

Modeling and Forecasting  
Electricity Loads and Prices

A Statistical Approach

**Rafał Weron**



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## Preface

Since the discovery of the light bulb, electricity has made a tremendous impact on the development of our society. Today, it is hard to imagine a life without it. To provide every factory and household with a sufficient supply of electric energy, electric companies were set up. They used to serve dedicated geographical areas from which consumers had to buy their electricity. Traditionally, centralized regulation of the electricity supply industry was considered necessary to ensure security of supply and efficient production. Efficiency was achieved through economics of scale. The power sector was characterized by a highly vertically integrated market structure with little competition. However, during the last two decades dramatic changes to the structure of the electricity business have taken place around the world.

The original monopolistic situation has been replaced by *deregulated, competitive markets*, where consumers, in principle, are free to choose their provider. To facilitate trading in these new markets, exchanges and pools for electric power have been organized. Everything from real-time and spot contracts to derivatives – such as (standardized, but not marked to market) forward, futures and option contracts – are traded. A power exchange, though, is not a necessity for a deregulated power market. In fact, in most countries the majority of deals – especially medium and long term – are made on a bilateral basis on the so-called over-the-counter (OTC) market. Nevertheless, it has been argued that the establishment of power exchanges has promoted competition and contributed to the high trading activity seen, for instance, in the Nordic market. Furthermore, the exchange serves as a source for updated, independent and good-quality market information.

In a competitive power market electricity can be bought and sold at market prices like any other commodity. As a consequence, the amount of risk borne by electric utilities, power producers and marketers has increased substantially. Successfully managing a company in today's markets takes a fair amount of statistical analysis and educated guesswork. These in turn involve developing dedicated statistical techniques and managing huge amounts of data for modeling, forecasting and pricing purposes.

Unlike the analyses of random samples of observations that are discussed in the context of most other statistics, the analysis of time series is based on the assumption that successive values in the data file represent consecutive measurements taken at equally spaced time intervals. While this assumption is violated for a vast majority of financial data sets, it is fulfilled for power market data. Electricity spot prices, loads, production figures, etc., are sampled 24 hours a day, 365 days a year. This gives us a unique opportunity to apply statistical methods in the way they were meant to be used.

When electricity sectors were regulated, utility monopolies used short-term load forecasts to ensure the reliability of supply and long-term demand forecasts as the basis for planning and investing in new capacity. That is no longer the case where competition has been or is being introduced. The costs of over- or under-contracting and then selling or buying power on the balancing market have increased so much that they can lead to financial distress of the utility. Minimization of volumetric risk has never been of such importance as it is today. As a result, load forecasting has gradually become the central and integral process in the planning and operation of electric utilities, energy suppliers, system operators and other market participants. Its position as one of the major fields of research in electrical engineering is not threatened as well since the financial penalties for forecast errors are so high that research is aimed at reducing them even by a fraction of a percent.

On the other hand, extreme price volatility, which can be even two orders of magnitude higher than for other commodities or financial instruments, has forced producers and wholesale consumers to hedge not only against volume risk but also against price movements. Price forecasts have become a fundamental input to an energy company's decision making and strategic development. As a result of the supply stack structure, load fluctuations translate into variations in electricity prices. However, an inverse relationship has been also observed. In some cases the issue of whether load drives power prices, or vice versa, is not easily answered. Clearly, as they become partially co-determined, load and price forecasting could be treated as one complex task.

It is exactly the aim of this book to present a common framework for modeling and forecasting these two crucial processes for every energy company. The statistical approach is chosen for this purpose as it allows for direct input of relevant statistical properties into the models. Furthermore, it is attractive because physical interpretation may be attached to the components of the models, allowing engineers and system operators to better understand the power market's behavior.

## GUIDE TO THE CHAPTERS

The book is divided into four chapters. The first one introduces the structure of deregulated, competitive electricity markets with the power pools and power exchanges as the basic marketplaces for price discovery. Electricity contracts and the spot price setting mechanism are thoroughly described. The chapter ends with an up-to-date survey of market solutions implemented in different parts of the world, with a particular emphasis on European and North American structures.

Chapter 2 reviews the so-called *stylized facts* of selected power markets. In particular, the spiky nature of electricity prices, the different levels of seasonality inherent in load and price time series, the anti-persistent behavior of prices and the heavy-tailed distributions of returns. Well-known and novel methods, like the Average Wavelet Coefficient and the rolling-volatility technique, are utilized. The findings are illustrated mostly on data from two, not only geographically distinct regions: Scandinavia and California. The first region is well known for the world's oldest, successfully operating power exchange, Nord Pool, and for vast amounts of good-quality data. California, on the other hand, is 'famous' for the market crash of 2000, which led to the blackouts in the San Francisco area in January 2001 and the first bankruptcy of a power exchange in history.

Load forecasting has become increasingly important since the rise of competitive energy markets. Short-term load forecasting can help to estimate load flows and to make decisions that

can prevent overloading and reduce occurrences of equipment failures. Short- and medium-term load forecasting, on the other hand, is important for modeling prices and valuation of spot and derivative contracts for delivery of electricity. Consequently, hourly and daily forecasts up to a few days ahead are of primary interest in everyday market operations. Chapter 3 reviews the relevant techniques, with particular emphasis on statistical methods. Various models with and without exogenous variables are illustrated and compared in two comprehensive case studies.

Finally, Chapter 4 discusses price modeling and forecasting. Six different approaches are surveyed and two – statistical and quantitative – are further studied. This choice is backed by the methods' adequacy to model and forecast electricity prices in two pertinent contexts (and time horizons): short-term forecasting and medium-term or monthly modeling. The former context refers to the situation of bidding for spot electricity in an auction-type market, where players who are able to forecast spot prices can adjust their own production schedules accordingly and hence maximize their profits. The latter is relevant for balance sheet calculations, risk management and derivatives pricing. As in the previous chapter, the theoretical considerations and techniques are illustrated and evaluated using real-world data.

In fact, there are 16 case studies in the whole book, making it a self-contained tutorial to electricity load and price modeling and forecasting. The text is comprehensible for graduate students in electrical engineering, econometrics and finance wanting to get a grip on advanced statistical tools applied in this hot area. Market players looking for new solutions and practical advice will surely find the book attractive as well. All readers will benefit from the Matlab toolbox on the accompanying CD, which not only demonstrates the presented topics but also allows the user to play around with the techniques. The toolbox and its manual will be kept up-to-date on the website (<http://www.im.pwr.wroc.pl/~rweron/MFE.html>) and readers are welcome to download updates from there. Needless to say, all readers are very welcome to contact me with any feedback.

*Rafal Weron*  
Wroclaw, September 2006



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A book like this would not have been possible without the help of many friends, colleagues and students. Various parts of the text have benefited from numerous discussions, also via e-mail and Skype. The software on the attached CD would have been much less advanced and complete if it wasn't for the invaluable programming skills of a number of individuals. I refrain from listing all their names here for fear that this section might otherwise exceed the others in length.

# Complex Electricity Markets

## 1.1 LIBERALIZATION

Over the past two decades a number of countries have decided to take the path of market liberalization. Despite slight differences, the motivation for liberalization of the power sectors world wide has shared common ideological and political reasons. In particular, a strong belief that the success of liberalization in other industries can be duplicated in the power sector and a 'need' for splitting (or *unbundling*) the vertically integrated monopoly structures that traditionally have managed generation, transport and distribution. The introduction of competition has been justified by the perceived benefits of introducing market forces in an industry previously viewed as a natural monopoly with substantial vertical economies. The breach of the natural monopoly character has been possible, in turn, due to changes in generation technologies and improvements in transmission. Therefore the motivation behind electricity liberalization is, in the long run, to promote efficiency gains, to stimulate technical innovation and to lead to efficient investment.

Power market liberalization was pioneered by Chile. The reform, which began in 1982, was based on the idea of separate generation and distribution companies where power was paid for according to a formula based on the cost, a dispatch system with marginal cost pricing and a system of trading power between generators to meet customer contracts. Large-scale privatization began in 1986 and led to the (partial) vertical disintegration of the sector and the formation of a wholesale power trading mechanism.<sup>1</sup>

The Chilean reform was followed by the reorganization of the British electricity sector in 1990. The wholesale market only included England and Wales until 2005, thereafter Scotland as well. The Nordic market opened in 1992, initially in Norway, later in Sweden, Finland and Denmark. In Australia, markets in Victoria and New South Wales began operating in 1994; followed by opening of the Australian National Electricity Market (NEM) in 1998. New Zealand reformed the power sector in the same period, officially launching the market in 1996. In North America, a number of northeastern markets (New England, New York, Pennsylvania–New Jersey–Maryland – PJM) began operating in the late 1990s. California followed in 1998, and Texas and Alberta (Canada) three years later. The number of liberalized electricity markets is steadily growing world wide, but the trend is most visible in Europe.

Some of the pioneers in electricity market reform have been successfully operating for over a decade. Others have undergone substantial changes in design to improve the performance. Yet a few reforms have failed miserably. The California market crash of 2000/2001, the spectacular bankruptcy of Enron that followed, and the widespread blackouts in North America and Europe in 2003 are sometimes used to argue that electricity market liberalization is a flawed concept.

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<sup>1</sup> It should be noted that the Chilean reform conformed with the economic doctrine of the military dictatorship. In the case of the power market, though, it had the long-lasting positive effect of stability. The 2004 revision of the law has not changed the status quo. See Jamasb *et al.* (2005) for a comprehensive review of the electricity sector reforms in Latin America; Pollitt (2005) concentrates solely on the Chilean market.

These failures, however, cannot be attributed solely to market liberalization. The California crisis was due to a coincidence of several factors, one of which was a flawed market design (see Section 1.4.2). Likewise, power market liberalization paved the way for the Enron bankruptcy and the 2003 blackouts, but was not the root cause of these events.

