Mitigating market power in electricity networks

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The paper concentrates on four aspects of mitigating market power in European electricity networks: capacity divestiture, entry, promoting interconnection, and the capacity to regulate competition in generation, drawing on lessons from Britain, California and the Continent. Each of these actions can improve the intensity of competition in electricity wholesale markets, but attractive strategies to promote any one of these may, unless carefully designed, be in conflict with other strategies, with possibly long-term disadvantages. Trading divestiture for the right to vertically integrate, or promoting contracts at the expense of a transparent spot and balancing market may increase short-run competition at the expense of entry. Gas liberalisation would greatly facilitate efficient electricity markets.

Introduction

The European electricity market is being liberalised primarily by pressure from the European Commission through the Electricity Directive 96/92/EC. The case for electricity liberalisation was based on the success of Britain and Norway in introducing competition into the wholesale electricity market, combined with the observation that electricity prices differed widely across the Continent. If customers were free to buy from cheaper suppliers, then wholesale and retail prices would fall in response to competition, and producers in different countries would have access to similarly priced electricity. This would fulfil the aims of the single market - "the free movement of goods, persons, services and capital," and hence increase European competitiveness.

The analysis was sound, but for electricity liberalisation to deliver sustainable and competitive prices, a number of important pre-conditions must be met. The first is that there is adequate and secure capacity relative to peak demand. Electricity cannot readily be stored (except as storage hydro), so reserves must be sufficient to meet generation outages, unexpected surges in demand, and, in a liberalised market, strategic bidding or capacity withholding as demand increases relative to available capacity. Second, for the wholesale market to be competitive, potential suppliers must have access to the transmission system in order to reach customers. This certainly requires legal unbundling of transmission from generation at the least, though ownership separation is preferable. This also applies to import capacity, and requires that customers have access to foreign suppliers and that incumbent generators do not

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control the import capacity. Third, there needs to be sufficiently many independent generators competing to supply each customer, and that in turn requires adequate transmission. Transmission constraints fragment the market, reducing the number of generators actively competing in sub-markets. Finally, markets for contracts, spot energy and ancillary services need to be sufficiently well developed, liquid, and competitive to enable the increased risks created by vertical unbundling to be adequately managed. The higher the share of electricity sold under contracts, the lower is the incentive to manipulate the spot price. For the contract market to be competitive, the number of generators offering contracts (with appropriate profiles) should be adequate, and the threat of entry by new Independent Power Producers (IPPs) should be credible. That in turn is facilitated by a liberalised gas market that allows IPPs to build efficient gas-fired plant.

The Italian Electricity Supply Industry (ESI) would seem to present a particularly interesting case study and challenge to these conditions. The industry is characterised by extremely tight reserve margins at the peak (a few hundred MW when peak demand is some 50 GW), a highly concentrated ownership structure, relatively high cost and inefficient oil-based generators setting the system marginal price, and limited import capacity (relative to demand). If liberalisation is to be successful in Italy, considerable care will have to be taken to address these limitations.

The old vertically integrated franchise monopoly structure that characterised European electricity markets for the most part is now under threat. The old structure had considerable attractions to incumbents, as it minimised risk, allowed them to finance investment from captive consumers, and to pass through fuel price shocks and other market disturbances. The new structure creates substantial risk in the wholesale market, for when wholesale prices are low, upstream generators make losses, while consumers and suppliers benefit, but if wholesale prices are high, generators profit at the expense of downstream customers. Supply liberalisation shortens contract lengths, as suppliers fear losing customers if subsequent wholesale prices fall. The short duration of contracts makes financing investment potentially risky and encourages vertical integration between generation and supply. The more competitive the wholesale market, the more difficult it is to recover the high fixed costs of generation, while tight electricity markets give generators with even a modest market share considerable influence over the spot price.

The natural response to this increased risk is for incumbents to vertically and horizontally integrate to better manage risk, deter entry, manage the capacity margin, and hence restore prices to profitable levels. Liberalisation in Europe has been associated with a somewhat half-hearted attempt to increase the number of generating companies in each country. Even where this was successful, mergers across borders have created a small number of European-wide powerful generating companies. In anticipation or response to this, other countries have attempted to protect national champions to ensure that their incumbent companies can survive to join the small number of remaining companies post-liberalisation. A single European electricity market with six or seven comparably sized generation companies might not raise competition concerns if there were adequate transmission capacity across the continent. This is far from the case, as existing interconnection was primarily designed for improved reliability within a structure that aimed at national self-reliance. Despite the substantial variation in wholesale prices across the Union, wholesale trade is only eight percent of all electricity generated in the European Union. The competitiveness of cross-border trade is further compromised when some generation companies (particularly in Germany) own half of the interconnection. Further, some generation companies on one side of the border have bought generation and supply companies on the other side of the border, while legacy long-term interconnection contracts further restrict access by other suppliers.

Wholesale markets are gradually emerging at various market hubs, but they still account for only a modest fraction of trade, most of which is conducted through the OTC market or within vertically integrated utilities.

Finally, electricity regulation is a relative recent concept, regulatory agencies are still often under-staffed, and lack adequate powers to collect information and monitor the wholesale electricity market. The lack of any guidance in the Electricity Directive on market surveillance, and the assumption that ordinary competition law may be adequate to deal with potentially competitive markets, further raises the risk of abusive market behaviour by generators falling below the dominance threshold of 40%.

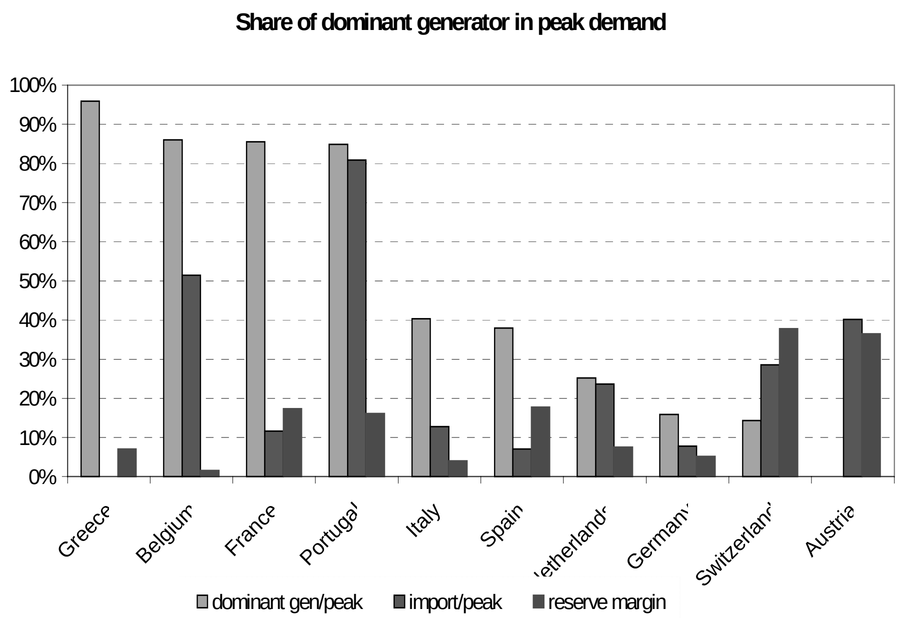

Fig 1 Market power of dominant generator

The reluctance to fragment the once powerful incumbent electricity utilities and make them vulnerable to foreign takeover means that the dominant generator still has an unacceptably high fraction of the relevant market in most EU countries. Figure 1 gives the share of the dominant generator in peak demand, assuming that all other generators supply up to their assumed available capacity (85% of nominal capacity). The same figure also shows the ratio of import capacity to peak demand and the reserve margin over and above that needed for system stability. Figure 2 shows the ratio of the available generation capacity of the largest company to the reserve margin added to the import capacity. Where this is greater than 100% (as it is for almost all countries for which ETSO data are available) the implication is that the dominant generator is needed to meet demand without precipitating a power cut, and therefore has potentially unlimited market power to set prices, certainly at the peak. A more refined analysis would use the load-duration curve to determine the fraction of the time that the dominant producer is a residual monopolist.

