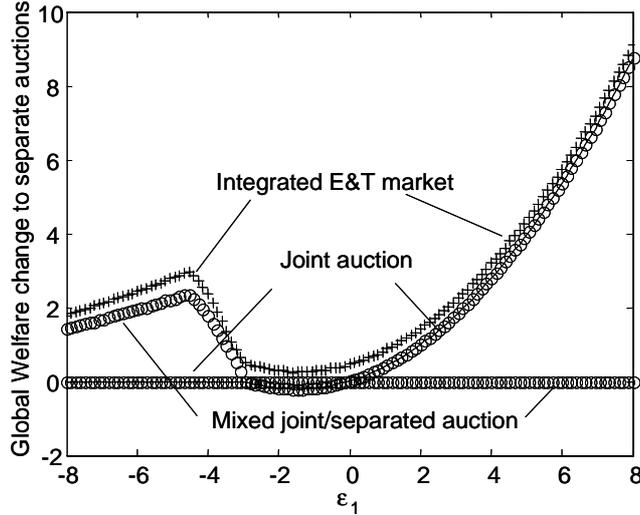


Figure 10: Welfare change:  $D_a = 10$ ,  $D_c = 10$ ,  $\beta = 1$ ,  $n = 7$ ,  $e_1 = 8$ ,  $e_2 = 0$ .

negative  $\varepsilon_1$ , which corresponds to low demand at node  $C$ , the export constraint from  $A$  to  $C$  is not binding and hence the partially integrated E&T market reduces (“mixed joint/separated auction”) the market power of generators at  $A$  and increases welfare. With the integrated market welfare is increased further, as generators at  $A$  are then also in direct competition with the generator at  $B$ . On the other hand, for large  $\varepsilon_1$ , and hence high demand at node  $C$ , the export constraint at node  $A$  is binding and the outcome and welfare of the partially integrated auction coincides with the separate auction. In these circumstances the joint auction is more beneficial, because scarce transmission capacity in the link  $\overline{AC}$  can be reallocated to allow more exports from  $B$ , which make more efficient use of the scarce resource.<sup>7</sup>

Figure 11 shows the same data as figure 10 except that the number of oligopolists is reduced from 7 to 3. It shows that higher concentration of generation at node  $A$  makes the market-power mitigating effect of integrating the energy and transmission markets more important, increasing the benefit of integrating the two markets. Comparing Figures 10 and 11 we note that where market power is weak and constraints frequently binding, the allocation of transmission capacity conditional on the realisation of  $\varepsilon_1$  as ensured by a joint auction will provide for greater improvements in welfare relative to a separate auction than a partially integrated energy and transmission market. Alternatively, with less frequently constrained markets, or with increasing market power (represented by lower  $n$ ) the market-power mitigating effect of a partially integrated

<sup>7</sup>For  $-2 < \varepsilon_1 < 0$  the separate auction results in higher welfare than a joint auction because of market power. In order to mitigate market power, it can be beneficial to allocate transmission capacity to maximise welfare, which, in the presence of market power, can diverge from the allocation assuming competitive behaviour. However, it would be very difficult to specify such policies.

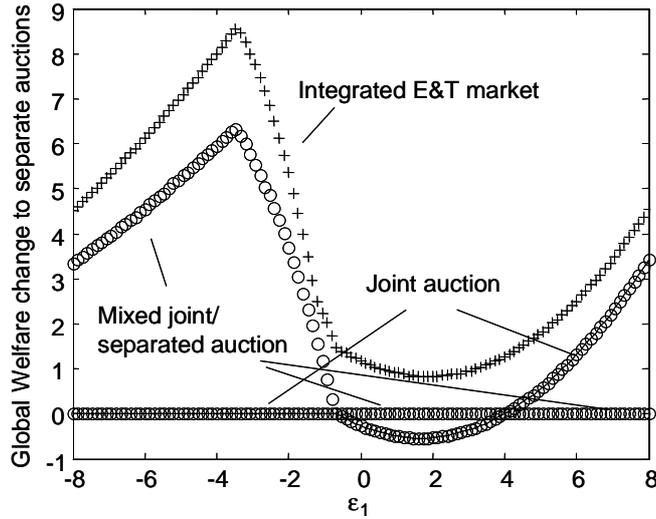


Figure 11: Welfare change:  $D_a = 10$ ,  $D_c = 10$ ,  $\beta = 1$ ,  $n = 3$ ,  $e_1 = 8$ ,  $e_2 = 0$ .

energy and transmission market dominates and provides for greater improvements in welfare relative to a separate energy and transmission market than a joint transmission auction.