On the other hand, liberalization is praised by others for the positive impact it has had on the economy. The mentioned benefits include a clear trend of falling electricity prices and a more efficient use of assets in the electricity sector. Both 'benefits' are, however, questionable. Net electricity prices have generally decreased, but the new taxes imposed on the prices have in many cases reversed the effect. In particular, the trend of falling prices is not that apparent, if it exists at all, for small or medium size industrial customers and especially for household consumers.<sup>2</sup> We have to remember, though, that prices paid by some consumer groups do not necessarily reflect the costs of producing and transporting electricity. In regulated power markets industrial customers often subsidize retail consumers.

The vertically integrated utilities, that traditionally operated in the power sector, have had the tendency to create substantial overcapacity. Market liberalization has generally reduced this overcapacity. In addition it has also been shown to provide gains from higher efficiency in the operation of generation, transmission and distribution services. But since liberalization is expected to bring economic benefits in the long run, in the short term certain groups (like the previously subsidized household consumers) may not realize immediate benefits or may even experience losses.

Another controversial issue is the ability of liberalized power markets to provide sufficient incentives for investment in new generation (or transmission) capacity. In the new environment, investment decisions are no longer centrally planned but are the outcome of competitive forces. Consequently, capital-intensive technologies with long construction times are generally avoided, even if their marginal costs are low. Instead generation plants that can be built in short time horizons (like the gas-fueled plants) are preferred. But even then, the expectation of lower prices can cause private investors to postpone expenditures on new generation capacity or the expansion of transmission network. This puts policy makers under pressure to intervene. Consequently, there is an ongoing debate whether to establish capacity payments (as in a number of Latin American countries and Spain), organize capacity markets (as in the northeastern United States) or to have 'energy only' markets (as in Australia and New Zealand).

The basic idea of *capacity payments* (originally introduced in Chile in 1982) is to award to each generator a daily payment which is a measure of the contribution of the generator to the reliability of the power system, i.e. its availability. International evidence suggests, however, that capacity payments create poor incentives to alleviate the capacity problem and may even worsen it. For instance, generators may try to increase capacity payments by making fewer capacity resources available thereby increasing, rather than decreasing, the probability of shortage.

Quantity-based capacity payment systems (as opposed to the price-based capacity payments discussed above) generally have taken the form of *installed capacity (ICAP) markets*. The main purpose underlying the introduction of these markets has been to ensure that adequate capacity is committed on a daily or seasonal basis to meet system load and reserve requirements. The distributors that sell electricity to end-user consumers must satisfy their capacity obligations, which equal their expected peak monthly loads plus a reserve margin. They can accomplish this,

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<sup>2</sup> See <http://www.iea.org>, <http://www.eurelectric.org> and <http://www.europa.eu.int/comm/eurostat/> for relevant statistical data and comparisons.

either by internal or bilateral transactions, or through the capacity market in which generators sell a recall right that empowers the system operator to recall them in the event of shortages. As the markets matured, market coordinators realized a need to encourage generator reliability and remove a potential source of market power. Consequently, *unforced capacity* (UCAP) credits were developed, which are calculated by taking the ICAP and adjusting it on the basis of the reliability of the generator.

In the '*energy only*' markets<sup>3</sup> the wholesale electricity price provides compensation for both variable and fixed costs. The 'price' we have to pay for this are the price spikes, i.e. abrupt and generally unanticipated large changes in the spot price that in extreme cases can lead to bankruptcies of energy companies not prepared to take such risks (see Case Study 2.2.1). Price spikes should send signals to investors that new generation capacity is needed. However, if the spikes are rare and not very extreme they may not provide sufficient motivation. In such a case regulatory incentives (e.g. capacity payments) to prompt timely and adequate investment may be necessary. A related social issue is whether consumers are willing to accept price spikes at all. If not, protective price caps are necessary, which again require regulatory incentives for investment in new capacity.

Clearly electricity market liberalization is a challenging and ongoing process. It requires not only strong and sustained political commitment, but continuous development as well. Only then will it bring the expected benefits to the economy and the society. What complicates the situation is the fact that there is not one single best market model. In every case specific decisions have to be made that take into account the economic and technical characteristics of a given power system. However, no matter what are the actual regulations regarding unbundling, third-party access (TPA)<sup>4</sup> or cost-reflective pricing, there is one common feature of all successful markets: a formal price quotation mechanism. We will look more closely at this mechanism in the following sections.

## 1.2 THE MARKETPLACE

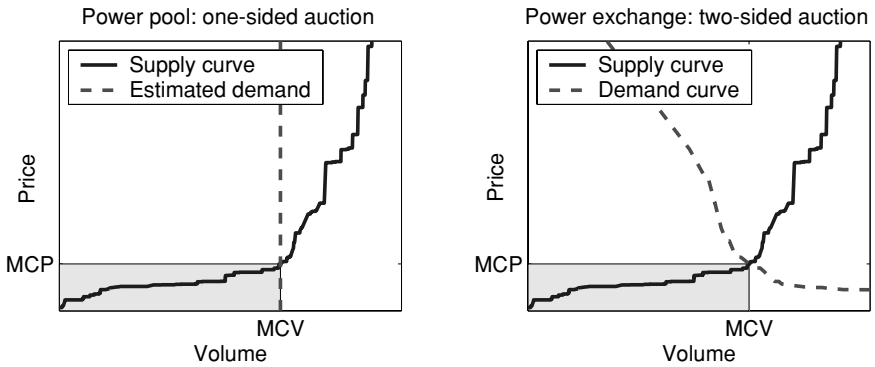
### 1.2.1 Power Pools and Power Exchanges

Liberalization of the power sector has created a need for organized markets at the wholesale level. Two main kinds of market for electricity have emerged: *power pools* and *power exchanges*. The differences between them can be explained by using two criteria: initiative and participation. Power pools and power exchanges share many characteristics and distinguishing between them is not always trivial. In particular, the oldest and one of the most mature power exchanges in the world is called *Nord Pool*.

Two types of power pools can be identified: technical and economic. *Technical pools* or *generation pools* have always existed. Vertically integrated utilities used a pool system to optimize generation with respect to cost minimization and optimal technical dispatch. In such a system the power plants were ranked on merit order, based on costs of production. Hence, generation costs and network constraints were the determining factor for dispatch. Trading activities were limited to transactions between utilities from different areas. International trade activity was limited, due to a low level of interconnection capacity.

<sup>3</sup> Also called 'one price only' markets (IEA 2005a).

<sup>4</sup> TPA regulations define and govern the access to the transmission and distribution network. In the European Union the vast majority of countries have opted for regulated TPA, under which prices for access are published by the system operator and are not subject to negotiation.



**Figure 1.1** Power pool vs. power exchange price formation mechanism. *Left panel:* In a power pool the *market clearing price (MCP)* is established through a one-sided auction as the intersection of the supply curve (constructed from aggregated supply bids) and the estimated demand (which automatically defines the *market clearing volume, MCV*). *Right panel:* In a power exchange the MCP is established through a two-sided auction as the intersection of the supply curve (constructed from aggregated supply bids) and the demand curve (constructed from aggregated demand bids)

*Economic pools* or simply *power pools* have been established to facilitate competition between generators. They have mainly been created as a public initiative by governments willing to introduce competition in generation. This system has been used world wide, for instance, in England and Wales (before the introduction of the New Electricity Trading Arrangements – NETA, see Section 1.3.1), Spain, Alberta and PJM (Pennsylvania–New Jersey–Maryland).

Participation in an economic pool is mandatory, i.e. no trade is allowed outside the pool. Moreover, since trading has to account for numerous technical limitations, like plant availability and unit commitment, the participants can only be generators. They bid based on the prices at which they are willing to run their power plants. The *market clearing price (MCP)* is established through a one-sided auction as the intersection of the supply curve (constructed from aggregated supply bids) and the estimated demand (which automatically defines the *market clearing volume, MCV*), see the left panel in Figure 1.1. Because of the technical aspects involved, these bids can be very complex. Hence, the price determination mechanism involves a computationally demanding constrained optimization leading to a low level of transparency.

On the other hand, a *power exchange (PX)* is commonly launched on a private initiative, for instance, by a combination of generators, distributors and traders. Most of the recently developed European markets (including the Netherlands, Germany, Poland, France, Austria) are based on this model; see Table 1.1 with the timeline of organized day-ahead electricity markets. Participants include generators, distribution companies, traders and large consumers. Participation in the exchange is voluntary. However, there are some exceptions. For instance, the California Power Exchange (CalPX) was mandatory during the first years of operation in order for it to develop liquidity. Nord Pool, is a voluntary exchange at the national level but is mandatory for cross-border trade. The Amsterdam Power Exchange (APX) is mandatory for players who obtain interconnector capacity on the daily auction.

The genuine role of a power exchange is to match the supply and demand of electricity to determine a publicly announced market clearing price (MCP). Generally, the MCP is not

**Table 1.1** Timeline of organized day-ahead electricity markets

Country	Year	Name
UK	1990	England & Wales Electricity Pool <sup>a</sup>
Norway	1992	Nord Pool <sup>b</sup>
Sweden	1996	Nord Pool
Spain	1998	Operadora del Mercado Español de Electricidad (OMEL) <sup>c</sup>
Finland	1998	Nord Pool
USA	1998	California Power Exchange (CalPX) <sup>d</sup>
Netherlands	1999	Amsterdam Power Exchange (APX)
USA	1999	New York ISO (NYISO)
Germany	2000	Leipzig Power Exchange (LPX) <sup>e</sup>
Germany	2000	European Energy Exchange (EEX)
Denmark	2000	Nord Pool
Poland	2000	Towarowa Gielda Energii (Polish Power Exchange, PolPX)
USA	2000	Pennsylvania–New Jersey–Maryland (PJM) Interconnection
UK	2001	UK Power Exchange (UKPX) <sup>f</sup>
UK	2001	Automated Power Exchange (APX UK) <sup>g</sup>
Slovenia	2001	Borzen
France	2002	Powernext
Austria	2002	Energy Exchange Austria (EXAA)
USA	2003	ISO New England
Italy	2004	Italian Power Exchange (IPEX)
Czech Rep.	2004	Operátor Trhu s Elektřinou (OTE)
USA	2005	Midwest ISO (MISO)
Belgium	2006	Belgian Power Exchange (Belpex)

<sup>a</sup> In March 2001, the Pool was abolished and replaced by NETA.

