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Deregulation and Regulation in the European Power Market

By Martin Kreuzberg* and Christoph Riechmann**

Summary

Transparent network access conditions and a transparent organised wholesale market (Power Exchange) are necessary but by no means sufficient conditions for a competitive European Electricity Market. Market structure — in particular high concentration among generators — and technical restraints on cross border trade can preclude competitive market outcomes. Indeed, we find empirical evidence of rather high wholesale prices in the more concentrated British and Spanish electricity markets. On the other hand we observe prices at the level of short run system marginal cost in the Western European power market. This situation in Western Europe will not be sustained. Either a decrease in reserve capacities over time or an increase in generator concentration through mergers will lead to higher wholesale prices in Western Europe. Competition authorities are in a dilemma. They will not want to preclude mergers where benefits of cost savings prevail and merged companies are not in a position to abuse market power. However, they must preclude mergers where (regional) markets are in danger of becoming uncompetitive. In particular, mergers of major players that allegedly counterbalance the dominant position of Electricité de France (EdF) do not enhance the competitiveness of the market, but rather aggravate problems. Empirical findings are compared to results derived by the large scale electricity market simulation model EUDIS. This comparison supports the theoretical reasoning we make.

Introduction

With the enactment of the European Electricity Directive (96/92/EC) EU-member countries have been obliged to implement at least a gradual or full opening of their electricity markets into national legislation. Previously, market entry had been hindered by statutory (legal) or effective monopolies. The deregulation debate had gained momentum with liberalisation experiences in Great Britain (from 1990), Norway (from 1991), Sweden (1996) and Finland (1996) as well as similar overseas experiences (New Zealand from 1993, Victoria/Australia from 1993).

Main provisions of the Electricity Directive include:

- third party access to the networks and therefore wholesale and retail competition;
- organisational unbundling of electricity transmission at the extra high voltage level and other activities;
- accounting separation of generation, distribution/retail supply and non-electricity activities.

Member countries (with few exceptions) were obliged to implement the Directive by February 1998. Most countries have opted for a system of regulated third party access (TPA), while Germany has left the development of network access rules to negotiations among network operators and large industrial consumers under a regime known as negotiated TPA.¹ France failed to implement the Directive in time and discussions were still held on an appropriate competition regime in October 1999.

Although most EU member countries meanwhile comply with the Electricity Directive several governments

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¹ The Electricity Directive allows for a third regime, the so called Single Buyer (SB). In economic effect the SB model closely resembles the regulated TPA option so that we do not distinguish these in the following.

have used the political principle of national subsidiarity to soften the intensity of competition. Countries like Italy, Spain, the Netherlands or Austria have limited retail competition to the largest industrial consumers. Countries like Austria, Germany and Belgium have allowed incumbent firms to maintain vertical ownership integration between generation and transmission which may create opportunities for discrimination of network access (e.g. as regards implicit network charges or access priorities in situations of grid congestion). To prevent incentives of incumbents to foreclose respective national markets or to disfavour competitors in domestic markets a number of countries (England and Wales, Norway, Sweden, Finland, Spain, the Netherlands) have rigorously separated generation and transmission functions.²

So called reciprocity clauses are aimed at ensuring that countries must only allow competitive entry of players in whose home country competition is already developed to a comparable degree. The reciprocity clause has turned out to be rather ineffective as the source of electrical power is hard to trace. A German retailer may be buying from Switzerland³ without indicating that the generation back-up actually comes from France.

While in the following we find some indications of an integrated European wholesale and generation market, retail competition has to date largely remained nationalised. Cases of competitive supplies to retail customers by foreign entrants have to date been anecdotal. Networks exhibit features of natural monopolies and have been subjected to regulatory oversight at the national level. International interrelations emerge as countries learn from their neighbours' regulatory regimes. Control over the transmission networks additionally bears the complication that a level playing field wholesale and generation market would require harmonised European wide commercial rules for the use of transmission networks. However, we currently observe a tendency of national regulators/authorities

- to allow that transmission charges are levied onto retail customers (or their retail suppliers) which relieves generators of transmission charges and fosters their international competitive position
- and in addition to allow transmission charge mark-ups in cases of cross-border transactions to further disfavour competition from foreign generators.

We proceed by outlining institutional arrangements in the European Power Market (section 2). We outline the relationship of market structures and likely market conduct in the European Power Market (section 3) and highlight potential dangers of increasing market concentration. We then outline a model that gives an appropriate replication of the European Power Market under current market structures (section 4).

Institutional arrangements — Network rules and power exchanges

Power exchanges

Experiences with organised national electricity wholesale markets in England and Wales (Electricity Pool since 1990) and in Norway (originally formed 1990, in 1996 re-named to Nordpool) stand at the beginning of the debate over a rigorous deregulation of electricity markets. These power exchanges have been known as Pools that arrange bidding processes for day-ahead physical power delivery for standardised intervals (30 min in England and Wales, 1 hour for Nordpool) in the high voltage transportation network. The impact of the British experience is rather indirect. Market rules in the original Pool are today seen as too tight; the Pool was mandatory for most generators and complex bidding rules had to be abided by. Reform debate is under way and likely to take effect early in the year 2001. The British Pool is also remote in technical terms. Interconnection capacity with the continent is limited to 2000 MW (which corresponds to less than 5% of maximum demand in the British power system) and price interaction with Continental Europe is currently insignificant. In contrast Nordpool was set up as a commercial organisation without a monopoly over market making. After integration with Sweden (1996) and Finland (1998) Nordpool forms the first organised international power market and attracts some 30% of physical trading volume in Scandinavia. Due to stronger interconnection capacities of Scandinavia with Continental Europe parallel movements in wholesale prices can already be observed. Nordpool has meanwhile expanded its activities to Denmark and is seeking to establish East Germany as a related market place through its project of a "Leipzig Power Exchange" (LPX).

In 1998 another Power Exchange was opened in Spain. Market rules are similarly restrictive as in England and Wales. Since all major generators have a Pool trading obligation the Spanish Pool has a guaranteed market volume. In March 1999 the Amsterdam Power Exchange (APX) took up operation as a purely commercial organisation. Trading in the APX is currently limited to negligible levels as the Dutch transmission system operator (TenneT) was only willing to reserve 250 MW of network import capacity for Pool trading.⁴

² Hoster, Riechmann and Schulz (1997) give an overview of potential obstacles to a fully integrated European power market.

³ Switzerland is not covered by the reciprocity clause. As a non-EU member the more liberal international WTO rules apply.

⁴ According to announcements by the Dutch Electricity Regulator (DTe) the cross border capacity for Pool trading will be increased to 900 MW in 2000.