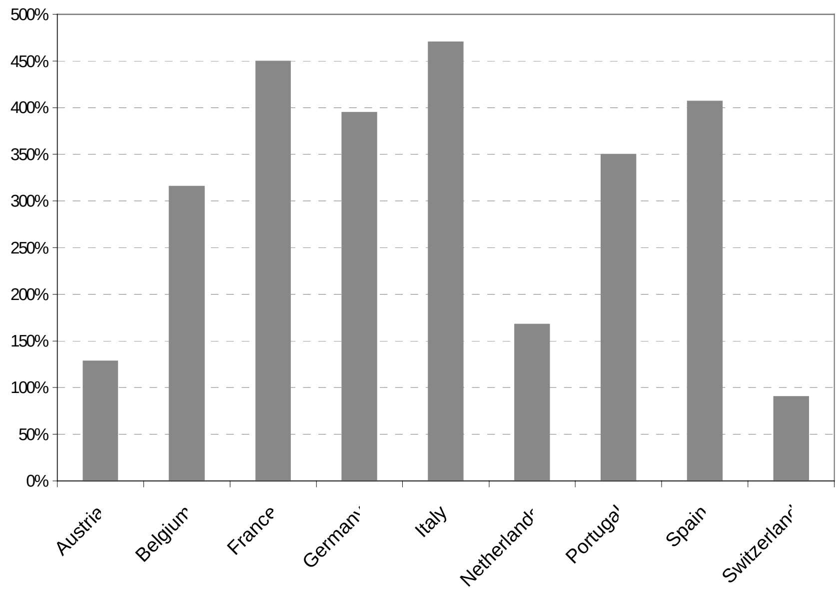

Figure 2 Ratio of dominant generator to reserves plus imports

In the Electricity Directive, the European Commission was primarily aiming to create a single electricity market, and to remove the impediments to customer choice of supply and cross-border trade. The implicit assumption was that this would be sufficient to create competitive markets, or at least if not, then addressing market power could be left to the regulators or competition authorities in individual countries. The Commission evidently saw no need (or lacked the jurisdiction) to ensure that the resulting market structures were sufficiently competitive before accepting liberalisation.

In the United States, the Federal Electricity Regulatory Commission, FERC, has a statutory obligation under the Federal Power Act 1935 to ensure that individual State Regulatory Commissions manage liberalisation to ensure that wholesale prices remain “just and reasonable”. If an electric utility wishes to sell at market-determined wholesale prices, this will be only allowed providing “the seller (and each of its affiliates) does not have, or has adequately mitigated, market power in generation and transmission and cannot erect other barriers to entry.”[1] Even then, the authority to sell at market-determined prices can be withdrawn and replaced by regulated prices if there is “any change in status that would reflect a departure from the characteristics the Commission has relied upon in approving market-based pricing.”[2] Liberalising the

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[1] *Heartland Energy Services, Inc*, 68 FERC ¶ 61,223, at 62,060 (1994), cited by Bogorad and Penn (2001).

[2] *Heartland* 68 FERC at 62,066, cited as above.

wholesale market therefore requires that incumbent utilities reduce their market power. Normally this is done first by negotiating first the separation of transmission from generation, and then selling sufficient capacity to reduce the incumbent utility's market share to an acceptable level. Consumers (and Public Utility Commissioners) believed that competitive wholesale markets would deliver prices reflecting the future and lower costs of high efficiency combined cycle gas turbine (CCGT) generation (or the avoidable cost of existing thermal and nuclear plant), rather than the average cost of expensive past investments. Utilities were only willing to accept market reform if they could recover stranded costs from past, regulated investments. With luck, new CCGT technology and low gas prices would allow all parties to gain. The Californian crisis was a salutary reminder of the difficulty of delivering competitive low prices even when market players appeared to have only modest market shares. It is illuminating precisely because it took place within an apparently favourable institutional and policy framework.

The lessons from California

California originally reformed and liberalised its electricity market because of dissatisfaction over high consumer prices. However, average wholesale prices in 2000 were more than three times those of 1999, while December 2000 prices were 10 times as high as normal, even though California is a summer-peaking system. 2001 started with rolling blackouts, stage 3 alerts,[3] and the major public utility, PG&E, filing for Chapter 11 bankruptcy protection. California shows that poor market design, coupled with inappropriate regulatory and political intervention, can rapidly produce extremely unsatisfactory outcomes when capacity is tight, particularly if the shortages are unexpected. It also shows the danger of relying on significant imports to meet peak demand without ensuring supply adequacy elsewhere in the interconnected system.

The reasons for this supply inadequacy were long-standing but concealed by the apparent abundance of cheap surplus hydroelectric power that could be imported from the Columbia River. Under-investment in generation in California derives partly from disputes over nuclear power plant costs and safety, partly from environmental objections, and partly because misconceived long-term Power Purchase Agreements (PPAs) with Qualifying Facilities, QFs, typically owned by "non-utility generators", were considerably more expensive than imported power.

The reason that supply inadequacy lead to bankruptcy and major disruption were peculiar to the legacy of these high-priced PPAs. As a result, the California Public Utilities Commission was reluctant to allow the recently unbundled distribution companies to sign long-term contracts for electricity or hedging for fear that they would replicate the earlier stranded QF contracts. That in itself might not have caused bankruptcy, but the CPUC also capped the final retail price (until sufficient revenue had been collected to pay off the assets stranded by the unbundling of high cost generation).[4]

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[3] when reserve margins fall below 1.5% so that disconnection is essential to protect system integrity

[4] In addition, the utilities considered that the contract prices offered were unacceptably expensive, compared to past experience, and were thus unenthusiastic about hedging. In the event the contract prices would have been extremely cheap compared to the subsequent spot prices.

Finally, NO_x emissions were capped by region (and in some cases by plant) on an annual basis. In the (not particularly) hot summer of 2000, gas demand for generation greatly increased, and pipeline capacity and storage were frequently inadequate to meet the demand. Californian gas spot prices more than doubled (coming on top of high prices caused by the doubling of crude oil prices), as did the contract prices from many QFs, which were indexed to gas prices.[5] The price of tradable NO_x permits also rose to unprecedented levels as the annual quota became inadequate, with permits trading at $80,000/ton at their peak, compared with $400/ton on the East Coast (Laurie, 2001). Electricity prices rose, not just in California, but in the whole western interconnection in which wholesale power is traded. Thus the average price for the *whole year* at the Mid-Columbia hub in the Northwest (i.e. not in California) was $137/MWh compared with $27/MWh in 1999, higher than in California (where it averaged $91/MWh on the Power Exchange). California's largest distribution companies were unable to pass on the high wholesale prices, precipitating a financial shortfall as revenue fell far short of cost.

