Market Design

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Refining Market Design

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Introduction

The goals of market design include, as a pre-condition of continued popular and therefore political support, confidence in security of high quality supply at sustainably competitive prices. Sustainability here refers both to the ability of the sector to finance and deliver efficient and reliable electricity supply and in the environmental sense of reducing greenhouse gas emissions. Efficiency requires that energy, capacity and ancillary services are at least cost but at prices that allow adequate investment to be financed by the private sector. This in turn requires that the markets provide price signals for entry of new generating capacity that is efficient in location, timing, scale and fuel choice, and for dispatch that minimises social costs, including environmental costs. Market integration in turn means that European costs are minimised, trade takes place guided by comparative advantage, importing competition into more concentrated markets.

Before 1990, almost every electricity supply industry was vertically integrated with a captive franchise market, either state-owned (the majority case) or under regulated private ownership (particularly in the US, but also in Germany). In both cases the form of regulation was effectively cost-of-service regulation.[2] Electricity liberalisation starts from the premise that while transmission and distribution networks are natural monopolies requiring regulation, generation and supply (or retailing) are potentially competitive activities. Effective competition is superior to regulation in providing incentives for efficiency that are then passed on to consumers in lower prices. Vertical unbundling also allows for incentive regulation (such as Britain's price-cap regulation) of transmission and distribution networks and offers the prospect of greater efficiency than traditional cost-of-service regulation. Although electricity networks were typically synchronised over wide areas (e.g. over most of Western Europe under the UCTE (Union for the Co-ordination of Transmission of Electricity), and within the three synchronised networks that cover the US), trade across the borders of areas under different transmission system operators (TSOs) were mostly guided by security rather than economic considerations. Competition and trade are obvious

[1] This paper draws directly on the papers presented at the Cambridge SESSA, cited in the references. I am indebted to Ignacio Perez Arriaga and Jean-Michel Glachant, as well as other participants, for their helpful comments.

[2] In the US before 1973, rapid technical progress and stable fuel costs combined with regulatory lags provided similar incentives for efficiency gains as price-cap regulation.

handmaidens, so improving cross-border electricity trade offers additional prospective efficiency gains.[3]

The challenge facing liberalisation

Electricity differs from standard commodities in important respects, in that it cannot be stored economically (except as water in a hydro system) and supply and demand must be instantaneously balanced by a system operator (another natural monopoly function). In addition, demand is typically very inelastic in the short run, with a large fraction of consumers not able to face or respond to spot or scarcity prices, and from whom supply cannot be withheld. Power lines must be operated within their limited capacity, and if quality parameters (frequency, voltage, phase angle) move outside tight limits, cascading power cuts may result. Power stations are capital intensive (typically average total costs can be twice variable cost), lumpy and durable (30-50 years), often requiring considerable lead times to secure planning permission and complete construction.[4] In short, managing an interconnected electricity system presents considerable challenges that have in the past argued against using decentralised market mechanisms to deliver power and guide operation and investment decisions.

Liberalisation – the process begins

Serious electricity liberalisation in OECD countries started with Britain's restructuring and privatisation of 1990, demonstrating that unbundling and creating wholesale electricity markets was feasible. In the US, liberalisation started after the Energy Policy Act of 1992, and more decisively after California started exploring liberalisation options from April 1994 (Joskow, 2004). After the British experience, and liberalisation in Norway in 1991 (not to mention Chile, Argentina, New Zealand and Australia), the European Commission decided to introduce Directives to open up the European energy markets (Jamasb and Pollitt, 2005). The Electricity Directive published in 1996 forced the pace in a number of countries that until the Directive had not actively pursued liberalisation (e.g. the Netherlands, see van Damme 2005). The design of reform remained very much up to individual jurisdictions until 2003 when the next Electricity Directive and FERC's Standard Market Design attempted to prescribe best practice market design and facilitate more efficient cross-border trade.

The process of reform has varied widely across the EU and US, and offers the prospect of learning from the various experiences. To that end, SESSA Work Package 2 commissioned papers from leading energy economists for a conference, *Refining Market Design*, held in Cambridge, England, on 14-15 July 2004. The objective was to examine the performance of different electricity market designs in various European countries and the US. This chapter first reviews the evidence provided in those papers on lessons for good market

[3] The challenges involved in realising these gains and the options for improving cross-border trade are the subject of a special issue of *Utilities Policy* published in 2005. A list of acronyms is given at the end of this chapter.

[4] In all dimensions, nuclear and hydro plants are at the upper extreme, while gas-fired combined cycle turbines (CCGT) have relaxed most of these constraints, thus greatly favouring liberalization.

design (and mistakes to avoid), and then summarises these lessons in a series of prescriptions. Many of the original papers presented at that conference have been published in a special issue of *The Energy Journal* and will be referred to by author below.

The EU: market opening and market power

Recent EC benchmarking reports provide a useful starting point for an overview of European market integration. These show that the EU had already achieved (on paper at least) about 60% market opening by 1999 (by units sold) and 90% by 2004, substantially in excess of the legal minima. However, in some cases, notably Germany, this apparent market opening lead to either relatively low levels of switching or losses by entrants and their subsequent withdrawal, suggesting that the market opening was more legal than actual. A better measure of effective market opening would be the sustainability of switching between suppliers, and the extent to which new suppliers were able to win market share from incumbents.

Jamasb and Pollitt (2005) argue that the centralised approach to market liberalisation through the Electricity Directives has succeeded in maintaining the pace of reform in the original EU-15 and in a number of associated and accession countries, and in achieving a degree of standardisation of structures, institutions, and rules in national markets. However, they point to the problems created by initially concentrated market structures and the low level of interconnection that reduces the scope for importing competition. This initially concentrated market structure has been exacerbated by a large number of subsequent mergers that have been waved through, Real prices fell from 1997 to 2004 (but so did electricity fuel costs). Nevertheless, the variation in network charges and wholesale prices across the EU-15 remains is still substantial, reflecting the scarcity of interconnection and the lack of cross-country benchmarking for regulating network charges.[5] Part of the problem lies in the uncompetitive nature of the gas market. If the gas market were more competitive (and transmission and storage charges regulated more effectively), the price of gas should be more uniform across Europe, as gas transmission costs are relatively low. That would mean that new entrants into electricity generation would face similar costs and would encourage price convergence. At present one must conclude that the single electricity market, in which price differences across space can be attributed to justified and reasonable cost differences, has not yet arrived.

The United States: integrating disparate markets[6]

The US is an excellent test-bed for ideas of market liberalisation and integration, although the institutional framework is very different from that of the EU, and this must be taken into account when drawing comparative lessons. The US and EU15 have roughly similar sized

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[5] It is not necessarily undesirable for countries and municipalities to tax transmission use, nor to take different views on the valuation of the partly depreciated assets, although in some cases there is clearly an intention to accrue company profits in the network part of the business in order to disadvantage competitors in the potentially competitive segments of generation and supply.

[6] This section draws heavily on Joskow (2005) and his presentations posted on the SESSA website.

electricity sectors: about 600 GW in the EU-15 in 2000, and 656 GW counting the accession countries; compared to about 650 GW in the US in 1996, 75% of which was investor owned. In 1995 there were about 140 separate control areas responsible for operating portions of the three synchronised AC networks (the Eastern, Western and Texas Interconnects), in contrast to the EU with its far fewer largely national control areas, also operating in three synchronised networks (UCPTE, the Nordic Market and Britain). Clearly this balkanisation in the US impeded the efficient generation and transmission of electricity, as transmission access was effectively negotiated, charges were pancaked (i.e. each transmission owner required payment), and cost of service regulation reduced the incentive to secure least-cost power from out of area.