<sup>b</sup> Despite the name, Nord Pool is a power exchange.

<sup>c</sup> Although officially called a power exchange, OMEL is more like a power pool.

<sup>d</sup> CalPX ceased operations in January 2001 and subsequently went bankrupt.

<sup>e</sup> LPX merged with EEX in 2002.

<sup>f</sup> Since 2004, UKPX is part of the APX Group (formerly APX).

<sup>g</sup> APX acquired APX UK in February 2003.

established on a continuous basis, but rather in the form of a conducted once per day two-sided<sup>5</sup> auction. It is given by the intersection of the supply curve (constructed from aggregated supply bids) and the demand curve (constructed from aggregated demand bids), see the right panel in Figure 1.1. Buyers and suppliers submit bids and offers for each hour of the next day and each hourly MCP is set such that it balances supply and demand. In a *uniform-price* (or *marginal*) *auction* market buyers with bids above (or equal to) the clearing price pay that price, and suppliers with offers below (or equal to) the clearing price are paid that same price. Hence, a supplier would be paid 100 EUR/MWh for the quantity sold in the spot market (whenever the clearing price happened to be 100 EUR/MWh) regardless of his actual bid (and his marginal costs).<sup>6</sup> In contrast, in a *pay-as-bid* (or *discriminatory*) *auction* a supplier would be paid exactly the price he bid for the quantity transacted; in effect he would be paid an amount that more closely corresponds to his marginal costs. This, however, leads to the problem of ‘extra money’

<sup>5</sup> As opposed to the one-sided auction of a power pool, where only one side – the suppliers – send in their bids.

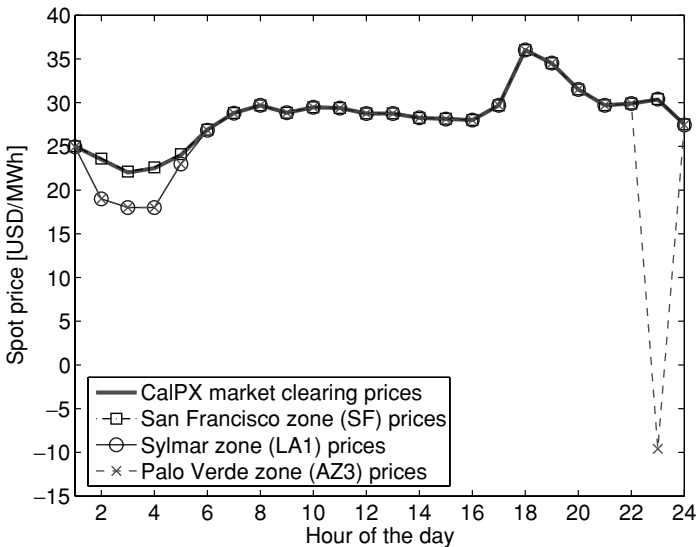
<sup>6</sup> Consequently, the uniform-price auction has been criticized for having the consumers systematically pay too much for electricity. Cramton and Stoft (2006) argue that this is not the case.

paid by buyers, but not paid to suppliers. On the other hand, in a uniform-price auction the money paid by buyers is exactly equal to the money received by suppliers. The list of pros and cons of the two approaches is much longer and the choice between them is not obvious. In practice, however, most market designs have adopted the uniform-price auction, the UK under NETA (see Section 1.3.1) is one of the few exceptions.

### 1.2.2 Nodal and Zonal Pricing

When there is no transmission congestion, MCP is the only price for the entire system. However, when there is congestion, the *locational marginal price* (LMP) or the *zonal market clearing price* (ZMCP) could be employed. The former is the sum of generation marginal cost, transmission congestion cost and cost of marginal losses (although the cost of losses is usually ignored), and can be different for different buses (or nodes), even within a local area. Nodal prices are the ideal reference because the electricity value is based on where it is generated and delivered. However, they generally lead to higher transaction costs and greater complexity of the pricing mechanism. On the other hand, the zonal price may be different for various zones or areas, but is the same within a zone, i.e. a portion of the grid within which congestion is expected to occur infrequently or has relatively low congestion-management costs. Interestingly, these prices can take negative values, as in Figure 1.2, which makes them diametrically different from other financial or commodity prices.

Nodal (locational) pricing developed in highly meshed North American networks where transmission lines are criss-crossing the electricity system. In Australia, where the network



**Figure 1.2** California Power Exchange market clearing prices (MCP) for each hour of December 3, 1999. After congestion management is performed, the final day-ahead schedules are issued and zonal market clearing prices (ZMCP) are calculated. The hourly ZMCP for three selected zones within the California network – Palo Verde, San Francisco and Sylmar – are also depicted. At times the zonal prices deviate significantly from the unconstrained MCP. Here the Palo Verde clearing price is even negative for one hour, a behavior generally not observed in other financial or commodity markets

structure is simpler, zonal pricing was successfully implemented. Although the European network is rather complex it is evolving into a zonal market, often with countries constituting entire zones. This may have the negative impact of obscuring price signals and limiting efficiency.

### 1.2.3 Market Structure

The market clearing price is commonly known as the *spot price*. The spot electricity market is actually a day-ahead market, as trading typically terminates the day before delivery. Recall that for financial assets and most commodities the term ‘spot’ defines a market for immediate delivery and financial settlement up to two business days later. Such a classical spot market would not be possible for electricity, since the (*transmission*) *system operator* (TSO, SO) needs advanced notice to verify that the schedule is feasible and lies within transmission constraints.

For very short time horizons before delivery the TSO operates the so-called *balancing* (or *real-time*) *market*. This technical market is used to price deviations in supply and demand from spot or long-term contracts. The TSO needs to be able to call in extra production at very short notice, since the deviations must be corrected in a matter of minutes or even seconds to ensure physical delivery and to keep the system in balance. Spot and balancing markets serve different purposes and are complementary. Their functioning is quite different, however, and they should not be confused. Note, that in the USA the spot and balancing markets are often referred to as ‘forward’ and ‘spot’, respectively.<sup>7</sup> We prefer to use a different, say European, convention and reserve the term ‘forward market’ for transactions with delivery exceeding that of the day-ahead market. With this convention the spot market is the nearest to delivery non-technical market. Unless otherwise stated, in this monograph we will focus our attention on spot (i.e. day-ahead) markets.

Just for the record, the balancing market is not the only technical market. To minimize reaction time in case of deviations in supply and demand the system operator runs the *ancillary services market* which typically includes the down regulation service, the spinning and non-spinning reserve services and the responsive reserve service. In some markets the TSO operates also the *generating capacity market* and/or the *transmission capacity market*. The generating capacity market can address the problem of incentives for investment in new generating capacity. Trading in such a market can take the form of imposing on wholesale traders and large loads connected directly to the transmission system the obligation to purchase some amount of generating capacity (e.g. relative to their maximum demand), see also Section 1.1.

### 1.2.4 Traded Products

The commodization of electricity has led to the development of novel types of contracts for electricity trading. These contracts can either be sold in bilateral (over-the-counter, OTC) transactions or on organized markets. They can also be physical contracts (for delivery) or financial contracts (for hedging or speculation). All contracts share four well-defined characteristics: delivery period, delivery location, size and price. Other characteristics can vary widely.

The physical contracts can be classified as long term (futures, forwards and bilateral agreements with maturities measured even in years) and spot, i.e. short term. Since electricity cannot be economically stored, this range of contracts is necessary to keep supply and demand in balance. Market participants need daily, and even hourly, contracts to fulfill the variable – and

<sup>7</sup> See, for example, Longstaff and Wang (2004) and Popova (2004).



**Table 1.2** Annual trading volumes of the two largest European power exchanges (source: <http://www.nordpool.no>, <http://www.eex.de>). For comparison the total demand figures for years 2002-2004 in the respective areas are provided (source: <http://www.eurelectric.org>). All values are in TWh

Nord Pool	2002	2003	2004	2005
Demand (DK, FI, NO, SE)	387	379	389	n.a.
Day-ahead market	124	119	167	176
Futures market	1019	545	590	786
OTC clearing	2089	1219	1207	1316
EEX	2002	2003	2004	2005
Demand (Germany)	539	550	554	n.a.
Day-ahead market	33	49	60	86
Futures market	117	151	156	262
OTC clearing	–	191	182	255

predictable only to a certain extent – consumption. The short-term spot contracts are usually traded through an organized exchange, but the market share varies from country to country.

To cover their future consumption, utilities buy electricity in advance using monthly or annual contracts. Many power exchanges provide a market for long-term electricity derivatives, like futures and options (see Section 4.4.6). Nevertheless, long-term contracts are typically negotiated on a bilateral basis. The reason for this is the relatively low liquidity of the exchange-traded derivatives markets. Currently only at Nord Pool the volume of exchange-traded derivatives surpasses the market demand (i.e. of Denmark, Finland, Norway and Sweden), see Section 1.3.2 and Table 1.2. However, when the exchange clearing of OTC derivatives is also taken into account, other markets (for instance, the European Energy Exchange) come close to this liquidity threshold. In fact the clearing of the OTC transactions has been a highly successful enterprise, especially at Nord Pool.