High plant utilization in the summer and autumn induced by high spot prices necessitated greater scheduled maintenance downtime in the normally quieter winter period. Unfortunately, the combination of a dry winter in the Columbia River Basin lowering hydro output potential, with higher demand due to the colder weather, and plant outages in California, caused a severe shortage of capacity and energy, leading to higher prices, defaults, and bankruptcy. Inept price caps caused generators to export to neighbouring states, rather than sell in California, while the non-utility generators refused to supply for fear of not being paid. The repeated interventions of the State Governor arguably made a bad situation far worse; as threatened seizures, price caps, and regulatory hurdles prejudiced investment in generation and led to panic long-term contracting at high prices. Poorly designed trading arrangements, with caps on some markets that encouraged participants to under-contract in the day-ahead market and diverted power to the real-time market at very high prices, amplified market power (Wolak and Nordhaus, 2000).[6]

Joskow and Kahn (2002) have carefully documented the causes of the summer price rises in 2000 (which averaged five times those of 1998-9) and demonstrated that market power exercised in tight markets was responsible, although high gas and NO_x prices would have caused half the increase even in a competitive market. This was before the more serious problems of bankruptcy, inept intervention and outages started in December 2000, and hence a better test of the potential for exercising market power in tight but otherwise normal market conditions.

Clearly, the Californian electricity crisis has awakened fears that liberalised electricity markets may be politically unsustainable, at least, without careful design and regulation. The very high prices observed in California (and in the North- and Mid-West

[5] By the end of 2000 gas prices had risen to $15/MMBtu compared to a historic average of $2/MMBTu, and December electricity prices were estimated to be three times higher as a result. On one occasion after an accident disrupting deliveries on one of the major pipelines, spot gas reached $61/MMBTU, equivalent to an fuel cost in a reasonably efficient generator of $610/MWh (Bogorad and Penn, 2001).

[6] Evidence about manipulative trading tactics by Enron has subsequently emerged (*New York Times*, May 9, 2002).

of the United States) have demonstrated very clearly that uncontracted generators can exercise considerable market power when supply is tight. Defenders of the former electricity industry structure have argued that vertically integrated franchise monopolies with regulated final prices are the only way to secure adequate capacity to avoid shortages and/or high prices (see, e.g. the pseudonymous Price C Watts, 2001).

Electricity price determination in theory and practice

The electricity wholesale market has a number of distinctive features that profoundly influence price formation. Electricity cannot be stored,[7] supply must be instantaneously matched to demand, transmission constraints require active systems balancing, and demand is highly inelastic in the short run over which daily price variations occur. As a consequence, electricity markets are managed by system operators (SOs) who need short-run direct control over at least some plant, creating important differences with other commodity markets, even gas. The most obvious evidence of these distinctive characteristics is the considerable volatility over short time periods. The English pool price has moved from £11/MWh to £1,100/MWh over a single 24-hour period, and even more extreme price spikes have been seen around the world.

Modelling price formation to understand market power and market efficiency is both challenging and important if regulation and market interventions are to be intelligently applied. Green and Newbery (1992) modelled the English Electricity Pool by adapting Klemperer and Meyer's (1989) supply function equilibrium (SFE) model. This approach is both natural and empirically supported for a single-price gross pool with a daily bidding round - as in the English Pool. The model is challenging to solve and typically gives a continuum of equilibrium prices.

Auction models have been proposed, and are useful for comparing single price and pay-bid trading arrangements, but are even less tractable.[8] Standard Cournot oligopoly models are simpler, can be defended in tight market conditions, but suggest a more deterministic outcome than supply function models with their range of indeterminacy. Increasingly, consulting companies are developing price-formation models, the best of which capture the strategic aspects of supply function models with more careful modelling of the non-convexities of start-up costs which can dramatically influence the cost of providing additional power for short periods.

Despite this apparent diversity of approach, theory and evidence suggest considerable agreement about the nature of the resulting equilibrium. Competition is more intense (closer to Bertrand) and prices closer to avoidable costs with spare available capacity, but as the margin of available capacity decreases, competition becomes less intense and outcomes closer to Cournot (as in the SFE). Contracts lock in prices and reduce the influence of spot prices on generator revenue, making the relevant market size that for uncontracted output. The dominant short-run strategy for a fully

[7] Except as water in dams in hydro systems, but the ability to withhold water in low demand periods for release at high demand periods is very limited except in a small number of countries. Even when a significant fraction of capacity is hydro (as in California) it is typically capacity constrained at the peak.

[8] e.g. von der Fehr and Harbord (1993), or Green and McDaniel (1999)

contracted generator is to bid short-run avoidable cost (Newbery, 1995). The threat of entry by competitive generators limits the average price that can be sustained and encourages incumbents to contract and bid to maximise profits without inducing excess entry. Peak prices depend on the relation between maximum demand and maximum available capacity. The returns to peaking plant depend on the prices reached and the number of hours for which they are paid. Inelastic demand[9] means that in tight markets even apparently unconcentrated generation (e.g. with Herfindahl-Hirshman indices below 1800), can sustain extremely high price-cost margins for short periods. The considerable degree of discretion in choosing price strategies even without tacit or other collusion may make the threat of regulatory intervention effective,[10] while repeated interaction on a daily basis can certainly encourage tacit collusion (and was the main argument for replacing the Pool by the New Electricity Trading Arrangements).

Green and Newbery (1992) argued that the restructuring of the CEGB into two price-setting generating companies gave too much market power to the incumbents, and, on the basis of a demand elasticity of 0.2,[11] argued that dividing the generation capacity among five equal size firms would considerably improve competition. This conclusion, which appeared to be influential in restructuring the Victoria electricity market in Australia, seemed to be borne out by the evidence of significant price falls there, compared to apparently excessive price-cost margins in England. We were arguably too sanguine about demand elasticities, and lower but quite plausible values would confer considerable market power even with five or more generators, at least, as capacity shortages emerge. Halving the elasticity of demand (at some reference price, quantity pair) would double the peak price-cost margin reached, *cet. par.*[12] Later work by Newbery (1998a) argued that the conditions of entry and the extent of contract coverage were both critical in determining the average price level and its volatility, so that other things would not remain constant if demand elasticities changed. Analyzing market power therefore has to pay attention not just to concentration and demand conditions (both of which may be significantly affected by inter-regional trade), but also to entry and contracting conditions, which tend to be overlooked in most discussions.

If incumbents do not need to worry much about entry or regulatory intervention, then the logical strategy for companies in a competitive ESI would be to merge to increase market power, and close plant to tighten the margin of spare capacity. Making contracts unattractive to exploit consumer risk aversion increases the size of the residual market. All these actions increase market power and hence allow non-collusive price

[9]The majority of electricity is sold at fixed prices based on the average spot price, and hence very insensitive to peak prices. Even if consumers could adjust demand in response to these spot prices, most have no incentive to so respond. Nevertheless, demand responses are not zero - almost 30% of California's consumers cut demand by more than 20% to qualify for a 20% price rebate, while temperature-corrected demand fell 12.4% from June 2000 to June 2001, with peak demand down 14.1%. (*Financial Times*, Aug 21, 2001).

[10] Important in the English Pool, and certainly credible given the power to refer generators to the competition authorities.

[11] at the competitive price, higher at the monopoly price given assumed linear demand schedules.

[12] Holding constant contract coverage and the number of firms

bidding to reach high prices. Incumbents owning transmission can deter entry by capturing all capacity rents to generation and transmission in access charges to the grid. That appears to be the game being played out in Germany, where the incumbents are vertically integrated, subject only to negotiated third party access, and with no specialist regulator to oversee their behaviour (Brunekreeft, 2002).