US reform really started with the Energy Policy Act of 1992, followed by California's proposals of 1994 that demonstrated the need for unbundling of transmission from generation. The Federal Energy Regulatory Commission, FERC, had a commanding role to play with its jurisdiction over transmission (and actions that affected electricity flows between states, covering most aspects of market design in the AC interconnected parts of the US). The importance of unbundling led to FERC's Order 888/889 of 1996 that mandated regulated third party access to transmission and an Open Access Same-time Information System (OASIS) to facilitate trade. These supported but did not enforce moves to liberalise and unbundle local markets, as in California and the Northeast. Order 2000 sought to extend the Northeast model of Independent System Operators (ISOs) to the rest of the country, and for transmission owning utilities to join Regional Transmission Organisations, but made slow progress.

Between 1996 and 2003 the US wholesale electricity market changed dramatically, compared to the previous half-century. About 100 GW of generation were divested and deregulated by 2003, of which 85 GW were transferred to unregulated affiliates. Between 2000 and 2003 alone 175 GW of new generating capacity (80% merchant) were added (rising to 218 GW by end 2004), so that 45% of investor-owned generation was unregulated by 2003. Real residential and industrial electricity prices continued their steady decline to 2003 that started with the Public Utility Regulatory Policy Act (PURPA) of 1978, even after controlling for fuel price changes. Bushnell and Wolfram (2005) find that fuel efficiency improved by about 2% in response to the improved incentives of deregulation, and that ownership transfers per se had little effect.

Progress towards integrating markets: FERC's Standard Market Design

In July 2002 FERC started a new rule-making proceeding to introduce a Standard Market Design (SMD), based largely on the PJM model,[7] with day-ahead and real time nodal pricing set by an Independent Transmission Provider. It placed an obligation on all Load Serving Entities (LSEs) to secure adequate resources (generation and transmission capacity) to meet their forecast demand and reserve requirements. The wholesale market would be closely monitored for abuses of market power and subject to $1000/MWh price cap. This cap is

[7] originally comprising **P**ennsylvania, New **J**ersey and **M**aryland, but now considerably broader.

supplemented by a variety of other measures, from must-run contracts, must offer provisions, and automatic bid mitigation procedures if an individual generating unit is attempting to exploit its transient market power in a temporary load pocket. The latter is potentially more visible and attracts more consumer concern under nodal pricing rather than in the European model of zonal pricing, discussed below.

Nodal pricing involves computing the scarcity price of delivering power to or withdrawing power from any node, and can be computed readily if generators truthfully reveal their short-run marginal costs. For short-run congestion management there is agreement that a system relying on LMPs works and is efficient (provided that bids are competitive), and it is easy to extend to neighbouring dispatch areas if they also operate LMP and are willing to allow a single ISO to compute the nodal prices.[8] The obvious problem is that generators may not reveal their true variable costs, hence the perceived need for automatic bid mitigation.

Mitigating market power and ensuring capacity adequacy

The requirement that LSEs should contract ahead for capacity reflects a concern that liberalised electricity markets within the US regulatory structure will fail to deliver adequate and timely investment, and it is important to recognise the difference between the US and the EU in this respect. The 1935 Energy Act continues to place a duty on regulators to ensure that prices are "just and reasonable". FERC interpreted this to require liberalising jurisdictions to demonstrate that they had created adequately competitive wholesale markets, on the sound principle that competitive prices were by definition "just and reasonable". Given the special characteristics of electricity, and the necessarily limited capacity of transmission systems, transient and possibly more enduring market power is almost inevitable in some parts of the network, once generators are free to bid rather than being dispatched on the basis of variable costs. FERC thus arguably has a duty to ensure that there are mechanisms to mitigate even transient market power, hence the variety of mechanisms in PJM and similar markets. The threat of regulatory intervention if prices rise "unreasonably" and the experience of these various mechanisms undermine the ability of generators to recover their fixed costs. In the period from 1999 to 2001 generators in the Northeast fell far short of earning sufficient revenue above variable costs to adequately compensate their capacity costs.

There is thus a genuine problem in convincing investors to build new capacity (either base-load or peaking) if the market rules are so skewed against cost recovery, hence the need to require consumers (or their representatives, the LSEs) to contract ahead for typically 118% of peak demand, and thus to pay whatever it takes to persuade adequate capacity to be made available. The design of these capacity obligations has been fraught, given that the capacity should be encouraged to be most available when most needed, and that it should be deliverable to the consumers that need it. As customers can change their LSE, a secondary market in capacity obligations is necessary, and given the inelastic nature of demand (e.g.

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[8] See Newbery (2005a), Brunekreeft et al (2005) and the special issue of *Utilities Policy* (June, 2005) on Transmission Pricing.

118% of peak load), capacity prices are both volatile and potentially manipulable. Various modifications to meet these requirements and deal with market power problems continue to be discussed before FERC, including Reliability Options of the kind proposed for other markets as a way of both rewarding rarely-run plant while insuring consumers against high price spikes.[9]

The pressure for electricity reform in the US has been driven largely by states with high electricity prices, with little enthusiasm from states enjoying low prices (not surprisingly, as market integration that encourages price convergence would benefit consumer/voters in the former but harm them in the latter). FERC's role has been seen as an infringement on states' rights, and the Californian melt-down of 2000-01 did nothing to inspire confidence in the ability of liberalised markets to deliver secure and reliable power. The August 2003 blackout that affected a wide swathe of the Northeast added more weight to opponents of liberalisation and caused FERC to draw back from making the SMD mandatory. Nevertheless, PJM continues to expand and adapt to new challenges, which include ensuring generation adequacy and more interconnecting transmission investment.

The early days of deregulation were marked by a gradual adaptation of the rules of the game (grid codes, market rules, regulatory interventions) to an increasingly boisterous attitude to trading, made subsequently infamous by Enron. The initial over-enthusiasm for investment came too late to help California but the resulting price collapse, bankruptcies and market shake-out, not to mention litigation over the price of contracts signed under "duress" in California, made both companies and banks wary of financing new investment. That, and the regulatory restraints on high prices prompted by earlier market abuses have chilled the investment climate and necessitated capacity requirements or their equivalent.

Lessons for Europe from the US experience

The US may not provide a good regulatory model for generation investment but it faces the same challenges as the EU when it comes to transmission investment. Both the US and the EU face the same problem of integrating different dispatch areas whose transmission grids were designed to deliver power within area and not to facilitate least-cost dispatch over an entire continent. The problem with financing transmission investment is who should pay for interconnections between areas, whose construction has rather indirect and poorly priced benefits that are differentially distributed – improved reliability, lower reserve margins, and reduced market power. The US attempt at encouraging merchant investment (financed on the back of the revenue streams produced by nodal price differences) has been less successful than hoped, and tends to be undermined by regulatory investments taken for security or reliability reasons (and hence chargeable through the regulated transmission tariffs). As elsewhere, environmental opposition to unsightly pylons hampers needed investment, although the Californian shortage and the major 2003 black-out may have reduced such opposition somewhat.

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[9] See e.g. Perez-Arriaga et al (2001) and the report for Dutch electricity regulator by Vazquez et. al (2003).

The PJM model of nodal pricing seems particularly valuable for transmission pricing and investment as it solves the “seams” issue (or the problem of paying for interconnection between dispatch areas) and appears to be a model that can be extended gradually over geographic space, although it leaves the major issue of complete recovery of total transmission costs unsolved. Europe is still some way from embracing the nodal pricing model, perhaps because it sits too comfortably with an interventionist approach to pricing and market power mitigation, with all the compensating regulatory rules and devices needed to offset the objectionable effects of local market power. As the US wrestles with market and regulatory design issues, her experience will continue to be useful, if carefully interpreted, for the European debate.