A special type of long-term contracts are the so-called Power Purchasing Agreements (PPA). In some countries (e.g. Hungary, Poland, Portugal) they still constitute a considerable part of the market. For instance, in Poland the PPA (known as ‘kontrakty długoterminowe’, KDT) were entered into between power producers and the Polish Power Grid Company (PSE SA) in the mid-1990s and currently still cover about 40% of the total production. They were aimed at the modernization of the generation industry, with the objective of pollution reduction. More than 4 billion dollars have been invested using bank loans guaranteed by these contracts.

Since many of the PPA were entered into before the start of the liberalization process, they might comprise a market hindrance. In general, they are not in line with the principles governing a competitive market. If the PPA are terminated, stranded costs<sup>8</sup> will have to be paid to compensate for the phasing out of these contracts. Other solutions to this problem are also possible, including transformation into vesting contracts<sup>9</sup> or introduction of a levy system.

<sup>8</sup> *Stranded costs*, also known as *stranded investments* or *stranded assets*, occur in competitive markets when customers change the supplier, thereby leaving the original supplier with debts for plants and equipment it may no longer need and without the revenue from the ratepayers the plants were built to serve.

<sup>9</sup> Vesting contracts are a transitional mechanism supporting the development of a competitive electricity market. They are agreements between generators and utilities, with the system operator as an intermediary, for delivery of electricity at prespecified prices (varying between seasons and days/hours of the week). Their volumes are set to cover the average (predicted) demand of the utilities’ franchised customers. Vesting contracts have been popular in Australia (Kee 2001, Mielczarski and Michalik 1998); currently (since April 2006) they are in use in the province of Western Australia.

Another interesting type of long-term contracts present in electricity markets are the CO<sub>2</sub> emissions allowances. Through the ‘non-environment friendly’ generation process they influence electricity prices. A generator producing more electricity and hence polluting more is obliged to buy extra allowances for a given year. Conversely, a generator producing less electricity (or from ‘cleaner’ sources) during a given year can sell the excess allowances for extra profit. In the European Union the first phase of the *emissions trading scheme* (ETS) covers the period 2005–2007. It is the world’s largest market for CO<sub>2</sub> emissions allowances covering the 25 Member States of the EU and approximately 12 700 installations. Since the beginning of 2005 Nord Pool and the European Energy Exchange offer spot and forward contracts on CO<sub>2</sub> allowances, but the majority of trading takes place on the OTC bilateral market. The players are currently acting under imperfect (scarce) information and the prices are very volatile. It is expected that in the second phase (2008–2012) the market will be more transparent and predictable.

## 1.3 EUROPE

In the sections to follow we will briefly report on the changes that have taken place and review the main characteristics of various competitive power markets. By no means will the selection be complete or even representative. Some of the descriptions will become outdated in a few years as the power markets are at an early stage of development characterized by rapid and often drastic changes. Despite its limitations, the review will give us a better understanding of the problems, solutions and the variety of today’s electricity markets. Taking the Nordic power exchange as an example we will also describe the bidding practices and the spot price setting procedure. We will start, though, chronologically with the oldest European market and the world’s first day-ahead organized marketplace for electricity.

### 1.3.1 The England and Wales Electricity Market

The creation of organized electricity markets started in Europe in 1989 as a result of the UK Electricity Act. The two main aspects of the reform consisted of dismissing the Central Electricity Generating Board (CEGB), previously a vertically integrated monopoly for both production and transport, and the foundation of the pool. Three companies were created, but only two-, National Power (50% share) and Powergen (30% share) – were dominant in price-setting. Those two held all of the fossil-fuel plants, with the third company (Nuclear Electric) providing baseload nuclear power and essentially being a price taker. The England and Wales Electricity Pool began operating in 1990 and was the world’s first organized market for wholesale electricity. The pool was a compulsory day-ahead last price auction with non-firm bidding, capacity payments for plant declared available and firm access rights to transmission. Electricity was bought and sold on a half-hourly basis. The pool was a one-sided market because at that time it was considered to be impossible to include sellers.

The system operator estimated the demand for each half-hour. Each bidder submitted a whole schedule of prices and quantities. The unconstrained *system marginal price* (SMP) was defined by the intersection of the half-hourly forecast demand of the system operator with the aggregate supply function provided by generators, see Figure 1.1. The price paid to generators, the *pool purchase price* (PPP), was the SMP plus a capacity payment (executed in case of congestion). The price paid by the supplier, the *pool selling price* (PSP), was calculated by taking into account the actual production of generators together with additional cost for

ancillary services and system constraints. In addition to the pool, generators and suppliers usually signed bilateral financial contracts to hedge against the risk of pool price volatility. These agreements, called *contracts for differences* (CfD), specified a strike price and volume and were settled with reference to the pool price. If the pool price was higher than the agreed price on the CfD, the producer paid the difference to the consumer; if it was lower, the consumer paid the difference to the producer.

The pool faced many criticisms: lack of transparency in the price determination process (price setting was extremely complex), inadequacy of the capacity and availability payments (which rewarded generators for making plants available, not for operating them) and admission to keep market prices well above marginal production costs. In fact, the latter criticism was more due to the duopoly of National Power and Powergen than to the flawed design of the Pool. Since the inception of the market, the two companies steadily increased the prices so that, by 1994, wholesale spot prices were nearly twice the marginal cost.<sup>10</sup> The prospect of large generating profits brought, in turn, new entrants to the market. This process picked up speed in 1999 with unbundling of retail supply. In a surge to become vertically integrated entities, National Power and Powergen started selling their generating assets. With the excess capacity and reduced market concentration the wholesale prices started falling after year 2000. The household prices remained high, though, benefiting vertically integrated companies and eventually leading to bankruptcies of some of the generation-only companies a few years later.

In March 2001 the New Electricity Trading Arrangements (NETA) were introduced, replacing the pool with a system of voluntary bilateral markets and power exchanges.<sup>11</sup> Soon after introduction of NETA, over-the-counter (OTC) power trading increased significantly. The OM London Exchange established the UK Power Exchange (UKPX) and launched an electricity futures market. Nine months later, as the Electricity Pool ceased operations, the UKPX added a spot market in which spot contracts for half-hour periods were traded, see Table 1.1. At the same time, two other independent power exchanges began operations: the UK Automated Power Exchange (APX UK) opened a spot market and the International Petroleum Exchange (IPE; currently IntercontinentalExchange, ICE) launched a futures market. In 2003 APX UK was acquired by the Dutch APX and in 2004 they merged with UKPX into the APX Group, currently the largest electricity spot market in Britain.

As with continental European markets, liquidity in the England and Wales market suffered as a result of the withdrawal of the US-based traders in 2002–2003 (a fall in volume of around 30% has been reported). Moreover, with the vertically integrated power companies dominating by that time, the wholesale market lost its importance as a revenue source for the major players. A decline in wholesale prices became simply an internal transfer of profits from the generation to the retail branch of the company. As a byproduct, the market became less attractive to new entrants. The consolidated vertical business model<sup>12</sup> that emerged is remarkably different from its origins with unbundled generation, and ironically similar to the pre-liberalization model. Despite all this, the England and Wales market is still a liquid trading market. However, the spot exchange-traded volumes amount to a very small share of the wholesale market – around 1.5% of total demand in 2004.<sup>13</sup> As the market is dispersed via bilateral and broker-based

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<sup>10</sup> See Bower (2004) and Bunn (2006) for relevant data.

<sup>11</sup> Note, that the NETA trading system pays generators not in a uniformly but in a discriminatory (pay-as-bid) fashion.

<sup>12</sup> Bunn (2006) suggests that such a model is convenient for regulators, in terms of dealing directly with the main players and implementing energy policy (including new investments) by persuasion or treat, something that would not be possible with independent generators.

<sup>13</sup> See Cocker and Lundberg (2005).

trading, it does not have a single index, but rather several competing price indices. Broker-quoted prices are available up to 36–42 months ahead. The UKPX offers limited OTC clearing, but no centralized clearing is currently available.

### 1.3.2 The Nordic Market

The Nordic commodity market for electricity is known as Nord Pool. It was established in 1992 as a consequence of the Norwegian energy act of 1991 that formally paved the way for the deregulation of the electricity sector of Norway. At this time it was a Norwegian market, but in the years to follow Sweden (1996), Finland (1998) and Denmark (2000) joined in. Only at this point in time was it fair to talk about a power exchange for the Nordic region.

Nord Pool was the world's first international power exchange. In this market, players from outside the Nordic region are allowed to participate on equal terms with 'local' exchange members. To participate in the spot (physical) market, called *Elspot*, a grid connection enabling power to be delivered to or taken from the main grid is required. About 40% of the total power consumption in the Nordic region is traded in this market (see Table 1.2) and the fraction has steadily been increasing since the inception of the exchange in the 1990s. Additionally, a continuous hour-ahead *Elbas* market is also operational in Finland, Sweden and eastern Denmark.

In the financial *Eltermin* market power derivatives, like forwards (up to three years ahead), futures, options and contracts for differences (CfD; for price area differentials, using the system day-ahead price as the reference price) are being traded. In 2004 the derivatives traded at Nord Pool accounted for 590 TWh, which is over 150% of the total power consumption in the Nordic region (389 TWh), see Table 1.2. In addition to its own contracts, Nord Pool offers a clearing service for OTC financial contracts, allowing traders to avoid counterparty credit risks. This is a highly successful business, with the volume of OTC contracts cleared through the exchange surpassing the total power consumption three times in 2004! In 2005 the volumes increased further. In addition, on February 11, 2005 Nord Pool became the first exchange in the world to start trading in European Union allowances for carbon dioxide emissions. From that date until December 31, 28 million tons of CO<sub>2</sub> were traded and cleared over Nord Pool, making it the second largest exchange in this segment.