If entry is relatively low risk, and there is adequate capacity within the industry, then incumbents benefit from credibly committing themselves to bid so that the average price remains below the entry-inducing price, as explained below. The entry price will be typically above the avoided cost of existing generation, and the cost of inducing entry is foregoing the difference between the entry price and the avoidable cost of some existing displaced capacity. Newbery (1998a) showed that in such cases the annual average price would be relatively insensitive to the number of competitive incumbents, but the volatility of such prices would be lower the more competitive the industry, provided the entry price remained unchanged with increasing competition and demand forecasts were accurate.

Strategies for mitigating market power

The British experience is instructive in demonstrating the importance of market power in determining prices. Figure 3 shows the evolution of output shares in England and Wales during the period of the former Electricity Pool,[13] starting with the two fossil-fuel generators setting the prices between them as a duopoly. The regulator and subsequently the Department of Trade and Industry encouraged the duopolists to divest price-setting plant, while the high prices encouraged massive investment in new gas-fired CCGT, over half of which was by Independent Power Producers (IPPs).

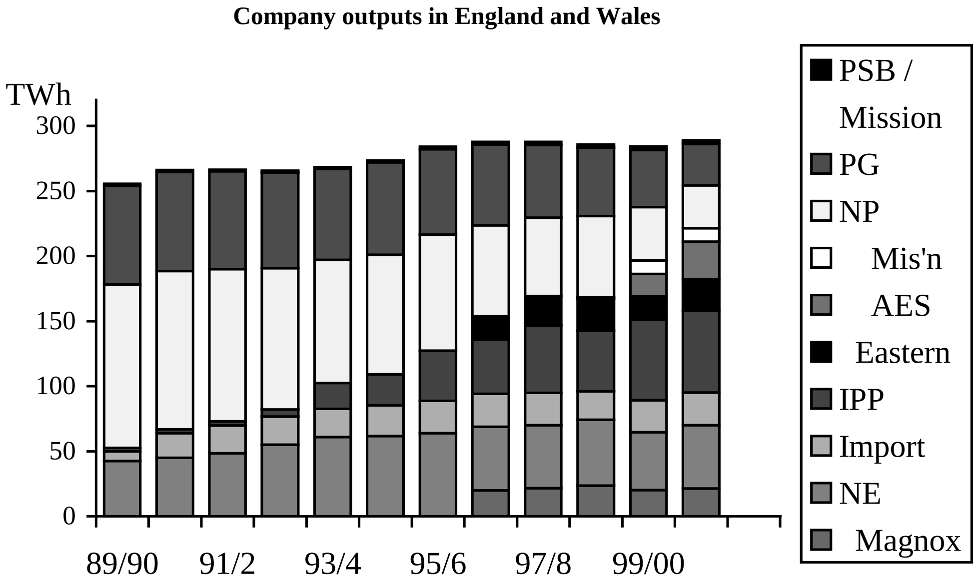

Figure 3 Deconcentrating Generation

[13] With the end of the Pool in 2001, the monthly statistical reports of company outputs ended, but since then further divestment has made the market even less concentrated, so that by March 2002 over 7 companies owned comparable shares of price-setting coal-fired capacity.

The contrast with Scotland is instructive, for there the two vertically integrated incumbents were not restructured. Scotland had a structural surplus of generation that was exported to England over interconnectors owned by the Scottish companies, thus preventing access to the Scottish market by English companies. The results can readily be seen in the consumer prices in the two capital cities. Figure 4 shows that while domestic prices in Scotland were originally some 10% cheaper than in England, by 2001 the reverse was true. Competition south of the border drove down prices, but lack of competition north of the border failed to pass through the various cost reductions. The effect of post-2001 fragmentation of generation has resulted in even more dramatic falls in English wholesale prices, though these have not yet been fully passed through to domestic consumers.

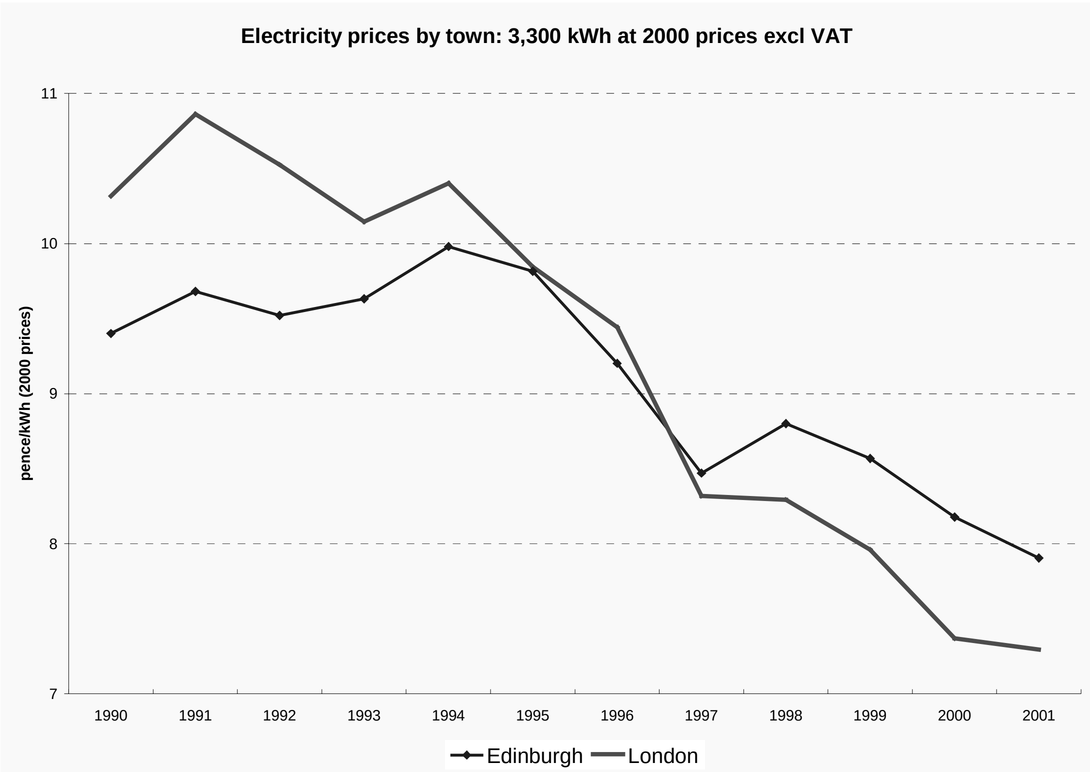

Figure 4 Domestic pre-tax prices in Edinburgh, Scotland and London, England

The first lesson to draw from the British experience is that the generation assets should be divided among a sufficiently large number of competing companies, preferably before liberalisation, and that ownership of generation should be separated from transmission. If that is not done initially, then the competition or regulatory authorities need to provide strong incentives to encourage subsequent divestment, as in England. The bargaining counter in the United States has been the ability to sell at market-determined rates, in exchange for which regulated utilities have unbundled and divested plant. In Britain the deal was initially to end a price-cap and avoid a reference to the Monopolies and Mergers Commission (MMC), and subsequently to allow generators the right to vertically integrate with supply (retailers). Some of the original incumbents also found buyers willing to pay prices that were higher than the predicted present value of a station's profits in a market that the incumbents correctly anticipated to become more competitive.

Finding an effective lever to encourage Continental generators to divest capacity may not be so simple, but is certainly worth pursuing. One strategy that the Commission has tried is to allow cross-border mergers only if concentration within domestic markets is reduced. Whether or not that reduces market power will depend on the way the relevant markets interact, and here market simulation models can be helpful (Day and Bunn, 2001).