Britain: addressing market concentration and adapting market design

Newbery (2005b) outlines the history and experience of the exemplar of electricity market reform, contrasting the effects of the different models chosen in England and Wales (ownership unbundling of transmission) and Scotland (which retained the two vertically integrated companies). Britain provides the longest experience of European liberalisation and restructuring and therefore an important source of lessons. More to the present point, she provides a natural experiment for the choice of wholesale market design.

The first lesson one can draw from the British experience is that unbundling ownership of transmission from generation has been critical in enabling competition to deliver cost reductions in England and Wales, in contrast to vertical integration in Scotland where there appeared to be no improvement in efficiency after privatisation (summarised in Newbery, 2005b, drawing on work of Newbery and Pollitt, 1997).

The original Electricity Pool (a centrally dispatched compulsory day-ahead half-hourly market with a capacity payment) was set up in 1990 at the date of privatisation and restructuring. Generators submitted a single supply function one day ahead for each generating unit with five shape parameters (start-up costs, no-load cost, and three incremental costs) as well as a large number of technical details (minimum load, ramp-up rates, etc). The unit’s offer would remain valid for the whole set of 48 half-hourly periods starting at midnight the next day. The System Operator (National Grid Co) then found the system marginal price (SMP) for each half-hour (paid to all units called on to generate) as the most expensive bid accepted, ignoring transmission constraints. A payment for capacity declared available (and thus subject to dispatch) was added to the SMP to give the Pool Purchase Price, and a further charge for ancillary services was added to give the Pool Selling Price.[10] These prices and dispatch instructions were published at 5pm the day ahead.

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[10] The Capacity Payment was equal to the Value of Lost Load (VOLL) *less* SMP (or bid price) times the Loss of Load Probability (LOLP), providing strong incentives to be available when the system is tight. A large fraction of revenue from capacity payments thus are earned in a small number of hours in the year. Ancillary services include the cost of resolving transmission constraints where plant that must run is paid its bid price and plant backed down is paid the difference between the SMP and its bid (i.e. its lost profit).

In addition to the Pool, which acted both as a commodity spot market producing the reference price and a balancing market, most generators and suppliers signed bilateral financial contracts for varying periods to hedge the risk of pool price volatility. The standard contract was a Contract for Differences (CfD) which specified a strike price (£/MWh) and volume (MWh), and was settled with reference to the pool price, so that generators were not required to produce electricity in order to meet their contractual obligations. These CfDs could be one or two-sided, offering different hedging possibilities.[11]

The initial market structure in England and Wales was highly concentrated, with two fossil generators setting the price over 90% of the time. One of the most useful lessons from the British experience is how market power manifested itself and how the regulator dealt with these problems. Although the two price-setting companies kept prices lower than might have been expected given their dominance, they clearly had and exercised market power, increasing the price-cost margin steadily as vesting contracts expired. In response, the generators agreed with the regulator to accept a wholesale (annual average) price cap in 1994 until they found an acceptable way to reduce their market power, which they did by divesting 6,000 MW to a third company in 1996. This did not reduce the price-cost margin, but the attempt of generators to vertically integrate into distribution and supply (to hedge wholesale price risk) required approval from the Competition Commission. This approval was effectively conditional on further divestiture, so the dominant generators traded horizontal market power for vertical integration into supply.

The New Electricity Trading Arrangements replace the Pool

The failure of the price-cost margin to fall, and a belief that the Pool was both manipulable and hard to modify, lead to a review of trading arrangements. In 2001 the Pool was replaced by the New Electricity Trading Arrangements (NETA). NETA involved self-dispatch, voluntary bilateral and OTC markets for contracting, combined with a pay-as-bid average priced balancing mechanism (described below) and no capacity payment. While the US was converging under FERC's Standard Market Design (SMD) on the pool model (with the addition of nodal pricing), Britain abandoned that model and moved more closely towards the dominant European model of decentralised trading through power exchanges (such as the Amsterdam Power Exchange and the EEX).

In the run-up to NETA, continuing plant sales were encouraged by the anticipation (not shared by foreign buyers) that excess entry induced by earlier concentration and high prices would likely undermine the high-price equilibrium, while the uncertainty surrounding the consequences of removing capacity payments in the forthcoming NETA increased the attraction of acquiring sticky domestic customers and selling risky generation. This lead to a remarkably unconcentrated industry shortly before NETA went live in March 2001, and with it the inability of the generators to sustain high price-cost margins. Prices collapsed towards

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[11] Over time the market developed quite sophisticated hedging instruments, for example hedging against prices above a specified strike price for the six most expensive half-hours in a month. The

the end of 2000, demonstrating that market power and high prices were the result of market structure rather than market design, although poor market design could certainly amplify existing market power. Plant withdrawal and rising fuel and carbon prices subsequently increased real wholesale prices to their pre-NETA level, although margins were still somewhat below entry level as of mid 2005.[12]

Can market design address problems of market structure?

The British example points to an apparent problem of determining whether unsatisfactory outcomes (high prices, manipulation of capacity payments, high payments for resolving transmission constraints) were a result of poor market design or poor market structure. The British evidence of increased wholesale competition suggests that where the market design is reasonably sensible (as under the Pool, which although flawed could work quite well in competitive conditions), then market structure is determinative.[13] The exercise of potential market power is moderated by the nature and extent of regulatory scrutiny and the reputation and powers of the competition authorities, and probably also whether ownership is public (as in France and Norway) or private. While Britain has coped very well with wholesale market power, ending the domestic franchise and removing regulation from the retail supply margin has exposed households to considerable increases in those margins, as switching costs appear significant, and vertically integrated companies have been effective in exploiting their power. This message comes out in the evidence from the Nordic countries discussed in the next section.

One issue that continues to attract debate and which remains unresolved is whether capacity payments are necessary to ensure security of supply, or whether they offer additional scope for market manipulation without enhancing security. Newbery (1995) demonstrated that the specific design of capacity payments under the Pool were manipulable if generators had a high enough market share (typically more than 25%, depending on contract positions). One logical alternative to capacity payments is to charge the TSO with ensuring security of supply (specified by a target frequency of loss of load, e.g. load shedding through inadequate capacity not more often than once every ten years). [14]

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ability of the market to devise suitable hedges is relevant to the discussion whether regulators should insist on Reliability Options to protect consumers and reward rarely-run plant (Vasquez et al, 2002).

[12] Fossil electricity generators have required CO_2 emission allowances equal to their annual emissions since January 2005, and the price of these allowances has risen from €7/tonne CO_2 to **€**22/tonne in mid June 2005. The June price would increase the cost of coal-fired generation by €20/MWh and of gas by nearly €10/MWh. While there are provisions for the free allocation to existing facilities and new entrants, investors face risks about the allocation methods in future periods.

[13] Evans and Green (2005) demonstrate econometrically that the while the reduction in concentration had a significant effect on wholesale prices, the switch from the Pool to NETA did not.

[14] There is another related set of issues whether it is better to specify security in quantitative terms (such as the size of the reserve margin) or whether security should be valued (as the value of lost load) and balanced against the cost. The same issue arises repeatedly in liberalised markets when assessing

The British experience is helpful in demonstrating the effectiveness of well-designed incentives for the monopoly TSO function. With such incentives the TSO can choose to contract ahead for reserves and run a balancing market or mechanism to provide real-time scarcity prices that can then feed back into spot and contract markets. The evidence from June 2003 (when winter scarcity was first forecast and forward prices started to increase) suggests that market signals can indicate ahead of time when plant needs to be brought back onto the system. There are remaining doubts whether these prices will signal when new plant needs to be built in enough time, but in practice large irreversible investment decisions are based on analysing market fundamentals, not just current trading views.