Price indicators for defined regions have added to information transparency in the European wholesale market. The Swiss Electricity Price Index (SWEP) has been quoted since 1998 for peak power at the reference point of Laufenburg on the Swiss-German border. The Central European Electricity Price Index (CEPI) has been quoted for interconnections of the company PreussenElektra in Germany with neighbouring transmission system operators for peak-load and base-load periods. Intentions are to establish a European Energy Exchange (EEX) in Frankfurt for forward (initially for week or month ahead trading) and according to recent announcements also for spot contracts. This project is effectively competing with the LPX. It is unlikely that a number of power exchanges will survive in Central Europe if international borders do not constitute limitations to electricity trade. On the other hand a further power exchange could well be established in Italy which is somewhat remote from the Central European Power market in technical terms.

Network access rules

Restraints to generation wholesale competition may be technical or commercial (ie due to market power exerted by vertically integrated network monopolists). Technical limitations e.g. on available international electricity transfer capacity (also referred to as interconnection capacity) may effectively prevent international power trade and in consequence promote market power and abusive behaviour of dominant players in national markets as will be outlined below.

Even where significant interconnection capacities exist (as e.g. for a region comprising France, Germany, Austria and Switzerland) international trade is to date restrained by a lack of practical commercial international interconnection arrangements. Market participants must rely on the co-operation of European Transmission System Operators who are in many cases vertically integrated with generation businesses that are (potentially) exposed to competition. That is to say that intensive international trade may be taking place between these integrated players (and it has already taken places even in the era of national monopolies as can be seen in electricity statistics of im- and exports) but smaller players without physical international interconnections (like regional or municipal companies) and newcomers such as independent power producers (IPPs) and independent traders may be excluded from the market or may only be able to gain access after paying a significant premium.

The international debate over appropriate commercial transmission arrangements for cross-border trade still far from being concluded although it has advanced considerably over recent years. For their national market most industry representatives have accepted the principle of

generalised grid access for points of connection and of exit (where network access implies access to the market) in contrast to a transaction based point-to-point regime (which requires commercial arrangements to be matched exactly by network access contracts) previously favoured by incumbents.⁵ For cross border transaction the representatives of Germany, France, Spain, and the Netherlands among others demand that network charges contain significant elements of a transaction based approach (clear-cut proposals have not yet emerged in the public). In essence the debate circles around the question whether power trade between Spain and Scandinavia could be faced with the same or even a lower transmission charge than trade e.g. between Germany and France. There are two major concerns over transaction based network access regimes that usually imply distance related fees or at least a price mark-up on international transactions: adverse steering effects and an uneconomic allocation of congestion cost:

- Steering effects: In economic terms generalised access arrangements are efficient if for instance international net power flows were directed from North to South. In that case the trade from the Mediterranean area to Northern Europe would help relieve grid congestion and should get more favourable network access conditions than a trade that adds to a line that is already congested. This implies that a transaction based regime may give correct signals for network usage in a large number of cases but is likely to give wrong signals in a significant number of cases. This was shown by Rolf, Fritz and Haubrich (1999) and Haubrich, Fritz and Vennegeerts (1999) in electrical engineering simulations for Germany and Europe respectively: international commercial transactions in Europe relieve network constraints in almost as many cases as they add to such constraints. Whether certain transactions burden or relieve the network does not depend on the distance between the transacting parties, but on the system capacity and system load situations in the region where the generator and the consumers are located. Consequently these technical conditions are accounted for under generalised network access regimes for example with regionalised charges for network entry and exit.
- Allocation of congestion cost: under transaction based approach whoever seeks network access last is burdened with the cost of network congestion (di-

⁵ This perception is also implied in the communiqué on the new Association Agreement (*Verbändevereinbarung*) between the German electricity industry and representatives of large energy consumers (BDI/VIK/VDEW (1999): *Gemeinsames Kommuniqué zu den Eckpunkten einer weiterentwickelten Verbändevereinbarung über Kriterien zur Bestimmung von Netznutzungsentgelten für elektrische Energie*, Bonn, 28. September 1999).

rectly by having to pay a significant premium or indirectly by being denied the execution of a transaction). As outlined above, network congestion is a system feature and not result of individual action and so congestion cost should be shared by all network users who contribute to them. This is to make sure, that congestion is reduced, if possible, by actions of those players, who can do so at lowest costs, a first (and second) order condition for economic efficiency. This is not to say that the primary network pricing regime must reflect this principle — however, the network pricing regime must be so designed that the cost of network utilisation are ultimately reflected to all network users. Economic efficiency and transparency could e.g. also be achieved by organising primary and secondary trading of transmission rights on congested networks.

Norway, Sweden and Finland provide an example of how such an international network pricing regime could work. In principle, agents pay either entry or exit charges depending on whether they are generator or suppliers/consumers. These charges are determined by the respective national system operators (in Finland generators are exempted from network charges). In principle there are no additional charges for cross-border transactions unless constraints on interconnectors arise. In this case all generators in the area of generation surplus and all consumers/suppliers in the region of load surplus pay a premium on network charges while conversely generators in the load surplus area and consumers in the generation surplus may receive a bonus. Similar pricing rules apply within the national systems in Sweden and Norway (short term nodal prices in Norway, regionally differentiated entry and exit charges in Sweden). This implies that network access on international transactions may in some cases be cheaper than for national transactions. Political incentives to come to such efficient arrangements were quite strong in Scandinavia as national markets are highly concentrated and (the potential for) international trade was seen as a means to break up market power of national incumbents.

Structures, conduct and performance in the European Power Market

The problem of market power in electricity generation

While the regulatory debate has until recently been focused on the choice of the liberalisation model (at the wholesale level: mandatory Pool versus third party access/wheeling with an option for a voluntary Pool) recent discussion also devoted some attention to the relevance of horizontal market structures at the generation level for the competitive process.

The pivotal problem is that generation capacities within one region are typically limited and cannot easily be expanded within a short period. Advanced combined cycle gas turbines (CCGT), for instance, ideally require a planning/authorisation and gestation period of some 18 months and larger conventional plants typically require even more time until they can start to operate (in the case of nuclear plants this may take up to a decade depending on national planning regulations). In particular, incumbent generators with a high capacity share may expect to have some share of the market “reserved” for them; in extreme cases large generators can estimate a market share that cannot technically be supplied by any other supplier due to limited generation capacities of these competitors (and also due to limited interconnection capacities with other regions).