Entry

Truly competitive markets for electricity are probably either not attainable or not sustainable. Electricity cannot readily be stored, so unused capacity has potentially a very low spot value in a competitive market.[14] The competitive price will be the short-run marginal cost of the most expensive plant required at any moment to meet demand. In order to have adequate reserves to meet demand at the peak with high probability the reserve margin for much of the time will be sufficiently high that the marginal plant is likely to be reasonably efficient. In mature systems with sufficient capacity, the average system marginal cost is typically only about half the average cost of generation.[15] In order to cover the fixed costs and make it worthwhile retaining marginal plant to supply reserves, prices will either have to be very high some fraction of the time, or these fixed costs will have to be paid by some form of capacity payment. High spot prices in competitive (as opposed to oligopolistic) markets require tight markets and low reserve margins, and increase the risk of (very costly and disruptive) losses of load. A small error in forecasting future demand when deciding on investment in generation capacity could mean either that future spot prices are unprofitably low (slightly too much capacity) or very high (slightly too little) with the consequent risks of system failure, not to mention political or regulatory intervention.

Investing in competitive electricity markets is therefore very risky. More generally, liberalising the electricity market creates market risks at the wholesale level where previously there were none in a vertically integrated industry. Low wholesale prices shift benefits to consumers at the expense of generator profits and vice versa. The logical response to this new risk is to create hedging instruments that once again share the risk efficiently between upstream generators and downstream consumers (or

[14] Electricity can be stored as water behind dams, but there is only a relatively small fraction of such capacity available (unconstrained by transmission capacity) to the main European demand centres. It may also be economic to store energy in fuel-cell form, though the cost is still high. Unused capacity has an option value measured by the Loss of Load Probability, but this is an essentially exponential function of the reserve margin (Newbery, 1995) and hence very low except when demand is tight.

[15] If past investment has been low, so that there is still a large amount of old plant supplying mid-merit demand, the variable cost of the highest cost plant required for much of the year may be high compared to the average cost of new plant. That was the case in the first few years after privatization in England before the entry of some 25% of existing capacity of CCGT. Without careful market design, it will be commercially unattractive to keep such plant on the system, so the range of plant variable costs will be compressed, and the ratio of system

suppliers acting on their behalf). Most commodity markets evolve a range of physical and financial contracts, including very liquid futures contracts, to hedge spot market volatility.

Most commodities traded on such markets are homogenous, storable, and can be moved cheaply between markets, facilitating the emergence of standard and liquid contracts. Electricity appears to be homogenous (all electrons are identical) but because it cannot be stored its value can change dramatically from moment to moment. Electricity in successive trading sessions (half-hourly in Britain) is thus a different product. Contracts are therefore more bespoke, have higher transaction costs, and there are only limited possibilities for standardisation (base-load power is the best example, or constant amounts for groups of adjacent week-day hours). The resulting contract markets are either very short-term (day-ahead), or limited to a few standard contracts, and/or very illiquid. Whereas actively traded futures markets for other commodities may have trading volumes many times final delivery (10-20 times in some cases), trade in standardised electricity contracts is normally far less.

Decentralised competitive electricity markets thus face considerable obstacles if they are to handle risk and hence encourage investment. The capital markets are clear as to the solution. Concentration and market power offers the smaller number of competing generators the prospect of greater control over prices. This allows them to keep prices above variable cost and hence recover their fixed costs. More important, the ability to control prices reduces investment risk as future prices should be more controllable and hence more predictable. An uncontested monopolist has no problem deciding on investment, though it is more difficult in an oligopoly. They may be able to tacitly co-ordinate on future expansion (e.g. by taking turns to make expansion investments), and the threat of potential entry may persuade them to undertake possibly slightly premature investment to keep prices from attracting too much entry. It is possible to imagine a quasi-stable industrial structure that delivers enough investment to ensure supply adequacy at prices above, but not excessively above, the long-run marginal cost.

Once more the British example is useful to demonstrate the importance of entry. Initially, electricity prices were set by coal-fired generators that held 80% of capacity and burned high-cost domestic coal. At these prices, entry by efficient CCGT was marginal, but attractive under certain conditions, which were satisfied. Specifically, the Regional Electricity Companies (or RECs, i.e. the distribution companies) were allowed to sign long-term Power Purchase Agreements (PPAs) with IPPs provided they could demonstrate that the terms were economic. Given uncertainties about emissions controls, fuel prices, and the heavy dependence of generators on a single fuel, coal, this was relatively simple. There was explicitly no prohibition on the RECs having equity participation in the IPPs with whom they contracted, in order to encourage entry to redress the excessive levels of concentration. In the U.S., such “sweetheart” deals would probably have been declared illegal, and considered anti-competitive, though in Britain the intention was pro-competitive. Potentially anti-competitive aspects were further safeguarded by the

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marginal cost to average cost will fall.

plan to end the franchise in 1998 and with it the need to regulate contracts for domestic customers.

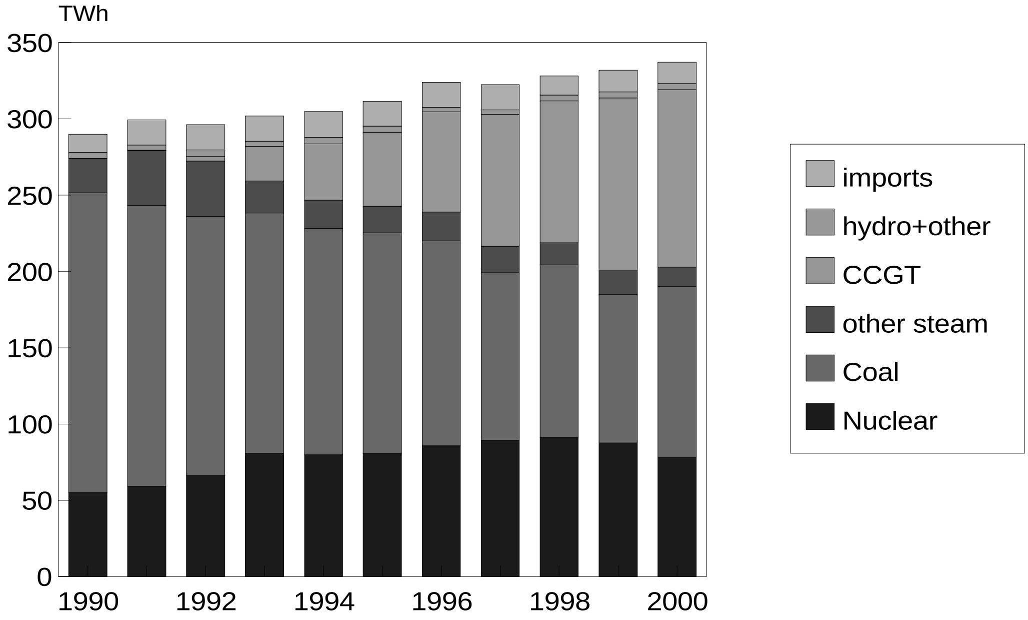

Figure 5 Generation in England and Wales by Fuel Type

The resulting "dash-for-gas" saw massive entry to the point that generation from gas was eventually contributing an equal share with that from coal (Figure 5). The reason why the threat of entry was both credible and occurred was that potential entrants could sign 15-year PPAs with the RECs at fixed prices and then sign 15-year gas contracts with British Gas also at fixed prices. With this assured cash flow, they could borrow money from banks, and buy turnkey CCGTs with performance guarantees, thus shedding almost all risk, allowing high gearing and only 20% equity. Once entry is contestable, incumbents risk losing market share for up to 15 years, and can offer contracts at entry-deterring prices to forestall entry.[16] Thus the combination of a domestic franchise with an incentive to sign PPAs made the wholesale market contestable. Arguably the compulsory single-price Electricity Pool acting as the electricity wholesale market further facilitated entry. One of the reasons given for ending the Pool and replacing it with the New Electricity Trading Arrangements (NETA) was that IPPs needed only to bid zero to be dispatched, as their PPAs took