The Balancing Mechanism implemented under NETA plays a key role in this price discovery process, and raises important design issues. There are several possibilities – to secure balancing bids and offers through a discriminatory auction (pay-as-bid, as under NETA) or a uniform or last price auction (e.g. as in the Netherlands), and whether to have a single imbalance price or two prices (for being short or long, as under NETA). Theory suggests a single imbalance price secured in a last price auction is the best competitive design but may not be the best choice in the presence of market power.

NETA cost over €1 billion, created an arguably inefficient balancing market, and has reinforced the pressure for vertical integration which leads to lower market liquidity and hence barriers to (merchant) entry. This change in market design was premised on an inadequate cost-benefit study, and it is to be hoped that other countries will learn enough from the evidence it provides to avoid another costly design experiment.

Transmission pricing

Britain also developed a system of transmission pricing that is less than satisfactory, and is proving extremely difficult to reform. British transmission pricing has not therefore changed much since 1990, and continues to maintain the fiction that spot energy is equally valuable no matter where or when it is injected or withdrawn. Generators and consumers pay annual fixed charges that do depend on their location (by zones, of which there are 12-15) and their peak demand or capacity. Transmission losses are socialised. The TSO has to not only ensure energy balance but resolve transmission constraints by accepting offers to generate where there is inadequate supply and bids to reduce output where there is an export constraint. Again these constraint costs are socialised.

The weakness of this method of transmission pricing is that, in contrast to the pre-reform period, transmission losses are not borne by generators, distorting the merit order, while firm access rights reward, rather than penalise, generators in export constrained zones. Scotland is the obvious example, and two successive attempts by the regulator, Offer, to introduce transmission losses were successfully appealed against to the courts. Arguably the intentional complexity of NETA and its core Balancing Mechanism with two cash-out prices

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transmission and other investments, and practice is only cautiously moving from an engineering-based to an economic approach.

prevented the logical reform to nodal pricing when the trading arrangements were changed, and that lost opportunity has also been costly.

Britain has the advantage of a single TSO for the entire synchronised system, for Britain is only connected to other countries by DC links, and so it was reasonably straightforward to design a single system of transmission pricing to handle constraints and the resulting congestion when the industry was restructured in 1990.[15] Other members of the EU are interconnected by AC interconnectors, and flows over these interconnectors depend on the entire pattern of injections and withdrawals at all the nodes or points at which generators or loads are attached. One of the key design issues is how such interconnected and interdependent systems will manage these power flows and handle congestion at the interconnectors.

This system of uniform energy prices and zonal fixed transmission charges can be contrasted with locational marginal pricing (LMP), also known as nodal spot pricing, as practised in PJM and increasingly in other US jurisdictions, following the SMD. LMP fits naturally with a pool-based wholesale market (not necessarily compulsory) but there are concerns that individual nodal prices will be exposed to market power. Nevertheless, Green (2004b) estimates that nodal pricing rather than the British apporach of uniform pricing in the presence of market power would have raised welfare by possibly 1.8%, which is high compared to the gains of restructuring, which Newbery and Pollitt (1995) estimated as equivalent to a permanent reduction in prices of 5-6% in England and Wales.

The Nordic Market: successful cross-border trading

The Nordic system represents an intermediate and simpler solution to congestion management. Nord Pool uses the term market splitting (also called market coupling) to deal with the case in which constraints prevent the Nordic market clearing at a single price, in which case the market is split into pre-defined zones defined by countries or regions within countries. Each zone has a single market clearing price. This model is attractive where separate jurisdictions under different TSOs are again prepared to allow an SO to handle bids into the energy spot market and for using interconnectors to be cleared simultaneously. It appears to work with either a pool model or a power exchange (but it does benefit from a single SO to clear the bids and offers).

Von der Fehr, Amundsen and Bergman (2005) offer evidence from the Nordic market on another critical issue for liberalisation – whether an unregulated generation and supply industry can survive the potential backlash from a period of high prices caused by shortage

[15] Originally England and Wales had the National Grid Company (NGC) as the TSO, with the two Scottish vertically integrated companies trading in the Pool over the Scottish interconnectors, which they owned and managed. Since 2005 the whole of Britain has been dispatched by NGC under BETTA, the British Electricity Trading Arrangements. Although it is in principle easier to reach agreement about trading arrangements with a single national TSO, changes can have large redistributional impacts on generators and consumers and may be successfully opposed through the courts. That is one reason why losses are still socialised although this is clearly an unsatisfactory system.

(in this case of rain for the hydro reservoirs). Since the California meltdown of 2000/1 (also caused in part by low rainfall in the Columbia basin), observers have become sceptical that liberalisation will survive the honeymoon period of adequate reserve margins and resulting low prices. Norway provides an encouraging counter-example of regulatory and political forbearance and of the market response to unexpected price volatility.

Both Norway and Sweden suffered from a supply shock in 2002-2003, due to unexpectedly dry weather. In the second half of 2002, inflow to hydro reservoirs was only 54 per cent of the average of the preceding 20 year period. As a result, reservoir fillings were at a record low at the beginning of the low-inflow/high-demand winter season. Foreseeing tighter market conditions, producers began restricting supply in late autumn and prices started to rise. The (daily average) spot price peaked at 850 NOK/MWh (€115/MWh) in January 2003, two to three times the normal level. High spot prices feed through to consumers, who in some cases faced increases in electricity bills of 50 per cent or more.[16] There was speculation that high prices were the result of abuse of market power, as well as a lack of investment in both generation and transmission in earlier years, and that rationing on a massive scale would be required. As it turned out, no such drastic measures were warranted, as responses from consumers and thermal-power producers balanced the market. Even though prices remained high during most of 2003, market conditions gradually normalised.

Some saw the events of 2002-3 as a warning sign, or indeed as outright proof that the electricity market is flawed. Others consider its performance through this period as evidence that the market has reached maturity and is robust enough to withstand even quite extreme shocks. Von der Fehr, Amundsen and Bergman preferred the latter view. Nevertheless, the supply shock brought to the surface a number of potential weaknesses that warrant careful analysis and which may eventually lead to further improvements in the regulatory framework as well as in other market institutions.