The problem has initially been analysed theoretically by Bolle (1992) and by von der Fehr and Harbord (1993); for the case of the insular UK system and for short-run (day-ahead) competition by Green and Newbery (1992); Green (1996a) as well as by Wolak and Patrick (1996), with long-term elements, however, entering through a financial contracts market that may commit generators to certain price/quantity offers in short-run competition. More recently research was extended to different timing structures of the competitive process (day ahead markets in conjunction with physical and financial contracts markets) by Green (1996b), Newbery (1998) and Riechmann (1999) and to behaviour under potential competition through transmission interconnections to neighbouring states/countries by Borenstein et al. (1996) as well as by Borenstein and Bushnell (1997).

The essence of this research is that in situations with high market concentration, especially among medium load (coal) generators there is potential for near (Cournot) oligopolistic bidding behaviour (and in addition a potential for tacit collusion) that could each imply pricing well above marginal cost. Generators may not only be able to recover their fixed cost through such mark-ups, but also to achieve super-normal profits. In the case of limited over-capacity such allocative inefficiencies are likely to increase in the degree of market power/market shares of dominant firms — as the size of their “reserved” market share increases. Therefore, we expect a strong relationship between market structure and likely market performance, that is pricing behaviour.

We now briefly outline in how far electric power exchanges and limited international interconnection capacities may impact on the market power problems.

— Electric Power Exchanges do not automatically restrain market power of incumbent generators. However, they can be regarded as institutions that promote market transparency by providing credible price indications. Price transparency may in turn allow

regulatory or cartel authorities to detect excessive prices — i.e. uncompetitive market performance.

- Limited interconnection capacities do not automatically restrain competition as can be seen from the Scandinavian experience, where market concentration within national boundaries is high even after allowing for imports according to available transmission capacities. As commercial transactions in opposite direction technically cancel each other out in electricity networks, trading potential is far greater than that indicated by available transmission capacity. A pre-requisite for such lively trading is obviously a transparent opening of all national markets.

Measuring market power in the generation market

To capture the market structure at the generation level at the outset of competition we use concentration ratios (CR X) and the composite Herfindahl-Index (HI)⁶ for generation capacities (MW) to analyse market concentration.⁷

We focus on concentration of installed capacity (MW) (as proxy for available capacity) since it is capacity constraints that potentially constitute market power. We limit our attention to the public supply system (i.e., for comparability of data we ignore industrial auto-production on which little consistent information is available across countries).⁸ We also include interconnection capacities to neighbouring regions/countries to account for potential competition through these wires.⁹ We further analyse allowed mergers upon competitive opening. All plant capacity information is based on 1997 data. In case of divestiture or merger, registered 1997 capacities are redistributed among generators to reflect the (January) 1998 ownership structure (unless indicated otherwise). Concentration indices have some relevance in international antitrust policy. In American antitrust policy, for example, values for the Herfindahl-Index have the following interpretations:

- $HI < 0.10$: low concentration,
- $0.10 \leq HI < 0.18$: moderate concentration,
- $0.18 \leq HI$: high concentration.

in German antitrust policy, for example, firms are considered as dominant if (§ 19(3) GWB)¹⁰

- they alone (CR1) hold a market share of one third or
- if together with one or two other firms (CR2 and CR3 respectively) they hold a share of half or more of the market,
- or if up to 5 firms have a joint market share of two thirds or above.

We note that — given the characteristics of electricity generation as a largely capacity constrained industry — legal interpretations of simple concentration indices (CR or Herfindahl) may well understate the economic severity of market power problems. The UK experience, for instance, shows that serious problems of market power may arise even in situations where concentration indices suggest moderate to low concentration.¹¹

Empirical analysis of market concentration

When considering the electricity generation in Central Europe as one market place, we formally derive an index of low or moderate concentration, even when taking into account that Electricité de France (EdF) accounts for almost twice as much generation capacity (103 GW) as the

⁶ CR X gives the market share of the X largest firms. It is therefore bounded between 0 and 1; a large CR X value gives evidence for high concentration. HI is calculated as the sum of squared market shares of the individual companies. HI is therefore bounded between 1 and $1/N$ where N is the number of firms in the industry; a large index value gives evidence for high concentration.

⁷ We note several shortcomings of this approach, especially when we proceed to an international comparison, e.g.: (1) In Pool markets, in particular, market concentration among medium load (coal) producers is of great importance for market results (bid and strike prices). It is, therefore, of relevance, how medium load plants are distributed among generators. Bidding behaviour will vary between systems dominated by thermal and by hydro generation technologies. Hydro systems are typically energy (i.e. water) restrained so that capacity is not available continuously, while thermal generation capacity can be regarded as firm capacity. Hydro and thermal capacities are therefore not directly comparable. Market concentrations can exist in sub-regions as result of transmission constraints within a region. These sub-regional concentrations are not captured by concentration indices. Market power, depends not only on market shares (in terms of installed capacity), but also on the width of reserve margins (i.e. a generator with a high share of capacity may not be able to exert market power, when the generation reserve of other generators is high in absolute terms).

⁸ Note that in the excluded segment of industrial auto-production competitive forces (e.g. through market entry of independent power producers or IPPs) have prevailed in most countries even before legal reform.

⁹ In calculating the indices we treat the interconnection with each region as one competitor, although we note that there may be more than one generator behind an interconnection. When calculating CR X the interconnection capacity merely reduces the market shares of incumbent/domestic generators (interconnector capacities are not ranked among the X largest generators). When calculating the HI the interconnector capacity also reduces the individual market shares of incumbent/domestic generators, but as a composite index the interconnection capacities also positively enter into the index value.

¹⁰ In US and German antitrust policy concentration ratios have a relevance in evaluating merger cases. In Germany they also inform authorities about the firms that can potentially be exposed to a control of behaviour (*Verhaltensaufsicht*).

¹¹ See also Bunn, Day and Vlahos (1999) and Riechmann (1999), FN 173. Also refer to FN7.

next largest generator ENEL from Italy (56 GW). The next largest generators include RWE Energie of Germany, Endesa of Spain and Vattenfall of Sweden (Figure 1, Figure 2).

Market concentration (measured by the Herfindahl-Index) nominally increases if certain regions are excluded from our calculations. In Figure 2 starting from EU15 + Norway and Switzerland we gradually exclude (1) Ireland and Greece which are disconnected from Central Europe; (2) Portugal and Spain that only have a weak interconnection with France; (3) the UK that has a 2,000 MW interconnection with France which is in practice only used for imports; (4) Italy that uses interconnections extensively for imports; (5) Norway, Sweden and Finland that have limited interconnections with Central Europe. With this market definition that excludes Italy, the UK, the Iberian peninsula and Scandinavia market concentration reaches moderate levels in Central Europe. We also see

that high market concentration is largely attributable to EdF. If France is excluded from calculations, market concentration in Central Europe — comprising Germany, Switzerland, Austria, Belgium, Netherlands, Denmark — becomes low (HI: 0.066). Concentration in a Western European market would increase if prospective mergers between PreussenElektra and Bayernwerk and RWE and VEW in the German electricity industry went ahead.