There are today over 300 market participants from over 10 countries active on Nord Pool. These include generators, suppliers/retailers, traders, large customers and financial institutions. The success of Nord Pool can be explained by several factors. First, the industry structure is very fragmented with over 350 generation companies. The largest player (Vattenfall) has a market share of only 20% (Cocker and Lundberg 2005). Such a structure obviously facilitates competition. Second, large amount of hydropower allows storage and flexibility in production. Third, the structure of the network is relatively simple, compared to continental Europe, which facilitates congestion management. Finally, the level of collaboration between system operators, governments and regulators is very high in contrast to the many conflicts of interest between continental European countries.

### 1.3.3 Price Setting at Nord Pool

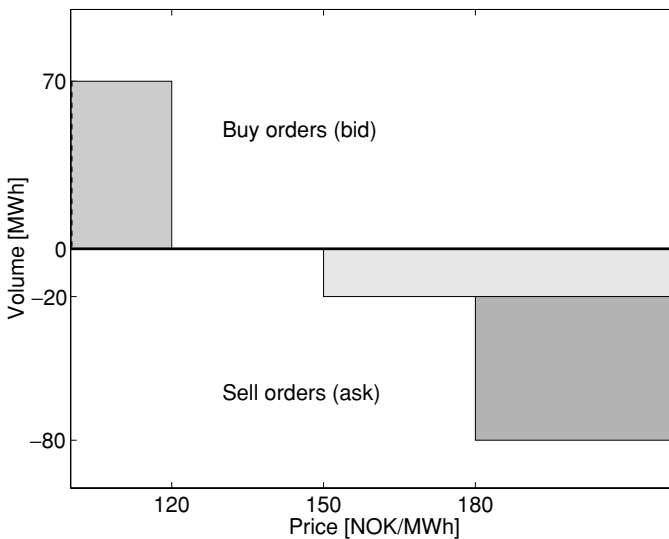
At Nord Pool the spot price is a result of a two-sided uniform-price auction for hourly time intervals (see Figure 1.1). It is determined from the various bids presented to the market administrator up to the time when the auction is closed. Before proceeding, we should stress

that the bidding procedures are specific to every exchange, and therefore are not general. However, the system used by Nord Pool shares many common features with other power exchanges.

The market for trading power for physical delivery is called *Elspot*. Strictly speaking, Elspot is a day-ahead market. What is traded are one-hour-long physical power contracts, and the minimum contract size is 0.1 MWh. At noon (12 p.m.) each day, the market participants submit to the market administrator (Nord Pool) their (bid and ask) offers for the next 24 hours starting at 1 a.m. the next day. This information is provided electronically via the Internet (*Elweb*) with a resolution of one hour, i.e. one for each hour of the next day. Such information should contain both price and volume of the bids.

To be formally correct, there are in fact three possible ways of bidding at Elspot. *Hourly bidding* consisting of pairs of price and volume for each hour. In *block bidding*, the bidding price and volume are fixed for a number of consecutive hours. *Flexible hourly bidding* is a fixed price and volume sales bid where the hour of the sale is flexible and determined by the highest (next day) spot price that is above the price indicated by the bid.

The market participants are free (for hourly bidding) to provide a whole sell and/or buy stack for each hour. For instance, a power generator could be more interested in selling larger quantities of electricity if the price is high than if it is low. This is illustrated by Figure 1.3, which depicts a bid/ask stack for a given hour for a fictitious power generator. The generator is interested in selling electric power if the price is 150 NOK/MWh (or above). Furthermore, if the price is at least 180 NOK/MWh the power generator wants to sell even larger quantities for that particular hour. Notice also that this market participant, in addition, is willing to buy electricity if the price is low, at most 120 NOK/MWh.



**Figure 1.3** The (bid and ask) orders for a given hour of a fictitious power generator. At *Elspot* buy orders are positive numbers, while those of sell orders are negative. In this particular example there is one purchase order of 70 MWh at a maximum price of 120 NOK/MWh, a sell order for -20 MWh with a minimum price of 150 NOK/MWh and a second sell order for another -60 MWh set to at least 180 NOK/MWh

The fact that power generators also are willing to buy power is not uncommon. They have typically committed themselves, at a mutually agreed upon price, to long-term contracts with large consumers. These contracts have to be honored at any time during the contract period. A power generator is, of course, interested in optimizing his profit. This can also be achieved by buying electricity during low price periods, and thereby saving own production potential for periods when the price is higher. Such strategy can be profitable especially in the Nord Pool area, where a large fraction of the production comes from hydro power that is easily adjustable (future production is directly related to the filling fraction of the water reservoir).

By 12 p.m. Nord Pool closes the bidding for the next day and for each hour proceeds to make cumulative supply and demand curves (see the right panel in Figure 1.1). Since there must be a balance between production and consumption, the system spot price for that particular hour is determined as the price where the supply and demand curves cross. Hence the name *market cross* or *equilibrium point*. Trading based on this method is called *equilibrium trading*, *auction trading* or *simultaneous price setting*. If the data does not define an equilibrium point, no transactions will take place for that hour.<sup>14</sup>

After having determined the system price for a given hour of the next day's 24-hour period, Nord Pool continues by analyzing for potential *bottlenecks* (grid congestions) in the power transmission grid that might result from this system price. If no bottlenecks are found, the system price will represent the spot price for the whole Nord Pool area. However, if potential grid congestions may result from the bidding, so-called *area spot prices* (zonal prices), that are different from the system price, will have to be computed. The idea behind the introduction of area (zonal) prices is to adjust electricity prices within a geographical area in order to favor local trading to such a degree that the limited capacity of the transmission grid is not exceeded. How the area prices are determined within Nord Pool differs between, say, Sweden and Norway, and we will not discuss it further here.

We should keep in mind that the system price is the price determined by the equilibrium point independent of potential grid congestions. The area (zonal) prices will only differ from this price for those hours when transmission capacity in the central grid is limited. The system price is therefore typically less volatile than the area prices. In this monograph we focus on system prices, unless stated otherwise.

### 1.3.4 Continental Europe

The liberalization process started in the European Union in 1997 with the Directive 96/92/EC.<sup>15</sup> This directive defined common rules for the gradual liberalization of the electricity industry with the objective of establishing one common European market. It imposed the separation of monopoly elements from potentially competitive segments, so that controllers of the monopoly part (mainly the network) should not be able to abuse their position in the market, i.e. execute the so-called *market power*.

The market opening prescribed rules upon member countries according to a timetable that allowed each country to define its own pace of market liberalization, somewhere between

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<sup>14</sup> Note that in auction markets the supply and demand curves are stepwise functions. In some cases there may be more than one intersection point. Specific regulations regarding interpolation of volumes between submitted price steps must be defined. See, e.g., Meeus *et al.* (2004).

<sup>15</sup> Directive on Common Rules for the Internal Market in Electricity 96/92/EC, published in the Official Journal L 27/20 on January 30, 1997. See also the Second Report to the Council and the European Parliament on Harmonization Requirements, <http://europa.eu.int>.

the European Commission minimum requirements and full immediate opening. Introducing competition into the EU markets was expected to result in increased energy efficiency and lower prices for consumers.

Despite recent reforms,<sup>16</sup> cross-border transactions still are a major bottleneck in the development of the common EU electricity market. Nevertheless, considerable commercial exchanges of electricity do take place between different markets. One indication for the ongoing regional and European integration is the convergence of wholesale prices between adjacent areas.

### *Spain and the Iberian Market*

With strong national political support, Spain was the first continental country to create an organized market for electricity. In 1997, the Electric Sector Act and Royal Decree 2019/97, created *Compania Operadora del Mercado Español de Electricidad (OMEL)* to manage and run the organized electricity market. OMEL is officially called a power exchange; however, it is a hybrid solution as the employed capacity payments are characteristic for a power pool.

The Spanish electricity market began operation in January 1998, with day-ahead trading. It is a voluntary market, but in practice bilateral trade is discouraged because capacity payments are employed exclusively at OMEL. Moreover, distributors have the obligation to buy all their energy needs at the 'exchange'. Hence, the market liquidity, measured as the percentage of energy traded relative to total demand, is very high and amounts to approximately 80% (OMEL data for 2002–2004).

The Spanish market is widely isolated from the rest of Europe due to limited international transmission capacity, however preparations are under way to establish an integrated Spanish and Portuguese market for electricity (MIBEL). Market opening is planned for mid-2006. OMEL has already changed its name to *Operador del Mercado Ibérico de Energía – Polo Español (OMIE, Operator of the Iberian Market – Spanish Branch)* and will be in charge of managing the MIBEL day-ahead market. The common pool will be a voluntary day-ahead market, and a forward market (for physical contracts initially and later for financial ones) will also be created. Bilateral contracts will be allowed either within each country or across the interconnectors.

Despite initial optimism, the Spanish power sector liberalization is currently conceived as a failure. Two primary reasons brought up are the oligopolistic industrial structure and multiple regulatory flaws. Interestingly, the structure changed in a series of mergers just prior to market opening. By 1998, the two major companies, Endesa and Iberdrola, generated 82% of the total Spanish production and supplied 80% of the demand. Two other vertically integrated companies basically completed the generation stack. Recently some changes in the structure and ownership have taken place (including new entrants) and the situation is gradually improving.

However, the regulatory flaws have accumulated over the years, culminating in 2003, when the increasing electricity wholesale prices resulted in a tariff deficit and yielded negative (!) stranded costs. One of the major regulatory shortcomings is the current mechanism of capacity payments. First, it does not provide generators with an incentive to be available and to produce electricity when there is higher demand. If a generator is unavailable in a day when there is not

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<sup>16</sup> Including the Cross-Border Regulation No. 1228/2003, published in the Official Journal L 176/1 on July 15, 2003, and the second EU Internal Electricity Market Directive 2003/54/EC, published in the Official Journal L 176/37 on July 15, 2003.

enough supply in the system to cover the demand, it just loses the capacity payment for that day. Annually, a single day does not make much of a difference. Second, it does not guarantee that there will be enough installed capacity to meet demand at all times. A recent White Paper by Pérez-Arriaga *et al.* (2005) addresses these and other deficiencies of the Spanish power system. It also proposes a regulatory reform, including running an auction market for additional capacity in case the capacity payments themselves fail to attract enough investment.