Domestic prices increased rapidly as most Norwegian households bought at prices linked to the wholesale price (with a lag of only two weeks), in contrast to commercial and industrial consumers who typically bought on longer term contracts. Increases in end-user prices had a considerable impact on demand. Roughly speaking, Norwegian demand may be seen as consisting of three segments: the very flexible boiler segment (approx. 5% of the total), the heavily-contracted power-intensive industry (approx. 30%) and the rest (approx. 65%). Demand from the boiler segment – which can easily switch between oil and electricity – fell sharply when prices started to rise in October 2002 and remained low during the winter; all in all, electricity consumption by boilers over the period November 2002 to May 2003 was around one third of that of the corresponding period in 2001-2002. In the energy-intensive industries, some plants stopped production, but the overall response was relatively small,

[16] Note that, since many Nordic consumers rely on electricity for most domestic energy needs, incl. heating, electricity bills tend to make up a considerable share of household budgets. For a typical Norwegian household, annual electricity consumption is around 20 MWh (compared to an average of 3.6 MWh in Britain), while the annual bill would amount to around NOK 14,000 (approx. €1,700) at a price of 250 NOK/MWh.

probably less than 5 per cent. In the remaining segment – households and other industry – temperature-adjusted demand fell by 7 per cent over the November-May period compared to the year before; given an average increase in end-user prices of 30 per cent, corresponding to a price elasticity of 0.23. Both large amounts of electric heating and continuously high prices due to inter-temporal linkages from hydro plants are factors that can increase consumer response and are less pronounced in the rest of Europe. The experience in Norway may be contrasted with that of the other Nordic countries. Although wholesale prices moved more or less in parallel, retail prices were much less affected in these countries. This would seem to be explained by the fact that retail markets differ, particularly in the availability and composition of contracts, but also in market structure and the extent of competition. In Denmark and Finland, where fixed-price contracts dominate, domestic consumers were much less exposed to price increases than in Norway. In Sweden, there is a greater variety of contract types, although the incidence of long-term, fixed-price contracts is higher than in Norway. Moreover, there seems to be less competition among Swedish than among Norwegian retailers, and Swedish retail prices reacted much less than in Norway. As a result, the demand response was much less in these countries than in Norway.

The creation of Nord Pool and the elimination of border tariffs between the Nordic countries were key elements in a strategy aiming at an integrated Nordic market for electricity. The success of this strategy may be measured by the degree of wholesale and retail price equalisation between the different “price areas”.[17] Obviously, an uneconomically large transmission capacity would be required if transmission constraints were to be eliminated, enabling wholesale prices to be equalised across all areas at all times. However, significant and persistent deviations between area prices would imply that the Nordic market consists, in effect, of a set of national or regional electricity markets.

The evidence presented demonstrates that the wholesale market appears to be strongly integrated, with prices in different areas diverging for short periods only. However, as mentioned above, retail market prices reacted very differently across the Nordic countries to the 2002-2003 increase in wholesale prices: while they shot up in Norway, the reaction was much more subdued in Sweden, and in Denmark and Finland retail prices hardly changed at all. There are also considerable differences in the level of retail prices, even when one corrects for differences in taxes and network tariffs. Some of these differences can be explained by differences in regulatory regimes. If one compares Norway and Sweden, where regulations are similar, the retail markets nevertheless seem to perform quite differently. Average retail prices were considerably lower in Norway than Sweden in the early period,

[17] Whenever interconnector capacity constrains power flows, the Nord Pool market is divided into two or more “price areas”. Sweden is always treated as a single price area, and the same applies to Finland. This is because congestion in the national transmission systems is managed by means of so-called counter-trade in these countries. In Denmark, the eastern and western parts of the country are physically separated and hence there are always two price areas – East and West. In Norway, segmentation of the market is part of the handling of transmission constraints and the country may be divided into two to five price areas, depending on the demand-supply configuration.

and the obvious explanation lies in the switching costs. Norway used profiles to determine bills while Sweden required expensive interval meters to switch to a new supplier until she moved to profiling in 1999, after which retail prices moved towards Norwegian levels. Nevertheless, there remain some concerns about price discrimination and market power in the Swedish retail market (as there do in Britain, where retail margins have widened considerably since the domestic franchise ended in 1999).

The Nordic experience suggests that consumers can reduce demand appreciably in response to sustained increases in electricity prices, provided the wholesale prices feed through into retail prices and are not distorted by market power supported by high switching costs. When the reasons for high prices are clear and understood (low reservoir levels) there appears to be no need for regulatory intervention on the disastrous Californian model, although clearly poor market design in California prompted the need for some intervention.

Germany: delayed regulation

Brunekreeft and Twelemann (2005) discuss Germany, the heavyweight laggard of the EU reform process that has finally met the 2003 Directive requirement of a regulator. The new Energy Act entered into force on 13 July 2005, established a regulator, Budesnetzagentur, and implemented regulated third party access using some ex-ante, incentive-based approach to control network charges. Germany provides a fascinating example of the consequence of the failure to properly unbundle and regulate access to the natural monopoly transmission and distribution businesses, for their owners could collect profits in the monopoly segments while engaging in a margin squeeze in the competitive segments, deterring entry and facilitating mergers and increased concentration. This lack of Government concern with market power reached its nadir in 2002 when E.On (one of the two largest vertically integrated electricity companies) merged with Ruhrgas, the overwhelmingly dominant vertically integrated gas company.

Although the Cartel Office prohibited the merger, the Minister of Economic Affairs overruled the Cartel Office (as well as his own advisors in the Monopolies Commission) and approved the merger. Gas is of vital importance as competitively supplied gas offers the prospect of a similar contestable entry price for gas-fired generation throughout Europe, reducing pressures on scarce interconnectors and allowing them to widen the effective market size, improving competition. Gas companies have also been the major entrants into electricity generation and supply competition, offering “dual fuel” deals to households. Removing that competition is therefore doubly damaging. Curiously, the European Commission did not claim any jurisdiction over the merger, despite its potential impact on electricity and gas trade within the EU. This failure to appreciate the special circumstances favouring tacit collusion and the exercise of market power in energy markets has set the process of creating a competitive electricity market back significantly.

Germany has four control areas as a result of vertical integration and earlier consolidation, each with its own balancing market, whose designs Brunekreeft and Twelemann (2005) argue are flawed and manipulable. They hope that once a regulator is in place, these design flaws can be addressed and the markets better integrated. A recurrent theme of the SESSA contributions is that balancing markets are often at the centre of good systems operation and integration, and reforms here might offer the prospect of incremental improvements in market integration that can be addressed largely at a technical and regulatory level. Unbundling is particularly important for allowing this process to work.

The old system of cost-based regulation with high security standards encouraged excessive investment in generation, while the rather generous feed-in tariffs continue to encourage rapid investment in wind energy. Post-liberalisation entry of conventional generation has been disappointing. While this may reflect capacity adequacy and the rather low wholesale prices it is likely to change as about 20 GW of nuclear power is due to be phased out over the next 20 years. There is already a proposal to start building a 2,100 MW lignite-fired thermal station by RWE in late 2005.[18]The authors also note that the way in which the European Emissions Trading System (ETS) will operate in Germany may effectively subsidise entry and facilitate both reserve adequacy and possibly market contestability. Recent forward prices of electricity have responded to the ETS carbon price, although not as fully as in Britain. Thus the forward dark spread for 2006 (the margin between the cost of coal in electricity generation and the value of the electricity produced) had risen from its earlier range around €8/MWh to nearly €19/MWh by mid 2005. Given that the carbon price itself accounts for about €20/MWh for coal, the residual forward dark spread to reward capacity for 2006 delivery was negative. Various interpretations are possible. First, the markets for fuel, electricity and emissions were not yet efficiently integrated. Second, as future allowance allocations are still under negotiation, generation companies chose not to pass through the full opportunity cost of current allowances, as this would provide an argument against future free allocation. Third, generation companies may anticipate that prices of CO_2 allowances may fall because they expect large sellers to enter the market.

[18] Reported statement of RWE's CFO Antonius Voss in Platts *EPD* 13 Apr 2005.