[16] The reason that entry occurred (as opposed to merely being threatened) probably had much to do with the incumbents' need to allow competition in order to reduce regulatory pressure. They may have decided that higher prices and more entry was both more profitable and more sustainable than entry deterrence and lower profits but continued dominance. It is also notable than half the CCGT build came from the incumbents, suggesting that it was economic compared to at least some existing plant, given existing sulphur emissions limits.

the form of Contracts for Differences.[17] It was claimed, illogically (Newbery, 1998b) that because they bid zero they were not playing a full part in setting the Pool price.

The other major factor facilitating entry was the rapid increase in gas competition and subsequent fall in gas prices. After various MMC inquiries, gas transmission was unbundled from production and supply and subject to regulated Third Party Access. Gas-fired CCGT is almost everywhere the least-cost form of entry, and would certainly be in Italy, provided IPPs could gain access to gas at market clearing gas prices. This is more difficult if the incumbents control access to the network (and hence access to other suppliers, and especially to imports), as they can then price-discriminate in the final market. If the gas incumbents take all the rents from selling electricity in a market whose prices are high because of market power (and high-cost generation), then electricity prices will remain high and entry will be much reduced (and perhaps confined to the gas incumbents). Making the electricity market contestable is thus greatly aided by gas liberalisation.

The importance of gas liberalisation

The gas industry has been far more successful in resisting liberalisation, both because its cost structure is more opaque, and because of the evident importance of long-term contracts to finance production and develop the infrastructure. Import dependence raises security issues that are also logically handled by long-term contracts. The fact that while electricity fails to safety while gas fails to danger favours large vertically integrated concerns whose reputation delivers safety. Finally, compared to the US, the European gas market was until recently relatively immature. Whereas Continental Europe was dominated by a small number of mainly state-owned enterprises, the US had over 8,000 producers, with the 40 largest accounting for only 57% of 1990 gas production. They were connected to more than 1,600 Local Distribution Companies through 44 major interstate pipeline systems and hundreds of smaller pipeline companies (IEA, 1994). In an immature market the main emphasis is on building the network and connecting customers rapidly, so there is likely to be relatively little interconnection and spare capacity that would allow spot markets to develop.

Traditional monopoly gas suppliers typically sell gas at prices linked to the alternative fuel cost of their customer, and this ability to price discriminate allows them to extract substantial rents that they are anxious to protect. Britain has, as a result of a decade of regulatory activism, made unbundling a less unattractive alternative for the original monopolist, British Gas. This was possible as Britain reached maturity (in the sense of a dense and adequate network) before privatisation. With a variety of different producers delivering into a flexible and eventually unbundled delivery system, combined with rapid demand growth for electricity generation, liberalisation delivered gas-on-gas competition that lowered prices and de-linked them from other energy prices, particularly oil (Newbery, 2000). Prices subsequently rose to European levels when the producers built the Gas Interconnector

[17] A CfD for *Q* MW with a strike price *P* entitles the holder to receive *Q**(*P*-PPP) when the Pool Purchase Price is PPP. The IPP would receive PPP/MWh directly from the Pool if declared available for dispatch, thus allowing a zero bid to ensure dispatch (and if constrained off would receive *PPP – bidprice*, or again *PPP*).

to the Continent, allowing them access to a market still linked (at a higher level) to the oil price.

The benefits from similarly liberalising the Continental gas market are likely to be at least as dramatic. As in Britain, a major beneficiary should be the electricity industry, but again the challenges are considerable. Once transmission is unbundled from production and retail, regulated Third Party Access no longer runs into such strong resistance from the companies that control access to protect rents. That in turn opens the prospect of spot markets and gas-on-gas competition to emerge, eroding the need to link gas contracts to verifiable oil prices. However, to reach that stage, the companies, many of which are in the private sector, have to be persuaded to accept unbundling. As this would erode their rents, this will not be easy. It took a decade of competition inquiries and legislative activism to achieve it in Britain, and rather longer in the U.S., where it was finally precipitated by the serious market perversities resulting from policy responses to earlier oil price shocks.

If this is successful, the next challenge is to secure adequate long-term investment in transmission and storage. The latter can be mandated, but the former requires decisions on routes and capacities to meet an unpredictable future spatial pattern of supply and demand. This can be managed by setting transport tariffs at LRMC and requiring the regulated transmission company to meet demand, providing the company has a guarantee that it can recover (the efficient level of) investment costs. The idea of auctioning off future capacity to guide investment decisions has an obvious appeal in a liberalised market, but may run into similar problems of under-provision that concerns policy analysts in the electricity market (McDaniel and Neuhoff, 2002).

Nevertheless, if these obstacles can be overcome, the benefits would be considerable, for it is normally cheaper to move gas by pipeline than electricity by wire. Although international coal prices are such that coal is normally competitive against gas on variable costs, the average cost of new CCGT is considerably lower than new coal, and certainly new nuclear power. Once European electricity prices rise to cover the cost of new CCGT capacity, entry into each country near demand centres is the logical consequence, provided entry barriers or perverse access charges do not hinder it. The most obvious barrier to entry is access to gas on contractually cost-reflective terms. Unfortunately, cost-reflective tariffs run counter to a long history of value-based pricing (i.e. charging the individual consumer the maximum he is willing to bear).

If each country can acquire new generation on similar terms (as implied by the low marginal cost of gas transport), then local demand/supply imbalances can be rectified, and the need for electricity (as opposed to gas) interconnection is reduced. If the wholesale electricity market is kept contestable (and barriers to entry caused by vertical integration and poorly designed wholesale markets, such as NETA, discouraged or overturned), then entry threats (and actual entry) should keep the average price at LRMC while facilitating investment. Competitive pricing (or at least the prospect of gradually moving towards competitive pricing as entry occurs) will then be on offer, even if the initial structure were unsatisfactory, as in Italy and some other countries. As an additional bonus, security of supply in electricity will then be assured at the country level and the objective of subsidiarity will have been achieved.

Improving interconnection

The obvious response to domestic market power and price dispersion across Europe by the Commission and external observers (Bergman et.al. 1999) is to argue for increased interconnector capacity. Interconnection allows generating companies abroad to compete with possibly dominant domestic generators, mitigating market power (Newbery, 2002a). At present only 8% of EU electricity consumption is traded across country borders. Figure 2 above showed how small available import capacity is. If the ESI cannot be restructured at the time of liberalisation, and if gas liberalisation is delayed, then the swiftest way of making the domestic market more competitive is to increase interconnection. The net benefits at the EU level may be modest, amounting to the improvement in EU-wide dispatch, substituting cheaper for more expensive generation.[18] The reduction in deadweight loss from lower prices will be small as demand is so inelastic, with the main effect being a transfer from producers to consumers as the market price falls with increased competition and lower system costs. For consumers in an importing country the gain can be appreciable, but it may be at the expense of those in the exporting country. Consumers in countries like Italy and The Netherlands thus gain from increased interconnection, but those in France and Germany may lose if wholesale prices moved to the EU average. If, as expected, imports lower domestic prices, then vertically integrated generation/transmission importers will lose and may block interconnector investment. Unbundling transmission from generation on both sides of the border is therefore an important step in reaching agreement to strengthen interconnection.