### Germany

The German market is the largest (excluding Russia) European market, representing more than 22% of the consumption in continental Europe (UCTE 2005). Unlike most Member States, Germany had no independent regulator, leaving the federal Cartel Office to act as a *de facto* regulator. The German regulatory framework was established by the Energy Sector Law of April 1998. Full market opening, in the sense that all end-users could choose their retailer, became a reality in late 1999. The German liberalization process, however, had two controversial points.

First, it did not restrict vertical integration. Only the minimal EU requirements on unbundling were initially implemented but, even worse, these requirements were not respected in practice. When the German electricity market was liberalized, there were eight major electricity companies. By 2001, mergers and acquisitions reduced this number to four: RWE, E.ON, Vattenfall Europe and EnBW. The capacity share of these four companies increased to 90% of total German generation. As in Britain (but more rapidly), the sector evolved into a consolidated vertical business model. While this structure may be convenient for regulators, it of course does not foster competition.

Second, in contrast to the rest of Europe, negotiated third-party access (nTPA) to the network was implemented. It relied on a negotiated arrangement of network access within the sector, while *ex post* control of possible abuse was left to the Cartel Office. This approach failed in practice. Most importantly, the nTPA led to a margin squeeze, i.e. to low profit margins in generation and retail. Consequently, several initially successful retailers went bankrupt and by 2004 only Yello (a subsidiary of EnBW) survived. The government was not eager to admit the failure, but in late 2004 generally approved the shift to regulated TPA.

Until mid-2000, electricity was traded only on a bilateral basis. As in most other electricity wholesale markets, the majority of deals in Germany are still done on an OTC basis. However, volumes of the exchange traded products have been increasing constantly over the last years (see Table 1.2). In June 2000, the Leipzig Power Exchange (LPX) was launched and backed by Nord Pool. In August 2000, the European Energy Exchange (EEX), based in Frankfurt/aM, was launched as an initiative of the German futures exchange EUREX. In 2002, the LPX and EEX merged and created a single European Energy Exchange (EEX), located in Leipzig.

EEX operates a day-ahead auction market with hourly (for each hour of the next day) and block (daily base load, daily peak load, weekend base load) products. The market clearing price (MCP) describes the equilibrium price determined in the hourly uniform-price auction of the electricity spot market. Prices of block contracts are also established during continuous trading. Electricity can be delivered into any of the five TSO zones. In the case of no congestion, only one market price prevails.

In parallel to the spot market, the exchange operates a futures market where contracts can be traded for delivery up to six years in advance. The contracts include cash-settled Phelix



Base/Peak index futures and options and physically settled German, French and Dutch futures. The daily Phelix Base index (Physical Electricity Index) is the daily mean system price for electricity traded on the spot market, computed as the arithmetic average of the 24-hourly MCP. The Phelix Peak index is the arithmetic average of the hourly MCP for peak hours (8 a.m. – 8 p.m., i.e. hours<sup>17</sup> #9 till #20). Both indices are calculated for all 365 days of the year. EEX also offers OTC clearing services and in 2005 introduced spot and futures contracts for EU ETS CO<sub>2</sub> emissions allowances. The latter enterprise has been highly successful and EEX is currently the largest organized market for carbon dioxide allowances.

The quoted prices benefit from high credibility backed by the large number of market participants (currently over 140; more than half of those are from outside Germany) and the transparency of the price formation process. The EEX prices are the benchmark for the entire market including OTC wholesale and retail business. Trading volumes on the EEX have been continually rising and in 2005 reached a total (day-ahead, derivatives and OTC clearing) volume of 603 TWh (see Table 1.2). In 2004 the day-ahead volume amounted to approximately 11% of German electricity consumption.

### *Poland*

The electricity markets in eastern Europe are still under development. Although the liberalization of these markets is not as advanced as in most of the EU-15 countries, considerable progress has been made and a lot of efforts have been put into the development of competitive markets. However, interconnector capacity and regulatory barriers still exist.

With an annual consumption of about 130 TWh, Poland is by far the largest power market in Eastern Europe. About 40% of the traded volumes are covered by the long-term Power Purchasing Agreements (see Section 1.2.4). They were entered into before the start of the liberalization process and currently comprise an obstacle for faster market development. Another 45% of electricity is purchased through bilateral agreements and the rest amounts for the balancing market, the Polish Power Exchange (PolPX) and the electronic trading platforms.

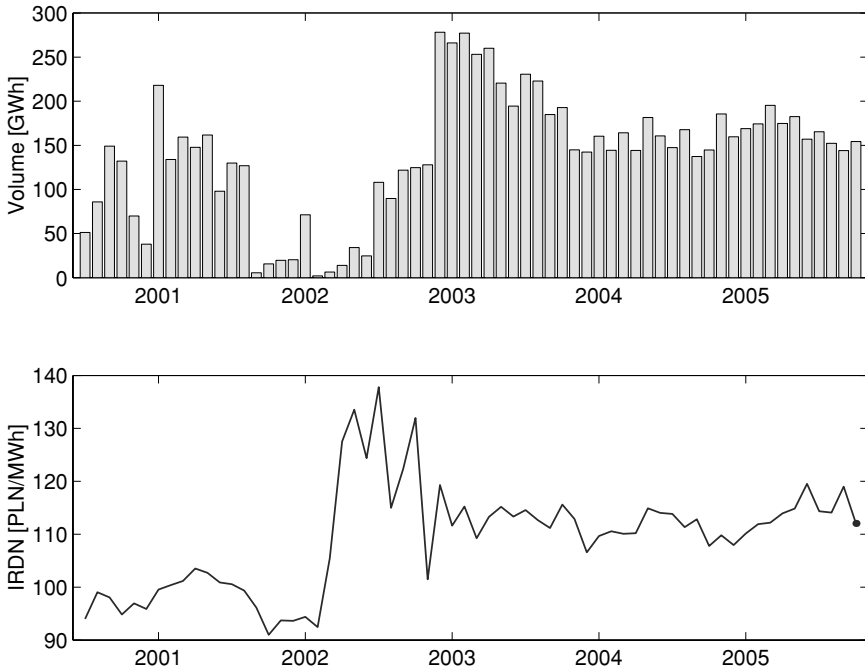
In the past, Poland was a member of the Council for Mutual Economic Aid (CMEA) where it played the role of a coal supplier for other countries of that organization. Costs of coal mining were subsidized by the state in order to ensure low prices on the domestic market. Therefore, production costs in the electricity and heat generating industry were lower than costs of coal extraction. The Polish electricity sector is still heavily reliant on coal-fired capacity, with hard and brown coal accounting for more than 95% of its generation.

The liberalization in Poland began in 1997 with the passing of the Energy Law Act to meet the requirements for EU membership. This law defined principles for shaping the energy policy, including providing customers with a non-discriminatory access to the grid. The Polish Power Exchange (PolPX; Towarowa Giełda Energii SA) was established in December 1999 as an initiative of the Ministry of Treasury by a group of power-producing and energy-trading companies.

The day-ahead market began operation in July 2000. In the beginning, hourly energy trade in PolPX was not consistent with the monthly balancing market operated by the TSO. This resulted in a number of disputes about how to settle the power exchange's hourly transactions

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<sup>17</sup> Hour #9 does not mean 9 a.m. but the interval 8 a.m. to 9 a.m.; i.e. hour #1 is the interval 12 p.m. to 1 a.m.



**Figure 1.4** Monthly statistics for the Polish Power Exchange (July 2000 – October 2005). *Top panel:* Monthly total volumes for day-ahead transactions. Clearly the exchange has had its ups and downs. The most dramatic changes were caused by the launch of the balancing market (September 2001), introduction of the electricity tax (March 2002), debut of the two-price (buyer's and seller's) system on the balancing market (July 2002) and the supply deficit during the second half of 2002. *Bottom panel:* Respective mean monthly values of the IRDN (day-ahead) index

in the balancing market's monthly settlement. When the TSO launched the hourly balancing market in September 2001, the power exchange's trade volumes dramatically dropped (see Figure 1.4). A few months later, the exchange-traded volumes suffered another blow when the electricity tax was introduced. With the debut of the two-price (buyer's and seller's) system on the balancing market, PolPX trading picked up again. It reached an all-time high in December 2002.

In late 2003 the volumes decreased due to the consolidation process among the state-owned distributors and generators and the resulting reduction in the number of participants. They have stayed at this relatively low level since then. The reasons for such a small turnover at PolPX are not clear. Experts indicate several sources, including inappropriate structure, potential for conflict of interest and high charges. Despite the relatively low liquidity, the IRDN index of the day-ahead market is considered as an indicator for the Polish spot electricity market. It is a volume-weighted daily average price for the 24 hourly delivery periods.

Apart from the Polish Power Exchange, a number of electronic trading platforms have appeared. The most successful of these is POEE (Platforma Obrotu Energią Elektryczną), which is a subsidiary of the Bełchatów power plant. POEE started day-ahead trading in late 2002. Since then the platform has developed and currently has an annual turnover just below

1 TWh, which is roughly half the volume traded at PolPX. Both, PolPX and POEE offer long-term contracts (physical and financial futures) but the trading is very scarce.