Spain: contractual solutions to market power

Crampes and Fabra (2005) discuss the complicated evolution of the Spanish electricity industry from its formerly highly regulated and cross-subsidised form towards a more market-oriented structure. The Spanish Electricity Market is organised as a sequence of markets: the day-ahead market, several intra-day markets that operate close to real time, and the ancillary services market. The day-ahead market, which concentrates most of the volume of trade, is composed of 24 hourly markets that clear once a day (in contrast to the English Pool where the same bids had to hold for the entire day). On the generation side, electricity producers submit a supply ladder of up to 25 price-quantity pairs per production unit, specifying the minimum price at which they are willing to produce each given quantity. The offers can also include several conditions such as 'minimum income', 'indivisibility', 'load gradient', and 'scheduled shutdown'. The demand side (suppliers and eligible consumers who choose to participate directly in the pool) submit a demand ladder specifying the maximum price at which they are willing to purchase a given amount of electricity. The demand functions can include up to 25 price-quantity pairs.[19]

Once the supply and demand bids have been submitted, the market operator (Compañía Operadora del Mercado de Electricidad, OMEL) constructs a merit order despatch by ordering the supply and demand bids in ascending and descending order, respectively. The despatch and the equilibrium prices are determined through market clearing at the single market-clearing price – the market is thus a uniform-price auction like the English Electricity Pool. Although participating in the Pool is voluntary, capacity payments are only charged and made to participants, and the peculiar and discriminatory method of assignment of these charges and credits has discouraged bilateral contracting outside the Pool until recently, when eligibility has been extended to all consumers. The average capacity payment paid by consumers in 2004 was 4.81 €/MWh. Capacity payments are paid first to units in the so-called "Special Regime" (mainly cogeneration and renewable energy) at 9.015 €/MWh. The residual amount of capacity payments is shared among the remaining production units, proportionally to their capacities (corrected by the unit's availability rate in the current month and subject to some seasonality factors). Capacity payments do not thus differentially reward units available at times of system stress, as with the English VOLL-LOLP scheme.

The industry became more concentrated in the 1990s and by 2001 two firms (Endesa and Iberdrola) generated nearly 80% of output and also had about 80% of retailing. Although this level concentration is being gradually reduced, given this highly concentrated initial structure, left to their own devices the companies would doubtless have exercised considerable market power in the Pool. However, the generators were allocated a variant of contracts for differences – via the payment of Competition Transition Costs (CTCs), partly to recover stranded costs that would not otherwise have been repaid at competitive prices, and partly to ensure that incentives to bid much above competitive prices were restrained. As is

[19] The distribution companies acquire the energy demanded by the consumers subject to regulated tariffs. Hence, they typically act as price takers and submit flat demand schedules at the price cap, 18.03 c€/kWh.

well known, a fully contracted company would bid at marginal cost, but would for that reason typically not choose to be fully contracted.

The CTCs have limited the potentially serious market power of the duopolists in a period of resource scarcity, although providing somewhat perverse asymmetric bidding incentives into the Spanish pool. Iberdrola has a larger market share than its CTC contract share and so benefits from a rise in the spot price, while Endesa has a lower market share than its CTC share and benefits from a fall in the spot price, leading some observers to claim that the outcome was one in which the wholesale price was too low, deterring entry and penalising firms not covered by CTCs.

Spain has rapid electricity demand growth and high prices, so entry and imports would be desirable. For the past 15 years the logical augmentation of the interconnection capacity with lower-priced electricity in France has been successfully opposed, making local generation investment essential. Fortunately, the Spanish gas market structure with a number of entry points for LNG provides a similarly competitive market to that in the UK with its many entry points, and as in Britain, a dash for gas is emerging. For some time the Spanish and Portuguese authorities have been endeavouring to integrate the two systems to create an Iberian electricity market in which all Iberian generation would be able to compete, thus reducing market concentration, particularly in Portugal. To this end more interconnection capacity between the two countries is being built, but progress towards integrating systems operation is proceeding slowly, handicapped in part by the CTCs in both countries and the need to agree on some basic regulatory harmonization.

The Spanish Government has recently reviewed and criticised the CTC system. In November 2004 the Government invited Professor Perez Arriaga to prepare a White Paper on the electricity market, which delivered its report to on 26 July 2005.[20] The White Paper proposes that the industry ministry sets limits on the amount of effective generation capacity any one company may control in the peninsular market. This might be achieved by plant divestiture, virtual power plant auctions (VPPs), following the French and Dutch approach described below, or long-term contracts or – whenever required - some kind of vesting contracts where both price and quantity are set by the regulator. The report notes that CTCs are distorting the market, and argues that the current Spanish system is "at crisis point." The report suggests a number of possible solutions to the stranded cost problem that remove the incentive to distort bidding behaviour and would not impact the wholesale market price. Clearly the solutions and their working out in the market will offer interesting lessons for other concentrated markets (such as the Italian, French and Belgian markets).

Spain (and Portugal) illustrate the problems of liberalising a market after a period in which market concentration was if anything encouraged rather than prevented. Merger proposals, some of them obviously damaging to competition, continue to be made, but there is encouraging evidence that the competition authorities are becoming more aware of the damage that might be done, and some notable cases have recently been blocked.

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[20] The report is published as *Libro Blanco*, dated 30 June 2005 at: http://www2.mityc.es/es-ES/index.htm?cultura=es-ES

The Netherlands: regulatory activism

Van Damme (2005) describes the legally fraught process of liberalising the Dutch electricity market, which narrowly avoided the Government's preferred option of a single national champion generating company. The 1989 Electricity Act had a number of flaws and created perverse incentives, particularly in over-encouraging decentralised, mainly CHP, generation, which lead to over-capacity and inefficiency. The situation was unsustainable, and also incompatible with the Electricity Directive passed in 1996, which required a new Electricity Act that came into effect in 1998. This required legal (not ownership) unbundling of the networks and created a regulator (DTe) as a chamber of the competition authorities (NMa). The tariffs for the networks were now to be set using a price cap (RPI-X) but with the condition that final prices in 2000 were to be set equal to those prevailing in 1996.

Net imports accounted for about 16% of total consumption in 2001 and peak demand was estimated at about 16,000 MW. Import capacity was about 3,350 MW while domestic capacity was 20,400 MW (including some mothballed plant). Access to these interconnectors is through auction, year, month and day ahead, while power is traded in the Amsterdam Power Exchange (APX), including all power imported over the interconnectors (although those buying it abroad can buy it back by bidding at the maximum allowed price). The APX market-clearing price is found as the intersection of the offer and bid ladders for each hour and these schedules can be viewed on the APX web site the day ahead. Wholesale prices are higher than in neighbouring countries, and despite apparently strong interconnections that were auctioned long-term and day ahead, constraints have supported high interconnector prices.

There are four main generating companies (Electrabel, also the monopolist in neighbouring Belgium, with 33% of central capacity, Reliant, with 26%, Essent with 23% and E.On with 12%) connect to the high-tension grid, while about 30% of total capacity is decentralised (i.e. connected to the lower tension grids). These four companies are restricted in the amount of interconnection capacity they could contract to 200 MW each, and the NMa reported that the resulting HHI in 2002 was 1754, just below the 1800 mark taken to indicate a concentrated market in which further mergers may be problematic.

The four original generation companies had tried to merge earlier but could not agree, and considerable concentration had taken place in distribution companies (which was logical, given their often small size). In 2003, Reliant, a US company that had entered in 1999, decided to exit, and wished to sell to Nuon, which would then have created the largest generation company, raising the HHI to 1974. In contrast to Germany, the proposed Nuon-Reliant generator merger was intelligently analysed with competent economic modelling (as described in van Damme, 2005), and the sensible remedy of a virtual power plant (VPP) auction for 900 MW was proposed. The intention was to offer 90 blocks of 10 MW each offered at the marginal cost of the most recent plant (the Intergen CCGT). These VPPs could then be bid into the APX if required and would receive the market clearing price (if above the offer price, which might be this marginal cost or VPP strike price). The holders of the VPPs would thus earn a profit and would be willing to pay a premium into the VPP auction for the right to this flow of profits. The underlying plant(s) would be operated by the merged company but they would not enjoy any operating profits.