This helps to illustrate two interesting points:

- market concentration in the Western European market (excluding France) would not rise to nominally critical levels after mergers of PreussenElektra/Bayernwerk and RWE/VEW. A nominally critical level would be reached if VEAG was to merge with either RWE/VEW or PreussenElektra/Bayernwerk,
- nominal market concentration in the Western European market increases to moderate levels if

Figure 1

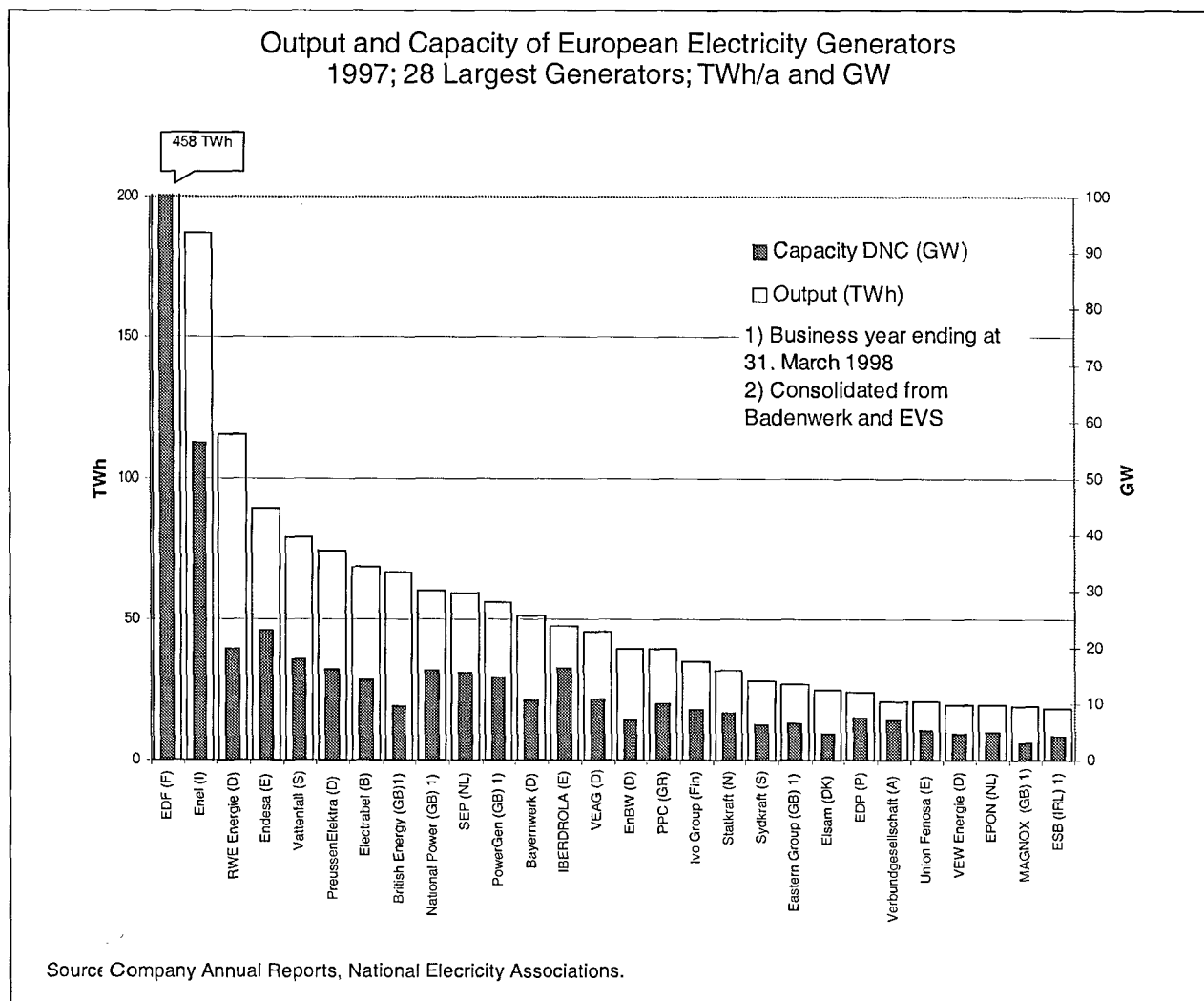
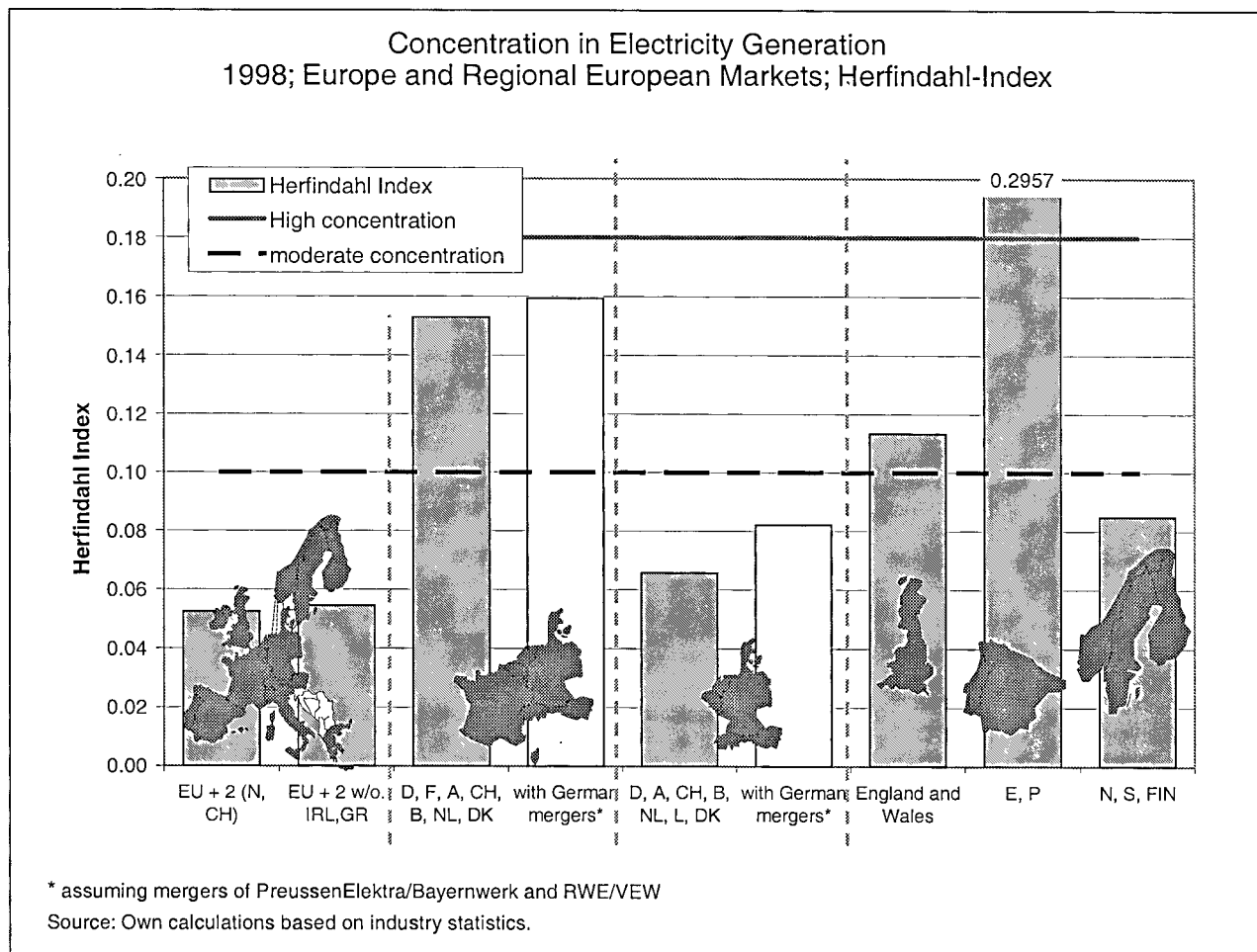