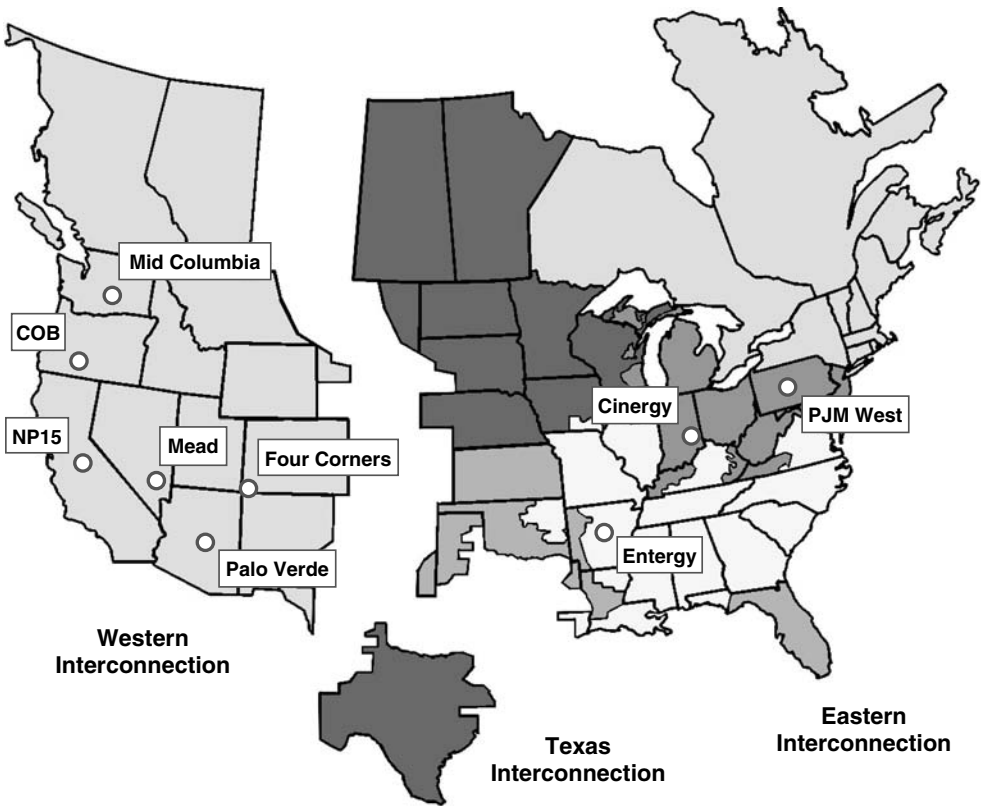
## 1.4 NORTH AMERICA

The 1978 Public Utilities Regulatory Policies Act (PURPA) and Energy Policy Act (EPAct) enacted in 1992 initiated US deregulation from a collection of regulated, regional monopolies to a competitive market of independent power producers and distributors. The US power sector is composed of electric utilities (known also as *wired companies*) whose rate schedules are regulated, as well as non-utilities that offer market-based rates. The majority of non-utilities, independent power producers (IPP) and combined heat and power plants (CHP), maintain the capability to generate electricity but are not generally aligned with distribution facilities. There are approximately 2800 IPP and CHP and over 3100 electric utilities in the USA (EIA 2004a). Most utilities are exclusively distribution utilities that are owned by municipals.

The US power system has evolved into three major networks, or power grids: Eastern Interconnected System (roughly covering the Eastern and Central time zones), Western Interconnected System (Mountain and Pacific time zones) and the Texas Interconnected System. These three systems account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. Utilities within each power grid coordinate operations and buy and sell power among themselves. Reliability planning and coordination is conducted by the North American Electric Reliability Council (NERC) and its eight regional councils (six of which comprise the Eastern Interconnection). Electricity flows over all available paths of the transmission system to reach customers. The major trading hubs in the USA are California North-Path 15 (NP15), California–Oregon Border (COB), Cinergy (Ohio, Indiana), Entergy (Arkansas), Four Corners (Utah, Colorado, New Mexico, Arizona), Mead (Nevada), Mid Columbia (Washington), Palo Verde (Arizona) and PJM (Pennsylvania, New Jersey, Maryland), see Figure 1.5.

For the majority of hubs, an independent system operator (ISO) and a competitive market, have failed to develop; rather, a combination of traditional tariff-based utility pricing, wholesale price matching, bilateral purchases and sales contracts is used. Only in New England, New York, Midwest, the PJM Interconnection and California, a tiered trading structure consisting of a day-ahead and/or hour-ahead market and a real-time balancing market, was designed to ensure that market performance would match the grid's reliability requirements. Moreover, in the face of the turmoil, started with the price run-ups in California beginning in mid-2000, and continued with Enron's collapse in late 2001 and the most extensive blackout in North American history in August 2003, most states have decided to either postpone their deregulation efforts or have stopped considering adopting it at all. Although the volume of the wholesale electricity trading in the existing markets has been growing rapidly in the USA, the majority of the volume is traded via bilateral contracts with and without brokerage.

In Canada, power industry structures and policies vary considerably across provinces. Each province has a separate regulator. Only two provincial governments, Alberta and Ontario, have established markets characterized by wholesale and retail unbundling with an independent system operator (ISO), that sets and administers policies for grid interconnection, transmission planning and real-time market operation (see Section 1.4.3). The remaining provinces are largely characterized by vertically integrated, provincially owned utilities, which offer bundled services at regulated rates to consumers.



**Figure 1.5** Three major networks of the North American power system. The main trading hubs are indicated by circles. Shades of gray denote NERC's regional councils (eight as of June 2006)

### 1.4.1 PJM Interconnection

The PJM (Pennsylvania–New Jersey–Maryland) Interconnection is the world's largest competitive wholesale electricity market. Similar to Nord Pool, PJM provides an interesting example of market design where organized markets and transmission pricing are integrated. PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. As of today it serves over 50 million people and has more than 350 market participants.

PJM combines the role of a power exchange, a clearing house and a system operator. It operates several markets, although different in detail: two generating capacity markets (daily and longterm), two energy markets (day-ahead and realtime), a financial transmission entitlements market and an ancillary services market.

PJM started operations in 1997. At that time the market provided a single price for the entire PJM region. The single price system proved quickly to be problematic as it was unable to reflect adequately locational value of energy throughout the market related to transmission constraints. For this reason, in April 1998, PJM switched from a single price system to a nodal<sup>18</sup>

<sup>18</sup> PJM provides prices for approximately 2000 locations (see <http://www.pjm.com>).

price system with market clearing prices and a year later to nodal, market clearing prices based on competitive offers (locational marginal pricing, LMP), which reflects the underlying cost of the energy and the marginal cost of transmission congestion. PJM started the day-ahead market in June 2000.

In order to allow financial hedging against price differences between locations, since 1999 the LMP system has been accompanied by a system of transmission rights called *fixed transmission rights* (FTR). FTR entitle the holder to receive compensation for transmission congestion charges that arise from locational differences in the hourly locational market prices (LMP) resulting from the dispatch of generators out of merit in order to relieve congestion. FTR do not represent a right to the physical delivery of power, but they do ensure that access is financially firm, i.e. they represent a financial hedge against the ex-post calculated locational prices.

### 1.4.2 California and the Electricity Crisis

California was the first US state to restructure its electricity market, which started at the beginning of 1998.<sup>19</sup> The process of designing the details of California's wholesale and retail market institutions was extremely contentious. In the end, the ultimate structure represented a series of compromises made by design committees, including interest group representatives. The design required creation of an independent system operator (CAISO) and a power exchange.

The California Power Exchange (CalPX) started operations in April 1998. It conducted daily auctions to allow trading of electricity in the day-ahead and hour-ahead markets. CalPX accepted demand and generation simple bids (price-quantity) from its participants, determined the market clearing price (MCP) at which energy was bought and sold and submitted balanced demand and supply schedules for successful bidders to the system operator. It also submitted bids for ancillary services, real-time balancing and congestion management. It was an energy only market with no capacity payments.

CalPX was a voluntary market, however, the major Californian utilities were committed to sell and buy only through CalPX for the first four years of operation, until mid-2002. This rule was a fundamental flaw in the market design. It exposed the utilities to enormous risk. On one hand, their retail revenues were fixed at the regulated rates; the utilities did not receive any additional compensation in the event wholesale prices exceeded the regulated rates. On the other, they were barred from hedging by purchasing power in advance of the day-ahead market. This restriction made the market vulnerable to manipulation. For disaster to strike, all that was needed was a period of tight supply.

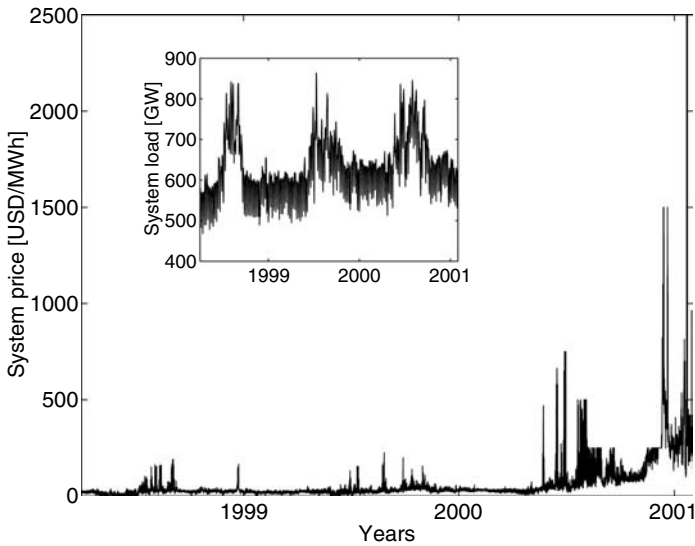
In mid-May 2000 wholesale electricity prices began to rise above historical peak levels (see Figure 1.6). The prices prevailing between June and September 2000 were much higher than the fixed retail price that the utilities were permitted to charge for retail service. Two utilities<sup>20</sup> (Southern California Edison, SCE, and Pacific Gas & Electric, PG&E) began to lose a lot of money: the losses accumulated fast when the utilities were buying at 120 and selling at 60–65 USD/MWh!