The plan was to sell VPPs for five years in the first instance, but this was contested in the courts and reduced to one year at a time. One of the issues was whether an annually repeated VPP auction would encourage the seller to bid up APX prices to make the auction price higher shortly before each auction, and if so this temptation would be reduced by infrequent auctions for longer periods. Action design is a technical matter not always well-understood by courts, but if VPPs are to be used as a method of mitigating market power this question is an important one to address (as is the choice between discriminatory and uniform price auctions in other markets).

In contrast to this sophisticated merger analysis, the price caps imposed in 1999, which had company-specific X-factors based on a benchmark analysis, were appealed to the courts, who narrowly and perversely interpreted the 1998 Electricity Law as requiring a single X-factor to apply to all companies. The Act has subsequently been redrafted to avoid this perversity, although using the courts rather than a more professionally competent dispute resolution authority (a role played by the Competition Commission in Britain) appears to be unsatisfactory.

The Act also had to be modified to enable the regulator to collect the kind of information needed for proper wholesale market surveillance, and even now there are difficulties in that the generation companies do not have the kind of licences that could contain conditions enabling the regulator to request market-relevant information. The Transmission System Operator, TenneT, clearly has access to much real time data, but appears not to have the authority to release commercially sensitive data to DTe. The Competition Authority could request such information if there were evidence of market abuse, but collecting such evidence without good reason is difficult.

Another major market design issue facing the Netherlands and neighbouring countries is how best to achieve closer market integration. This process would start with Belgium, but with the object of eventually making France, Benelux and Germany comparable to Nord Pool as far as pricing, dispatch and balancing services are concerned, with market splitting when constraints bind. Simulations suggest that the cross-border ownership (Electrabel in Belgium and the Netherlands, E.On and RWE spanning the Dutch-German border, in both cases owning transmission and interconnection) makes market integration more problematic. This again highlights the importance of acquisition and mergers that are viewed too narrowly in national terms, and over which the European Commission has taken too relaxed an approach.

Most central generation in the Netherlands is gas-fired, predominantly large gas-fired Steam and Gas or Combi plants, some of them combined heat and power (CHP) plants providing heat for district heating. Pricing gas therefore has a direct impact on the price of electricity, and has since liberalisation made the Netherlands more expensive than her neighbours. The gas market is concentrated, but efficient restructuring is impeded by ownership interests, not least of the Dutch Government. The gains from more complete gas liberalisation, not just for the Netherlands but across Europe, could be significant.

Finally, DTe and the Government are concerned about security of supply and whether a liberalised energy-only market (such as the APX) can support adequate investment or whether capacity payments are needed. As in other countries, this issue remains unresolved.[21]

France: reform retaining a state monopoly

Finally, Glachant and Finon examine the curious case of French electricity reform "in which the state-owned monopoly was not privatised, demolished, or dismantled." They consider the extent to which the competitive fringe (mainly of importers) can restrain the 800lb gorilla, EdF. Part of the problem of introducing effective competition in France is that she has a surplus of very low variable cost nuclear power, and little economic motive for new investment for the next decade. Whether a "privatised" EdF will exercise its undoubted muscles and induce entry, and whether the state-owned gas company GdF will provide effective retail competition and perhaps gas-fired generation competition or roll over and become part of EdF, remain questions for the future to answer. It may be that the French concept of privatisation (majority state-owned) allows EdF to continue its public service obligation to keep wholesale prices low (while charging domestic customers economically sensible Ramsey-Boiteux prices). This would maintain the status quo, but the rocky state of French public finances may make further privatisation and/or the exercise of market power to generate handsome dividends irresistible.

The Lessons learned

Competition requires that entrants can deliver power to consumers on the same terms as incumbents, and that requires non-discriminatory access to transmission and distribution, unbundled cost-based tariffs for their use, and no informational advantages to the incumbent. Vertically integrated transmission and generation companies can exploit informational advantages, discriminate in the provision of access, balancing and other ancillary services, and cross-subsidise competitive activities by inflating monopoly costs. British, US and German experiences demonstrate that vertical integration is a major impediment to efficient market access and also to inter-TSO trade.

Unbundling and concentration

Full ownership unbundling is the prize to strive for, and pressure from regulators and competition authorities should make this the least undesirable option for incumbents. If ownership unbundling cannot be negotiated, then the second-best alternative is an independent system operator (ISO), although it is harder to incentivise ISOs than TSOs with assets to bear the profit risk associated with any incentive regime. This seems to be more likely than the final option of regulatory and judicial pressure on vertically integrated TSOs to implement access and balancing arrangements that minimise consumer costs. If the ISO option is adopted, incentive regulation for transmission and distribution, ideally based on

[21] See Roques et al (2005) for a discussion of security of supply.

benchmarks, is a demonstrated method of improving efficiency and reducing consumer costs, and, if well-designed, without prejudicing investment and security.

Effective competition requires that individual generating companies are rarely pivotal (that is, essential for balancing supply and demand), which can be achieved by a combination of adequate spare capacity, sufficiently numerous generators or import capacity, and a competitive contract market, supported by free entry and non-discriminatory access to transmission and balancing services. Current market structures are often too concentrated to deliver competitive outcomes without close regulation, state ownership, or imposed contracts or equivalent schemes (such as the Spanish CTCs). Outside Nordel, interconnection is typically inadequate to address country-level concentration, and absent these conditions for competition, the choice of market design is unlikely to adequately mitigate market power, although some designs may facilitate collusion more than others.

Wholesale market design

The question of market design has a number of dimensions. Clearly it should be tailored to the circumstances of each country (ownership structures, fuel sources, and institutional/legal endowments and capabilities), but it should also facilitate a move towards a single EU-wide electricity market. The EU has been able to make remarkable progress in creating the preconditions for a liberalised and integrated electricity market through a sequence of Directives and Regulations, but these can only reflect current political consensus. Whereas in the US FERC as the federal energy regulator can encourage and cajole states to adopt a standard market design (SMD), Europe lacks such a regulator and relies on consensus and comitology for progress beyond the rather sparse details of the Directives. Progress on both sides of the Atlantic has been slow – states' rights have similar salience to national subsidiarity. Creating markets which undermine impediments to market integration, perhaps starting with the regional integration of power exchanges (PXs), leading on to agreements among Transmission System Operators (TSOs) to integrate balancing markets to increase liquidity, might be more effective than political consensus-building. Liquidity and integrated balancing markets are both impeded by vertical integration and poor information sharing between TSOs.

Among wholesale market designs, marginal single-priced pools have advantages in providing a reference price facilitating contracts and hence entry, and allowing scarcity-responsive capacity payments (as in the former English Pool), but their transparency and repeated auction structure facilitate collusion if there are fewer than four or five comparable generation companies. Problems of gaming and collusion fall as the number of participants increases and the length of time for which bids must hold increases (so that bidding separately for each hour as in Spain or APX is likely to be inferior to bids that must hold for 24 hours, as in the former English Pool).[22] Power exchanges typically only trade 5-15% of

[22] APX adopted the Spanish software that allows separate bids for each hour (and both power exchanges publish the aggregate supply and demand schedules for each hour). Bids are firm but in Spain they can be adjusted with new bids in the six intra-daily markets at four-hourly intervals.

consumption in the prompt market, while forward bilateral contracts are either illiquid (if profiled) or inflexible (if restricted to base and peak power). In such cases liquid balancing markets are critical to competitive entry and supply. They may also be essential for security of supply in concentrated markets where the dominant incumbent is inhibited from investing (and further foreclosing the market) and entrants are deterred by the risks of illiquid, volatile and unpredictable balancing markets or mechanisms.