Figure 2



France is included in the analysis. Concentration would reach a nominal level beyond that at which abuse of market power was perceived in England and Wales.

The second point is, of course, apparent even before any numerical analysis. The point is nonetheless interesting as PreussenElektra and Bayernwerk justify their merger partly with an alleged necessity to countervail market power of EdF. This argument may be correct from their corporate perspective and to the degree that the merger allows for cost cuts, but it appears ill-justified from a competition policy perspective. Market power in a capacity constrained market as in electricity generation is a system feature that cannot be circumvented by attributing more market power to other existing players. If market power was a problem in the Western European market, demerger of EdF rather than merger of other big players would be the appropriate answer. Merger of other big players aggravates the market power problem. Most critical of all are mergers of EdF with other Central European players.

Crucial to the development of generation competition in Western Europe are decisions of French politicians on the opening of the French market and the subsequent pricing behaviour of the French integrated state electricity monopoly. In the absence of both international interconnection constraints and interconnection mark-ups a uniform Western European wholesale price would prevail. Assuming that EdF currently offers wholesale power in France at moderate price levels and exports at discounted prices to incur an additional margin over variable cost we can think of two possible but realistic scenarios in case of (and only in case of) effective market integration:

- Abuse of market power by EdF: EdF is unrestrained in its strategy and may withhold capacity or drive up bid prices to increase market prices. In this case market power in the French market may be carried over into foreign markets and wholesale prices there could rise considerably.
- EdF cannot make use of market power. Market integration implies that EdF cannot sustain exports at

discounted prices. Market prices abroad increase moderately as exports by EdF decline.

Most interestingly prices outside France would increase under both scenarios, though stronger if market power prevailed. If market integration with France is not achieved, EdF's strategy with regional price differentiation, i.e. low prices for exports may be sustained. In contrast to common perception it is highly questionable whether EdF would have any incentive to sell additional power for example to Germany as this may further reduce prices it can obtain — in spite of rising market shares, turnover or at least profits may fall.

with low generation concentration prices have been low (in the range of 15 Euro/MWh). As we will argue in the next section this is in the range of floor prices as indicated by system marginal cost. We further observe a convergence of prices in Scandinavia (Nordpool) and Germany (SWEF, CEPI) which gives an indication for the exhaustion of arbitrage opportunities between these markets. In more isolated and concentrated markets like in England and Wales or Spain we find price levels well above system marginal cost.

Observed price developments in the European wholesale market

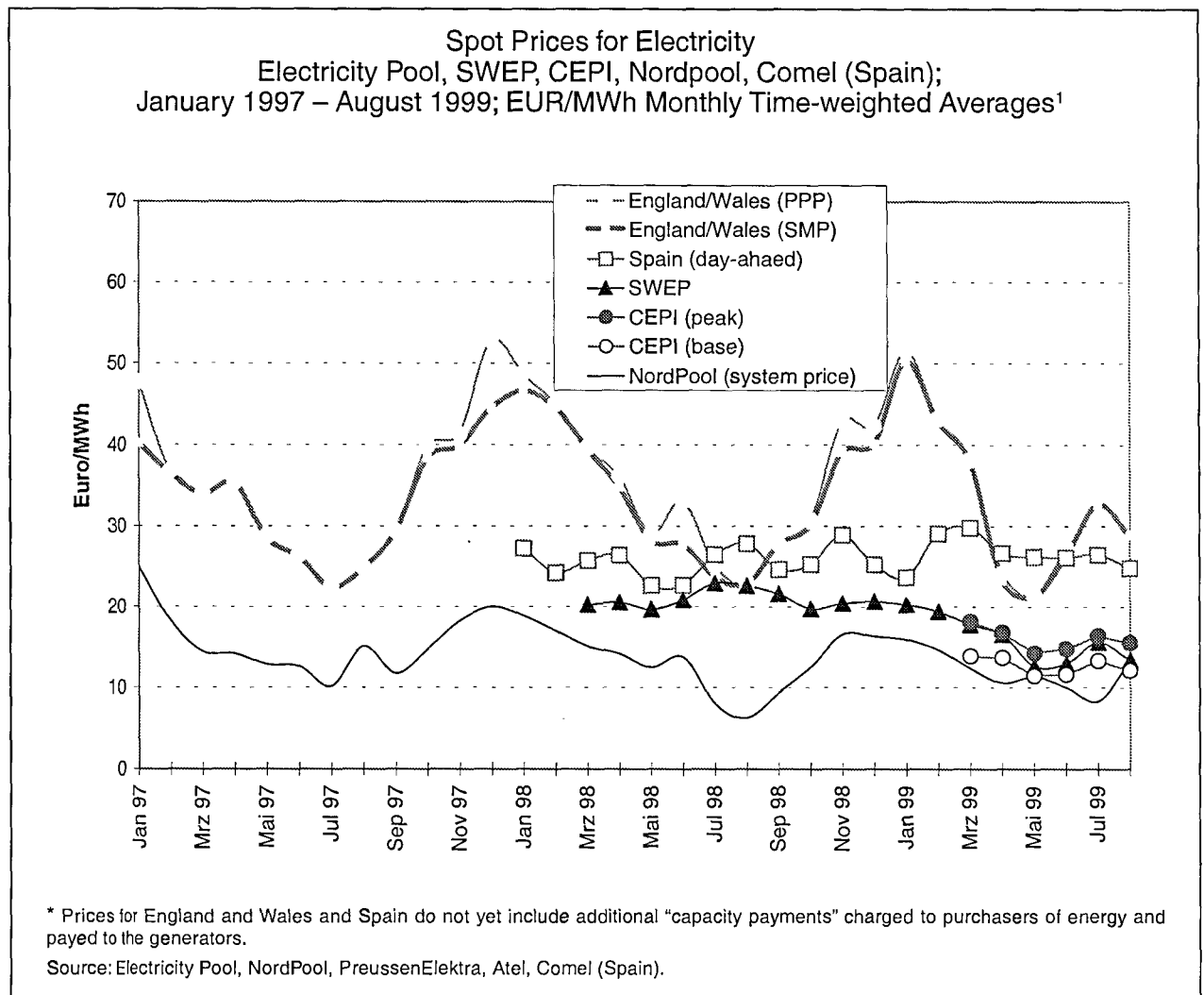
We find that actual wholesale prices have developed in line with our analytical reasoning (Figure 3). In markets