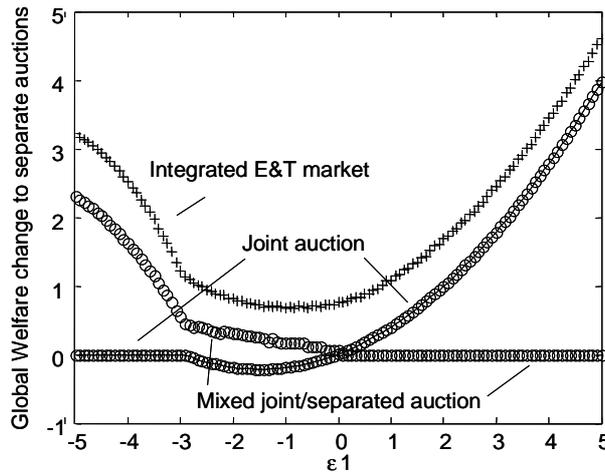


Figure 12: Expected welfare change:  $D_a = 10$ ,  $D_c = 10$ ,  $\beta = 1$ ,  $n = 7$ ,  $e_1 = 5$ ,  $e_2 = 3$ .

Figure 12 shows the effect of introducing uncertainty  $\varepsilon_2$  after the participants submit bids. This uncertainty corresponds to the information that is aggregated in the market only during the auction, and is therefore not available to Cournot players submitting their bids or to energy traders arbitraging the markets. The Figure depicts the expected welfare change based over the distribution of  $\varepsilon_2$ . Compared to Figure 10 we notice that the flexible allocation of transmission capacity provided by the integrated energy and transmission market increases the benefit result-

ing from the partially integrated energy and transmission market and particularly from the fully integrated energy and transmission market, both relative to the separate market and to the joint auction.

If  $\varepsilon_1$  and  $\varepsilon_2$  are uniformly distributed on  $[-5, 5]$  and  $[-3, 3]$  respectively, then the partially integrated auction increases welfare by 0.4 units relative to the separate auctions, the joint auctions improve the welfare by 0.8 units, and the integrated energy and transmission market increases the welfare by 1.9 units. This result shows that a move towards a joint auction could result in a lock-in. It is likely that a partially integrated market would be an intermediate step towards an integrated market, and therefore result in welfare losses of 0.4 units. Hence the joint auction might imply a lock-in at 1.1 units below the welfare maximum achievable with an integrated auction.

This result depends on the exact characteristics of the market. If market power is stronger ( $n = 3$ ) then even the move from the joint auction towards an partially integrated market design is welfare improving. The implication is that careful simulation of the various alternatives should be undertaken before choosing particular reforms, to check that they do not result in disadvantageous lock-ins.

## 5 Conclusions

The European Commission is concerned to create a single electricity market in the European Union, and to improve trade between regions currently under separate regulation and TSOs. Our first model suggests that the process of introducing competition within countries could initially lead to increased prices, although further deconcentration should be pro-competitive. The same effect can happen when integrating markets that were previously concentrated, with the additional complication that regulatory and monitoring effort may be reduced with market integration and could result in higher than expected prices. The problem can be addressed by suitable cooperation between regulators. Finally, the paper addresses the question whether the sequencing of changes to the management of interconnectors matters, and if so, whether the resulting path-dependence may foreclose desirable end-states. The very simple model shows that this is indeed a possibility, suggesting that in the more complex reality of the European transmission network, it will be important to simulate alternative sequencing of the integration of successive markets with a move to coordinated auctions.

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