Balancing markets and cross-border trade

Balancing markets are therefore of central importance to promoting the European dream of market integration that delivers sustainable competition, and offer the prospect of breaking the log-jam of political consensus-building required to deliver mandatory Directives. While that process seems to have worked quite well for telecommunications with the Communications Directives emphasising regulation to address Significant Market Power, telecoms liberalisation is both older and more amenable to *ex post* regulation than electricity. Optimists believe that the process of introducing new Directives and Regulations has accelerated and will solve these problems; realists are sceptical.

Agreement among TSOs (encouraged, supported and perhaps pressured by their local regulators) to exchange appropriate information and delegate balancing dispatch offers the prospect of creating liquidity first in the balancing or real-time market. Integrating balancing markets will reduce the required balancing volume, as some volatility cancels out, and will increase the number of competitors providing services in each market, thereby reducing balancing costs and encouraging trust in the balancing market. It may be that integrating balancing markets need to await the development of a well-functioning European day-ahead energy market, although progress is presumably more likely at a regional level first, again possibly following the improvement of day-ahead market integration. Again, vertically integrated TSOs might be reluctant to integrate balancing markets that allow more entry into their own wholesale markets and reduce generator or supply profits.

Electricity markets are likely to be more conducive to tacit coordination than most other markets of comparable concentration, while non-storability and a low elasticity of demand amplifies market power, requiring a more informed approach to competitive analysis by regulators and competition authorities. Creating competitive gas markets, with gas-on-gas competition through liquid spot and balancing markets (as in Britain) offers the prospect of equilibrating the effective cost of the major electricity fuel across Europe, and hence reducing cross-border generation cost differences, reducing the need to trade and hence freeing up more interconnection for importing competition into otherwise concentrated markets (as in Nordel).

Efficient trade requires efficient pricing and allocation of transmission, best achieved by nodal pricing on the PJM standard market design. The next best solution is market coupling. Local power exchanges would send their aggregate bid-offer curves to an international clearing stage, which would allocate transmission capacity between countries in a procedure similar to the synchronised auctions currently proposed by the European system operators. Local power exchanges would then schedule the corresponding international flows and clear the local markets. This approach allows for netting and may work reasonably well if transmission within countries is adequate. Zones can be subdivided further if internal congestion levels increase. Again, access to full information is key to improving allocation and increasing available capacity, but requires trust that is best underlined by ownership unbundling or a regional ISO structure. Once that has been achieved, it might be sensible to revisit the appropriateness of the current technical transmission standards to see whether they are suitable for a decentralised and liberalised market.

There are two arguments brought forward against this approach. The first is the likely reluctance of local PXs to create and join an international clearing house, which would largely undermine their own function (and similar progress for European stock exchanges has been woefully slow). The second problem is the existence of zones with adequate uncongested internal transmission. The Scandinavian example shows that a national power exchange can operate multiple internal zones, and liquidity in the exchange was apparently not adversely affected by subdividing the market. Liquid longer-term contracting may require the TSOs to issue financial transmission contracts as in PJM and other Northeastern US markets.

There are also concerns about the problem of generation and transmission adequacy. Generation margins are getting tight in several European systems and there is widespread doubt that this issue could be left to energy-only markets, although this is still an open issue. Any move away from energy-only markets requires a choice between the alternative mechanisms that could be used, such as the LOLP scheme (which has some attractions but also critics), capacity payments, capacity obligations, etc. The CEER has issued a recent document on transmission investment, where the need to guarantee an adequate return on new investment (best achieved by running public auctions to build new lines, proposed by TSOs and authorised if needed by regulators) and full recovery via transmission tariffs was emphasized. The experience in the U.S. is that unless actively encouraged, adequate inter-TSO transmission investment is most unlikely, while building any transmission in the teeth of local environmental objections is difficult, as the failure to complete the France-Spain interconnector demonstrates.

A disagreeable implication of this is that market integration is likely to stall at the regional level, so that each region will remain largely isolated from the other regions. This might not matter too much if countries evolve similar fuel prices and make similar technology choices, as that will equilibrate electricity prices, arguably at lower financial and political cost than massive investments in interconnectors.

Sustainability and emissions trading

Finally, sustainability in the context of electricity markets has a further connotation in that the full environmental costs should be taken into account in investment and consumption decisions, so that the industry can evolve towards a low carbon future that does not prejudice the life chances of subsequent generations. This is recognised by the EU acceptance of the Kyoto targets and an EU commitment to market solutions to reflect the cost of greenhouse gas emissions. As the output of wind energy (the dominant source of renewable generation) can only be accurately predicted a few hours before dispatch, it is important that market design does not create artificial barriers for such flexibility. This operational flexibility is of particular importance for transmission and it constitutes a new challenge in transmission network operation and design. An adequate design of balancing markets is crucial here. Market design and market structure should be used to minimise the exercise of market power in short-term (and ancillary service) markets which increase the costs of intermittent generation. Efficient use of international transmission capacity will allow international balancing and should further reduce intermittency costs.

The aim of the European Emissions Trading Scheme (ETS) is to equalise the price of carbon across the EU. If it is combined with a form of allocation that does not distort investment and operating decisions, the ETS should lead to the same cost increase for marginal electricity generation by each fuel in each country, and hence would not distort dispatch, trade or investment.

The main concerns are to do with distortions arising from the system of allocating emission allowances. If emission allowances are contingent on continuing plant operation, they will discourage replacing inefficient high emissions plant by more efficient low emission plant. If future allowances are allocated on the basis of generation (kWh) in some countries (rather than capacity, kW) they could distort the marginal cost of operation in different countries and hence trade. If allowances are allocated by type of plant they could also prevent the desired change in the merit order towards lower carbon-intensive plant. Nevertheless, the ETS represents a considerable advance on more political and quota-based alternatives.

The future

Together the authors who contributed to this work package have used their country examples to raise almost all the main issues that need to be addressed when restructuring electricity industries to open up their markets. The next stage in Europe will involve full liberalisation of the accession countries, reforms to area-wide systems operation, transmission access and pricing, and the evolution of investment under the ETS. No doubt the electricity supply industry will continue to pose fascinating problems for energy economists to study and on which to offer guidance to the various regulatory authorities.

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Acronyms

APX Amsterdam Power Exchange
BETTA British Electricity Trading Arrangements
CCGT Combined cycle gas turbine
CEER Council of European Electricity Regulators
CEGB Central Electricity Generation Board
CHP Combined heat and power
CTC Competition Transition Contracts
DTe Dutch electricity regulator
EC European Commission
ESI electricity supply industry
ETS Emission Trading System (for trading carbon dioxide)
EU-15 The original 15 member states of the European Union
FERC Federal Energy Regulatory Commission
HHI Herfindahl-Hirschman Index, = sum of squared percentage market shares
ISO Independent System Operator
LMP Locational Marginal Pricing
LOLP Loss of Load Probability
LSE Load Serving Entity (i.e. supply company)
NETA New Electricity Trading Arrangements
NGC National Grid Company, Britain's TSO
NMa Dutch competition authority
NOK Norwegian Krone
OTC Over the counter
PJM **P**ennsylvania, New **J**ersey and **M**aryland
SMD Standard Market Design (SMD)
SMP System Marginal Price
SO System Operator
TSO Transmission System Operator
UCTE Union for the Co-ordination of Transmission of Electricity
VOLL Value of Lost Load
VPP Virtual Power Plant