Forecasting prices in the European power market

Methodology

“Co-integration” of regional markets is also suggested by simulation results by the EUROPEAN POWER PLANT DIS-

Figure 3



PATCH MODEL, EUDIS.¹² EUDIS emulates a perfectly competitive European electricity market by minimising total relevant (i.e. not sunk or fixed in the short run) generation and transmission costs (and tariffs), given existing (or future) generation and transmission capacity and their corresponding technical properties. One main input to the model is a database that contains the complete set of condensation and hydro generation capacity in the regions shown in figure 4. Relevant technical properties of power plants comprise their capacity, type of fuel, technology, location, vintage, efficiency, variable costs of measures of environmental protection or variable maintenance, the ability of plants to adjust load in time, minimum load requirements, and a number of other factors.

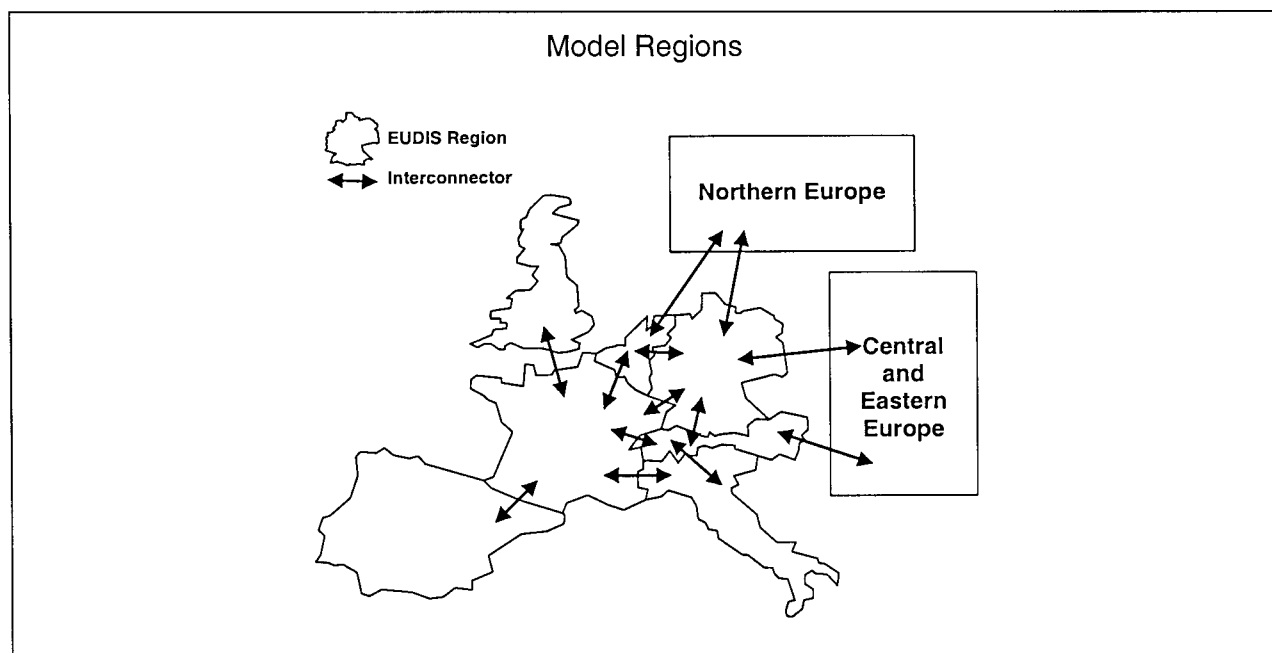
Transmission capacity is modelled only between and not within regions, an approach which is largely justified by the density of the national grids and relatively weak interconnectors. There are historic reasons for the asymmetry between national and international transmission lines, as in the past international interconnections have been considered as serving a somewhat different function than national grids. To put it in a rough manner, national grids had to enable a smooth and relatively efficient allocation of power within a single country, which included large amounts of technical redundancies in the grid. In contrast, the interconnectors rather were considered as just an additional redundancy to further increase security of supply. To use it as a means of saving costs by exploiting international comparative advantages has merely been a side effect.

Regional load demand is assumed to be inelastic in the short term and exogenously given for the single regions; it is represented by load duration curves. Assuming inelastic demand is quite realistic for “normal”, i.e. moderate price fluctuations. Electricity is difficult to substitute in the short term and there are other potentially more costly factors that determine production periods, which cannot be easily shifted from a high electricity price period to a low price period, labor for instance. By using load duration curves one misses some information contained in the sequential load curve. However, we believe, that — given other uncertainties — the computing resources gained by using the simpler duration curve can be used more effectively in other areas of the model.

The used but somewhat bulky modelling approach, which includes some 150,000 variables and a similar number of equations, is superior over potentially leaner econometric, time series or neural network approaches for several reasons: firstly and most important, there is a lack of historic data for estimation and training; secondly, the chosen approach is probably the best way to estimate the impact of changes which have not been observed in the past (structural breaks in general), e.g. the addition of modern generation capacity with new technical properties into the existing system; third, though the model is quite large, it is still possible — sometimes a little bit awkward — to trace back the effects, and fourth, costs structures of

¹² See Kreuzberg (1998, 1999) for a detailed description of the model and further references.

Figure 4



power plants are known and, therefore, do not have to be estimated explicitly or implicitly using econometric or other techniques.