The main gain from increased interconnection is therefore rather indirect, for spare capacity makes markets more competitive and reduces market power (though in tight markets like Italy the increased system security could be extremely valuable). Spare transmission capacity may be considered evidence of inefficiency in a tightly-managed centrally dispatched system, and regulators will require encouragement to allow transmission companies to over-provision transmission. The whole thrust of price-cap regulation is to eliminate ‘gold-plating’ and over-capacity, so considerable care will be required to design suitable forms of transmission regulation. .

There is a danger that improving cross-border transmission capacity will provoke further concentration. If generators from one country are to reduce the risk of selling to another country, they will benefit from integrating both into generation (to hedge the local spot market price variations) and into supply. Cross-border ownership is likely to amplify market power on the interconnectors unless market rules are carefully designed (Gilbert, Neuhoff and Newbery, 2002). It is certainly more difficult for National Regulatory Authorities (NRAs) to properly monitor companies that may engage in market-relevant activities outside the country and jurisdiction of the NRA.

[18] More interconnector capacity improves European system security in the short-run, but most existing capacity has been primarily driven by this benefit. In the longer run more capacity may undermine individual responsibility for providing sufficient domestic supply security by making system security more of a public good.

Cross-border acquisitions typically are the responsibility of Brussels, rather than individual competition authorities, and that may cause further concerns. Some countries may consider that their local competition authorities will pay greater attention to the specifics of electricity markets and less to jurisdictional precedence from dissimilar markets than the European Commission.

Regulators have an important role in setting the access rules for interconnection and also in designing the auctions to allocate scarce capacity. If importing generators with market power obtain additional interconnector capacity, they will increase the amount of electricity sold at the domestic spot price, and this will provide them with additional incentives to increase prices (by reducing supply offered at any price), even when there is a 'use-it-or-lose-it' rule for interconnector capacity rights. Gilbert, Neuhoff and Newbery (2002) show that single price auctions are superior to pay-as-bid auctions in mitigating market power as they allow competitive arbitrageurs to outbid generators where generators may otherwise secure interconnector capacity that amplifies their market power.

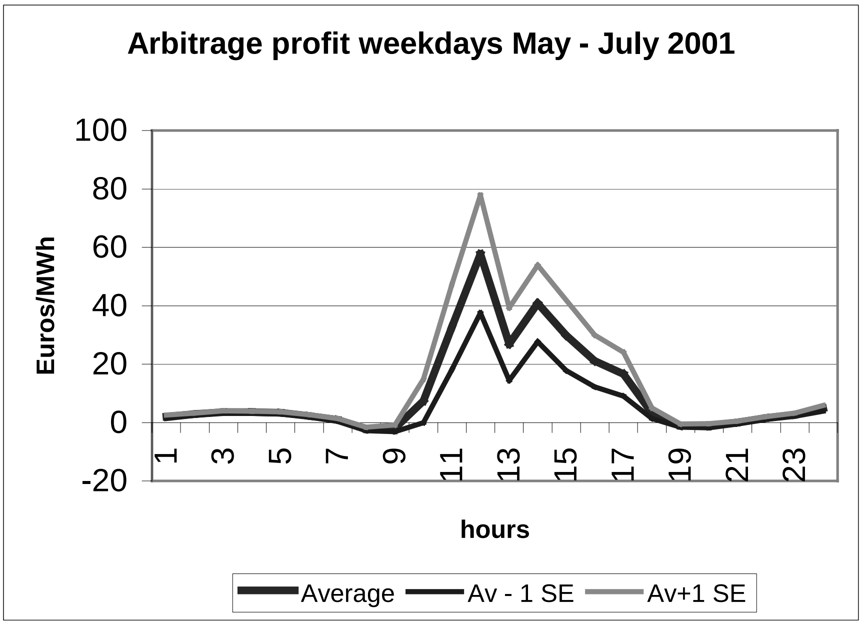

Figure 6 Arbitrage profit on the German-Dutch Interconnector auction

The proof relies on efficient arbitrage, and the evidence, shown in Figure 6 from the German-Dutch interconnector auction, suggests that arbitrage is still not efficient. The figure shows the average profit of systematically buying 1 MWh at each hour in the day-ahead spot market in Germany, buying 1 MW of interconnector capacity in the auction for that hour, and then selling in the Amsterdam spot market, for every day of the months of May-July, 2001. The top and bottom line give the average +/-one standard deviation, and show that although the trading strategy will not yield profits every day, over time the risk of loss in the period 11am-5pm are very small, and the chance of considerable profit quite high.

In the absence of efficient arbitrageurs, it would be preferable to exclude importing generators from the auction. On the other hand there are benefits in allowing exporting generators with market power in securing export capacity, as this precommits them (in the same way as forward contracts) to a more pro-competitive bidding strategy. Matters are more complex in meshed networks, where a careful design of financial transmission contracts may mitigate market power, by defining a reference node whose price is least influenced by actions of generators with significant market power. The main finding of their research is that ‘use-it-or-lose-it’ requirements and making physical contracts obligations, not options,[19] single-price rather than ‘pay-as-bid’ auctions, netting,[20] and efficient arbitrage all mitigate market power.

Electricity market dynamics can be (perhaps simplistically) described as the pursuit of risk reduction and margin defence. Any attempt to create more competition will provoke counter-responses that may store up future problems if not anticipated. Ending the franchise may solve some problems (removing the opportunity for stranding contracts on the captive market) but create others (higher retail margins, more vertical integration and hence barriers to entry by smaller or less specialised firms). Increased interconnection would undoubtedly bring substantial benefits at probably low cost. The lack of past impulses to, or agreed mechanisms to pay for, interconnection almost certainly means that Europe is under-supplied with such links. A tough-minded pro-competitive Commission may even be able to resist further concentration that would become more attractive the more tightly interconnected markets became.

Transmission investment is likely to be slow, both because of environmental protests (that have held up needed interconnection over the Pyranees for decades), and because of the need for Transmission System Operators in adjacent countries to agree tariffs and finance. In the short run, then, regulation may be required to prevent market abuses rather than relying on competition to restrain prices.

Mitigating market power by regulation

The US has the advantage that FERC has the legal power to intervene when prices are deemed "unjust and unreasonable", as it did in California at the end of 2000 (Wolak, 2001). The EU lacks that power, and most EU member countries have not yet adequately addressed this problem. The British regulator, Ofgem, attempted to introduce a Market Abuse Licence Condition in 2000, but two generators successfully appealed to the Competition Commission, so the condition was abandoned. Britain had, by EU standards, a relatively unconcentrated market at that time. Many EU countries (and The Netherlands is an example) lack even the requirement that generators hold licences which require the disclosure of market relevant information to the regulator and whose conditions can be modified to address market power issues.

Several countries like Italy wish to liberalise the market starting from a very unpromising initial condition of tight domestic capacity, inadequate import capacity, concentrated market power, and a relatively illiberal gas market, and need guidance on how to make the transition to a lightly regulated wholesale electricity market. The first

[19] An obligation to relieve a congestion constraint means that failure to deliver is subject to imbalance charges, whereas an option allows the holder to deliver electricity only if profitable.