Why did wholesale prices rise so quickly and dramatically above projected levels? There are five primary interdependent factors (Joskow 2001): (i) rising natural gas prices, (ii) an increase

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<sup>19</sup> PJM, which is the world's oldest centralized dispatched network, started its restructuring at the beginning of 1999.

<sup>20</sup> The retail prices of the third large utility – San Diego Gas and Electric (SDG&E) – had been deregulated at the beginning of 2000.



**Figure 1.6** Hourly system spot price at the California Power Exchange (CalPX) from the opening of the exchange (April 1, 1998) until the collapse of the market (January 31, 2001). The escalation of prices since mid-2000 and the imposed price caps (successively set at 750, 500, 250, etc. USD/MWh) are clearly visible. The electricity demand in California (represented in the inset by the daily system-wide load) exhibited only a moderate increase in this period and by itself would not lead to the crisis

in electricity demand in California (see Figure 1.6), (iii) reduced imports from other states, (iv) rising prices for  $\text{NO}_x$  emissions credits and (v) *market power* problems.

None of the factors alone would lead to the crisis, however, a coincidence of all five factors had a tremendous impact on the market. Prices in California increased by 500% between the second half of 1999 and the second half of 2000. For the first four weeks of 2001, wholesale spot prices averaged over 300 USD/MWh, 10 times what they were in 1998 and 1999. Some customers were required involuntarily to curtail electricity consumption in response to supply shortages. Electricity supply emergencies were in effect for most of the winter and spring of 2001, and there were several days of rolling blackouts.

California's two largest utilities, PG&E and SCE, became insolvent in January 2001 and stopped paying their bills for power and certain other financial obligations. PG&E declared bankruptcy in April 2001. The California Power Exchange stopped operating at the end of January 2001 and subsequently went bankrupt, eliminating a large organized and transparent day-ahead market for electricity. It was the first bankruptcy of a power exchange in history.

In post-crisis California the ISO operates a small fraction (less than 10%) of the total wholesale electricity marketplace. It runs the ancillary services market to maintain operating reserves, the transmission market to efficiently allocate transmission space and the real-time imbalance market to match supply with demand.

### 1.4.3 Alberta and Ontario

Alberta deregulated its electric power industry in the mid-1990s, establishing open transmission access and a competitive market. Since January 1, 1996, all electricity has been sold into the

Power Pool of Alberta. Retail competition was introduced in January 2001, with consumers free to purchase their electricity from any licenced retailer. To facilitate hedging, the Alberta Watt Exchange (Watt-Ex) was established and in January of 2001 commenced trading forward electricity contracts deliverable into the Power Pool of Alberta.<sup>21</sup> The new Electric Utilities Act of 2003 established the Alberta Electric System Operator (AESO) to carry out the functions of the former Power Pool of Alberta. The AESO's web-based Energy Trading System (ETS) enables real-time trading in the form of a two-sided auction. The *market price* is calculated as the time-weighted average of the 60 one-minute *system marginal prices* (SMP).

For almost a century, the vast bulk of Ontario's electricity was produced by Ontario Hydro and sold to consumers through local municipal utilities. As a first step toward a competitive market, the Ontario Electricity Act of 1998 re-organized Ontario Hydro into a number of successor companies including the Independent Electricity System Operator (IESO; formerly Independent Electricity Market Operator, IMO). IESO is responsible for the safe and reliable operation of Ontario's electrical system and, since May 2002, operates the real-time wholesale market. The *market clearing price* (MCP) is set for each five-minute interval, based on bids and offers into the market. In addition, each hour a calculation is performed to determine the *hourly Ontario energy price* (HOEP) by using the average of the five-minute prices. HOEP is used as the wholesale price for electricity for non-dispatchable generators and non-dispatchable loads.

Ontario introduced privatization legislation in 1998 and deregulation began there in 2002. However, the process slowed down during California's energy crisis. To reduce the impact of summer 2002 price spikes on consumers, the Ontario government capped retail prices at a price well below the cost of power. Consequently, the government had to pay the difference between the wholesale cost of electricity and the frozen retail price. This resulted in a need for substantial government subsidies and a reluctance of investors to move into the Ontario market.

## 1.5 AUSTRALIA AND NEW ZEALAND

Prior to 1997, electricity supply in Australia was provided by vertically integrated publicly owned state utilities with little interstate grid connections or trade. The Australian National Electricity Market (NEM) began operating as a wholesale market for the supply of electricity to retailers and end-users in Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia in December 1998. In 2005 Tasmania joined the NEM as a sixth region.

Exchange between electricity producers and electricity consumers is facilitated through a pool where the output from all generators is aggregated and scheduled to meet forecasted demand. The NEM Management Company (NEMMCO) manages the pool according to the provisions of National Electricity Law and in conjunction with market participants and regulatory agencies.

Wholesale trading is conducted as a real-time market where supply and demand are instantaneously matched through a centrally coordinated dispatch process. Generators submit offers every five minutes of every day. From all offers submitted, NEMMCO's systems determine the generators required to produce electricity based on the principle of meeting prevailing demand in the most cost-efficient way. NEMMCO then dispatches these generators into production. A dispatch price is determined every five minutes, and six dispatch prices are averaged every half-hour to determine the *spot price* for each trading interval for each of the regions. NEMMCO

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<sup>21</sup> In 2005 Watt-Ex introduced forward electricity swaps (see <http://www.watt-ex.com>).

uses the spot price as the basis for the settlement of financial transactions for all energy traded in the NEM.

The New Zealand Electricity Market (NZEM) was established on October 1, 1996; however, it did not become a truly competitive market until April 1999. Since the market's inception, the bulk of electricity generated in New Zealand is sold through the NZEM. The wholesale real-time market for electricity is administered by M-co on behalf of the New Zealand Electricity Commission. The main participants are the seven generator/retailers who trade at 244 nodes across the transmission grid. Prices and quantities are determined half-hourly at each node. The price is set in a uniform price auction according to the cost of providing the electricity, which incorporates locational variations and the cost of providing reserve. These locational variations can happen because of transmission system outages, transmission losses and capacity constraints.

Australia and New Zealand are particularly interesting in that they operate 'energy only' markets. In such markets the wholesale electricity price provides compensation for both variable and fixed costs. Australian experience indicates that the price spikes can be a good enough motivation for new investments. This can be best illustrated by the recent changes in South Australia.

The peak demand in South Australia has been steadily rising in the last years, mostly due to the increasing popularity of air-conditioning. This created a tight supply–demand balance, already at the inception of the electricity market. The NEM spot prices for South Australia several times reached the 5000 AUD/MWh price cap during peak hours in the summers of 1999–2000. This raised a lot of political concerns and public debates but the South Australian government decided not to intervene directly. Instead it decided to raise the price cap to 10 000 AUD/MWh, giving investors a clear signal of stability and confidence in the market. Indeed the investor response effectively overcame the tightness of supply and demand. Installed capacity increased by nearly 50% in the period 1998–2003, almost half of it being open cycle gas turbines (OCGT) for peaking purposes.

## 1.6 SUMMARY

The complexity of today's electricity markets is enormous. The economic and technical characteristics of the power systems, as well as the awareness and commitment of the regulatory and political bodies add to the complexity and jointly constitute a platform from which a market design is drawn. Whether it will be a successful design is not known up-front. Clearly there is not one single best market model. There are examples of prosperous power pools and power exchanges, of 'energy only' markets and markets with capacity payment systems. However, no matter what are the actual regulations there is one common feature of all successful markets: a formal price quotation mechanism. It adds transparency to the market and is the source of vital information for the generators, utilities, traders and investors alike.

## 1.7 FURTHER READING

- Market design and power market economics are reviewed in Boisseleau (2004), Bower and Bunn (2000), Chao and Huntington (1999), Cramton (2003), EIA (2004b), Hunt (2002), IEA (2001), IEA (2005a), Kirschen and Strbac (2004), Mielczarski (2006), Mielczarski and Michalik (1998), Rothwell and Gómez (2003), Sioshansi and Pfaffenberger (2006), Stoff (2002) and Zhou (2003).



- Cramton and Stoft (2005), Gallagher (2005), Hogan (2005) and Meeusen and Potter (2005) discuss the pros and cons of capacity payments, capacity markets and 'energy only' markets.
- Blackouts and transmission system security in competitive electricity markets are discussed in Bialek (2004) and IEA (2005b).
- Borenstein *et al.* (1999) and Bunn and Martoccia (2005) discuss the problem of market power in the power markets.
- A good starting point for CO<sub>2</sub> emissions allowances data and information is <http://www.pointcarbon.com>.
- Bunn (2006) reviews the British experience of electricity liberalization.
- See <http://www.nordpool.no> for price and volume data, market statistics and Nord Pool's annual reports. Simonsen (2005), Simonsen *et al.* (2004) and Vogstad (2004) provide additional information and analyses.
- Pérez-Arriaga (2006) argues that the liberalization of the Spanish power sector was a failure. The original White Paper, Pérez-Arriaga *et al.* (2005), is available from <http://www6.mityc.es/energia/archivos/LibroBlanco.pdf>.
- See Brunekreeft and Tweleemann (2005) for a recent review of the German market. The whole issue (volume 26) of the *Energy Journal* is devoted to the liberalization of European electricity markets.
- Marecki *et al.* (2001) discuss the Polish energy policy in the period of emerging energy markets. Malko (2005) gives a more recent account. Mielczarski (2002) reviews the development of the Polish electricity market.
- See Makhholm *et al.* (2006) and Rose and Meeusen (2005) for a recent performance review of the US electricity markets.
- Cramton (2003) and Joskow (2001) discuss California's electricity crisis.
- Canada's energy policy is summarized in IEA (2004).
- See <http://www.nemmo.com.au> and NEMMCO (2005) for details on history, system conditions, market structure, ownership, concentration and types of bidding systems in Australia.

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