For the present situation in the central regions of Continental Europe the assumption of perfect competition in the electricity generation (not transmission) market is the most reasonable one. This was indicated by theoretical reasons and actual market outcomes and will be supported by the model results as will be shown in the next section. However, other market outcomes can be incorporated in the model using additional bounds on variables (use of capacity for instance) or by modifying pricing rules, which are then still based on system marginal costs, disaggregated with respect to time and geographic regions.

Different modifications have been tested in the past. For example looking at France with monolith EdF with its vast nuclear and hydro capacity, surrounded by markets which are quite competitive on the one hand (especially Benelux, Germany, and the Alpine region), but tend to have higher system marginal cost (SMC) due to a more coal and gas influenced production structure and limited interconnector capacity to France on the other hand, it is unlikely that EdF will charge pure French SMC without any mark-up. The regional lack of competition among distinct power producers in France enables such a strategy for EdF. However, given the huge amount of French nuclear and hydro capacity, seeking to export power, it is also unlikely that the French price level will stay way above the minimum of the price levels of surrounding regions plus transmission charges. Such a pricing rule can easily be mapped in the competitive dispatch model.

Other modifications are usually applied for making long term forecasts up to 2010. Especially towards the end of this period, there will be a need to add new generation capacity to meet increased demand and to replace old capacity, that has reached the end of its technical life time. Pure SMC-prices do not necessarily provide power producers with revenues sufficient to cover both their variable and fixed (sunk) costs. Markets exposed to SMC-pricing therefore tend to face a decreasing capacity endowment. A reduced margin of reserve capacity will be felt first dur-

ing periods of peak demand. The degree of competitiveness will consequently be lower during peak periods, compared to off-peak hours, when capacity is still abundant due to low demand. Even if the capacity bound is not getting strictly binding during peak demand, this will probably enable producers to bid at prices beyond SMC without risking their revenues completely. The exact strategic options are difficult to model and even harder to foresee. Therefore, we currently have chosen a pragmatic (ad hoc) approach in EUDIS for preparing long term price forecasts: We first simulate a perfectly competitive power market and calculate revenues under system marginal costs prices. In a second step we calculate the share of total costs which are not covered by this pricing and then, in a third step define a mark-up to cover full costs, if necessary. This mark-up varies over time (load periods), since it is inversely related to the amount of capacity staying idle in the system. Thus during periods of peak demand there is a large mark-up, during off-peak hours it is virtually nil.

Whether total revenues in the industry will actually be restricted by total average costs is questionable in the long run. Incumbents can always try to deter entry by threatening to lower prices back to SMC. However, uncertainty, the size, diversity and complexity of the system, and an often repeated game all speak in favor of restricting today's long term price forecasts to a level, which just covers total costs and nothing more.

Simulation results

Following the introduction into some of the methodological aspects related to preparing price forecasts for the European electricity market, we will now present a comparison of EUDIS simulation results with real data as they are given in figure 3. Table 1 summarises assumed fuel prices, which are crucial for the simulation. Fuel prices can vary between regions due to taxes, transportation costs or the degree of competitiveness of regional markets. Simulations have been prepared for three typical months (summer [July, August], autumn [September, October], and winter [November, December]). Typical here means that average load demand, precipitation (important

Table 1

		Fuel Prices € cents/kWh						
		German	France	Alps Region	Benelux	Iberian Peninsula	UK	Italy
Hard Coal		0,51	0,51	0,61	0,51	0,51	0,51	0,51
Lignite		0,28	-	0,28	-	0,28	-	-
Oil		0,83	0,83	0,83	0,83	0,83	0,83	0,62
Gas		0,97	1,11	1,11	0,87	1,11	0,87	0,97
Nuclear Fuel		0,18	0,12	0,18	0,18	0,18	0,18	0,18

for hydro power), and availability of plants, have been assumed. This implies that no special effort has been made to exactly map the exogenous set of data prevailing in the reference time period.

Figure 5 depicts the comparison of model output with the observed data. The diagram on the left of figure 5 aggregates spot price estimators for peak (0800h–2000h) and base (0000h–2400h) power in Germany and the Alps region (Austria and Switzerland).¹³ Simulation results indicate that interconnector constraints and the assumed cross-border tariff for power transmission between regions of 0.15 €-Cent/kWh leads to a roughly parallel but not exactly uniform movement of prices in the regions. A result, which is also supported by the data of Figure 3. We observe a general upwards tendency in moving from summer towards winter, due to increased demand during colder and darker seasons and reduced availability of hydro power when precipitation stays frozen as snow on the slopes of the Alps. The latter also explains the intersection of price curves for the two regions between autumn and winter month (September, November).

The centre diagram of figure 5 compares observed prices indices (CEPI) for Germany (to be precise: for the border of the PreussenElektra grid) with EUDIS simulation output for Germany. The level of spot price estimators and the index level do not provide any evidence that would lead us to reject the hypothesis of a competitive market. The real base load prices are even lower than simulation results, which can be attributed to either (i) a miss-specification in the model; (ii) inappropriate parameterisation; or (iii) the actors in the new open spot market for electricity

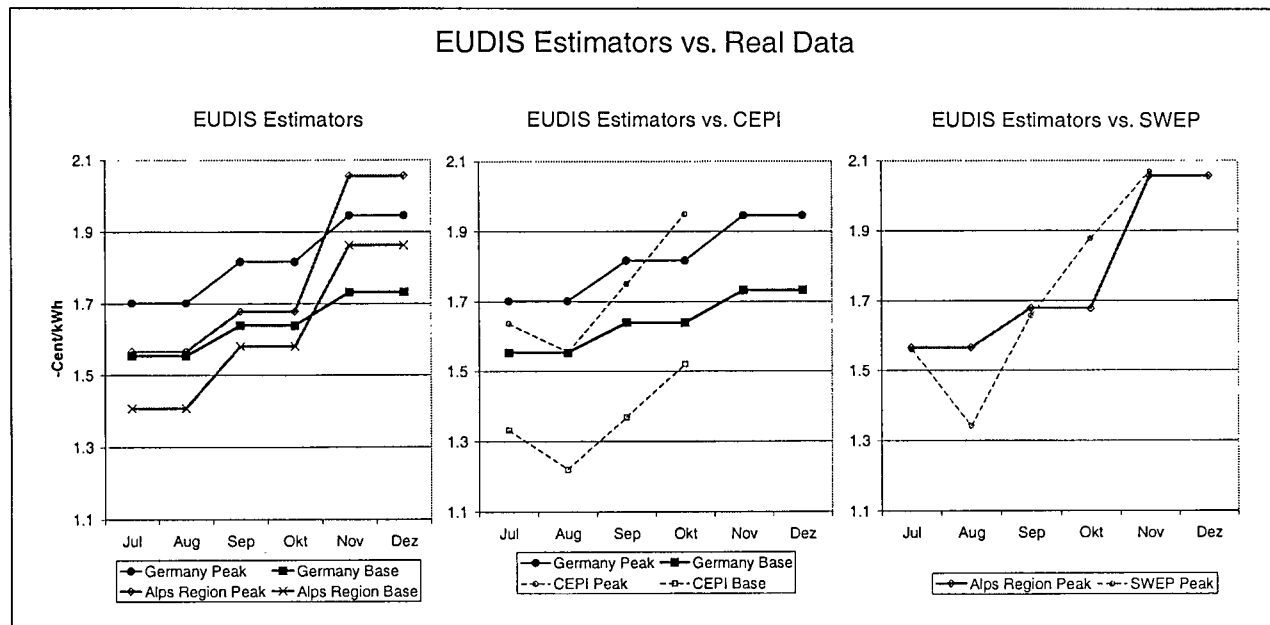
in Germany simply charging prices below SMC for one of two reasons: either (a) because of a lack of experience, or (b) for strategic reasons (dumping to drive (over-) capacity out of the market). The real reason probably is a mixture of (i), (ii), and (iii). However, we believe that especially (ii) is a very reasonable guess, since it quite difficult (if not impossible) to set literally thousands of parameters not just to expected values but to actual realisations.