[20] That is, directionally summing all bids for interconnection before determining the amount of capacity to be allocated, and charging directional prices (positive for flows in one direction, equal but negative for those in the other direction).

point to note is that although contracts restrain market power in the spot market, the contract market itself will reflect the future equilibrium spot prices. If demand is tight then spot prices will be high even if the market is fragmented. If the market is concentrated, then spot prices and hence contract prices will be high unless something is done to restrain the exercise of market power.

Britain again offers some guidance, for the early stages of the transition were covered by extensive vesting contracts (i.e. contracts put in place before the day the new companies were vested). Provided contract coverage is (almost) complete, the incentive to manipulate spot markets is (almost) eliminated. Providing franchise distribution companies with suitable contracts is straightforward, and surely absolutely essential in these circumstances. Providing contract coverage to eligible customers may be more problematic, but requiring generators to offer such contracts under standard terms to be approved (and possibly also designed) by the regulator should solve the problem. Any customer who is happy to negotiate his own contracts or buy spot is then free to do so.

This was the advice offered by Frank Wolak, as chair of the California Independent System Operator Market Surveillance Committee (MSC), when faced with the prospect of tight markets for some years to come. The MSC proposal was to require that the three Californian investor-owned utilities that still possessed market power sell at cost-based rates (as under the default system of regulation required by the Federal Power Act), and to only allow other generators to sell in California at market-based (as opposed to regulated rates) if they offer 2-year forward contracts at 'competitive prices' (determined according to a defined methodology, and about $54/MWh), for 75% of their total capacity. In exchange, they would be free to sell the balance at the market-clearing spot price.

All generators would file an annual maintenance schedule for outages, and except then would be required to bid all capacity into the day-ahead spot market (or would have a competitive cost-based bid entered instead). Any outage would then require the generator to pay the excess of the spot over bid price to compensate buyers, providing a strong incentive to not withhold capacity to drive up prices. Consumers would be entitled to buy 85% of their corresponding 2000 demand (by hour, day, month or however previously contracted) at the corresponding 2000 price. Suppliers would then presumably be entitled to acquire the favourably priced contracts to cover this obligation, solving the problem of how to prevent these contracts retailing at their substantially higher scarcity price.

This solution has an obvious appeal to economists. It preserves price incentives where they matter, at the margin, while capturing the intramarginal scarcity rents for consumers, as required for political sustainability. It has much in common with the 'dual-price' system used to introduce market prices for State enterprises into the Chinese economy (Newbery, 1993).[21] It caps the upside returns but does not underwrite the downside risks, and so may encourage underinvestment unless the contract price cap is correctly set. The correct strike price for the contracts will depend on whether these are effectively one-sided or two-sided contracts (i.e. whether they only cap the price or carry

[21] Enterprises were required to sell planned output at fixed prices, and allowed to sell any surplus at the free market price.

the obligation to pay the strike price even if it is above the spot price). One-sided contracts, like those proposed, either require a higher cap or an option payment to be equivalent to a competitive price.

This solution would seem attractive as a means of both limiting market power in the medium run while providing additional incentive for dominant incumbents to divest and hence escape the price cap earlier than otherwise. It might usefully be associated with a restriction on building new capacity unless in exchange for sales of existing capacity. The requirement to sell rather than withdraw ensures that other generating companies acquire potentially competitive plant, while allowing generating companies to rebalance their plant portfolio towards a more similar range of plant, thus reducing fuel price and environmental regulatory risk and making the market more competitive.[22]

If the market is to remain contestable, then it helps to have credible counter-parties for long-term contracts with new IPPs. In Britain the RECs, with their significant regulatory asset base and the ability to pass through wholesale prices into the captive franchise market, served that role. In California, the distribution companies had their final prices capped but were discouraged from contracting, so they were exposed to wholesale price risk and rapidly went bankrupt when prices rose. The logical regulatory solution is therefore to retain the domestic franchise, to allow cost pass-through while providing incentives for efficient contacting. In The Netherlands that is provided by yardstick regulation of retail prices: suppliers have their retail prices capped by a weighted average of their own contracts and those signed by all other suppliers.[23]

Conclusions

European electricity markets are, with some exceptions, not well equipped to deliver sustainable and competitive outcomes. Too many countries have dominant incumbents protected from foreign competition by inadequate interconnector capacity, and in some cases such as Italy the reserve margins are very low at the peak. The evidence from California suggests that even in apparently unconcentrated markets, market power is a serious problem in tight markets. Mitigating market power is therefore likely to be a major concern of regulators and competition authorities for the foreseeable future, until markets have become less concentrated, import capacity has been increased, and reserve margins made adequate. The best strategy is to divest generation from the dominant incumbent at the time of liberalisation, to create sufficiently many competing generators (aiming at an HHI in price-setting capacity below 1800). If this is not possible (or the opportunity has been lost), making entry contestable and increasing interconnection are the obvious ways of allowing more generators to compete. For entry to be contestable, access to gas on equitable and cost-reflective terms is a precondition, greatly aided by unbundling gas transmission from production and supply, and offering regulated Third Party Access. Ancillary gas services (balancing, storage, flexibility) need to be either made competitive or regulated at cost-reflective tariffs to ensure that the gas suppliers do not extract monopoly rents from the electricity market.

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[22] If competing generators have a similar range of plants in terms of unit costs then they can compete over a wider range of demand levels and system marginal price.

[23] In order not to allow cherry-picking in the allocation of contracts between the eligible and franchise market, all contracts are considered in the yardstick.

In the short to medium run, if there are inadequate reserves and import capacity, any market structure is likely to suffer from high prices if unregulated. Generators with significant market power (defined by their ability to raise prices appreciably above the competitive level for at least some hours so that the average price over the year exceeds the cost at which new entry is profitable) should be required to offer contracts of sufficient variety and flexibility at prices related to long-run marginal cost, until reserve margins improve, or generators divest plant to the point that they no longer possess significant market power. This condition provides incentives for making the market more competitive and hence addressing one of the potential underlying problems.

Regulators may be tempted to offer other favours in exchange for divesting plant, such as cross-border horizontal or vertical mergers and domestic vertical mergers with supply. These need to be considered carefully, for they involve a trade-off between the loss of some market power in one market but possibly reduced competition in others – either in cross-border trade or in making entry of non-vertically integrated IPPs more risky and more difficult. Newbery (1998b) criticised the New Electricity Trading Arrangements precisely because they encouraged vertical integration and made entry less contestable.

If consumers are to be offered access to a range of suppliers, transmission will have to be separated from transmission, ideally under different ownership. Unbundling creates risks that require suitable hedging contracts. Supply competition shortens contract length and may prejudice long-term investment in generation or entry by new competitors. It may therefore be desirable to retain the domestic franchise (with suitable yardstick regulation of contracts) in order to allow longer-term PPAs that facilitate entry and reduce investment risks.

Regulators are learning that competition is more fragile and prone to manipulation in electricity markets than normal (storable) product markets, but are unsure how to react. The US tradition in which FERC retains the power to suspend market-based pricing when it is "unjust and unreasonable" reflects a very different tradition to that motivating liberalisation elsewhere. The US tradition may either reflect a century of regulatory capture, or the evolutionarily stable outcome of the political process. If market liberalisation is the goal, rather than the means to a regulatory end, then regulators and competition authorities will need greater understanding of the special features of electricity markets, and will need to develop suitable regulatory tools, such as information obligations and licence conditions, to identify and address suspected market manipulation.

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