The last diagram of figure 5 shows recent realisations of the SWEP and compares this with the EUDIS estimators for the Alpine region. If one disregards the value of August the observed data fit even better than the German figures. The outlier in August 1999 can be explained by extraordinarily heavy rain in this year's summer in the Alpine region. This leads to a situation where reservoirs were filled much earlier than expected, which increased sales of Swiss hydro power by some 30% compared to August 1998.

Figure 5 compares model results with actual market performance for regions we have presumed to be very competitive. This assumption does not seem to hold for the UK power market, with a quite limited number of large generation companies. This presumption is also supported by the model results and market outcomes: The average (base) SMC for UK as calculated by EUDIS under the assumed fuel prices range from 1.70 to 1.85 €-Cent/kWh, i.e. these are slightly higher and some-

¹³ There are many more time periods than only peak and base included in the model. Figures in the diagram represent a time-weighted average.

Figure 5



what flatter than the German or the Swiss seasonal price structure. The wider spread is brought about by the large amount of new gas fired CCGT capacity (some 14.5 GW or approximately 26% of simultaneous maximum load in UK) introduced into the UK generation system over the last decade. Given this and given that the UK system is relatively isolated in terms of physical interconnections to the Continent, the UK has a more uniform pattern of marginal plants setting SMC than the Continental European system. Hence, there is a smaller spread between summer and winter SMC.

However, we observe the highest fluctuation in actual prices for the UK. We further observe that the SMP (system marginal price, which is the relevant index for comparison in the UK) ranges from 2.12 to 5.24 €-Cent/kWh and therefore lies considerably above SMC. The average of SMP, i. e. even if the capacity element is not included, would still provide entrants with more revenue than needed to recoup annualised fixed and variable costs of new power plants. We interpret these observations as evidence for the potential exercise of market power by the British generators. It is important to note, however, that this may be an intermediate phenomenon. Market performance may change considerably as new power plants are being built by new players and as the regulator forces incumbents to divest of plants. Then repercussions and dynamic effects on pricing emerge, which are hard to foresee in the oligopolistic UK generation market.

Conclusion

We have demonstrated how considerations of applied industrial economics can inform market participants and public authorities on likely developments upon changes in the market organisation. Several analytical models have been developed that help to explain why prices diverge considerably from system marginal cost in some regional markets while they do not in others. Reality seems to be almost perfectly corresponding to textbook considerations.

We currently observe wholesale prices in Germany and Switzerland to be in accordance with system marginal

cost as indicated by EUDIS. Both markets are characterised by a fairly large number of distinct generators that can reach this region under competitive conditions, although there is still space for discrimination of newcomers under the current transmission regime. In contrast, we have shown that prices above SMC prevail in the more concentrated UK electricity market. Average revenues seem to be above, though close to, average costs of the British system. Whether this is explained by the participants' market power being inherently restricted to raise prices to this level or whether this is simply the maximum level which just does not trigger actions by the regulator is left an open question.

It has been mentioned that one important and distinctive factor of the electricity industry is that there are systematically varying degrees of competition. There are no other industries where one finds cycles as short and as systematic as in the industry we have focussed on. The smallest such cycle in the electricity generation industry lasts only 24 hours from off-peak to peak to off-peak demand again.

The more competitive electricity markets in Europe are currently exposed to price levels which result in shrinking generation capacities — a healthy cure for markets with excess capacity. The exact effect that this decreasing capacity — together with mergers but also entry of new players — will have on strategic options of the actors is hard to foresee. In the future, however, we are likely to face price structures which are just sufficient to cover average costs. Given the varying degrees of competition and of capacity utilisation, mark-ups on SMC will hardly be realised during off-peak periods but probably increase towards peak periods.

How fast markets will converge towards such a sustainable situation and whether this convergence will occur from above (i.e. a high price situation) or below (i.e. a low price situation) depends on: (1) the historic market structure (concentration) within regions, (2) historic capacity endowment of regions (abundant or scarce), (3) and significantly on the transmission pricing and access regime for Europe (discrimination), and (4) last but not least on any further steps taken by regulators.

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Deregulierung und Regulierung im europäischen Strommarkt

Zusammenfassung

Analysiert werden der Status quo und die wahrscheinlichen Entwicklungen des europäischen Strommarktes. Es werden hierfür unterschiedliche nationale Vorgehensweisen bei der Deregulierung der nationalen Strommärkte sowie die Entstehung und unterschiedliche Organisation von Handelsformen (Börsen) für Strom vorgestellt. Die Bedingungen, unter denen Zugang zu der Netzinfrastruktur erlangt werden kann, sind entscheidend, aber nicht allein entscheidend für das Marktergebnis. Diesen Netzzugangsbedingungen wurde ein eigener Abschnitt gewidmet, dem sich eine Konzentrationsanalyse des europäischen Strommarktes anschließt. Den Abschluß der Analyse bildet eine Gegenüberstellung von mit Hilfe des Modells EUDIS erstellten Simulationsergebnissen mit beobachteten Marktergebnissen sowie eine Analyse einiger Besonderheiten bei der Simulation von Preisen auf dem europäischen Strommarkt. Der Artikel endet mit einer Zusammenfassung der wichtigsten Ergebnisse.