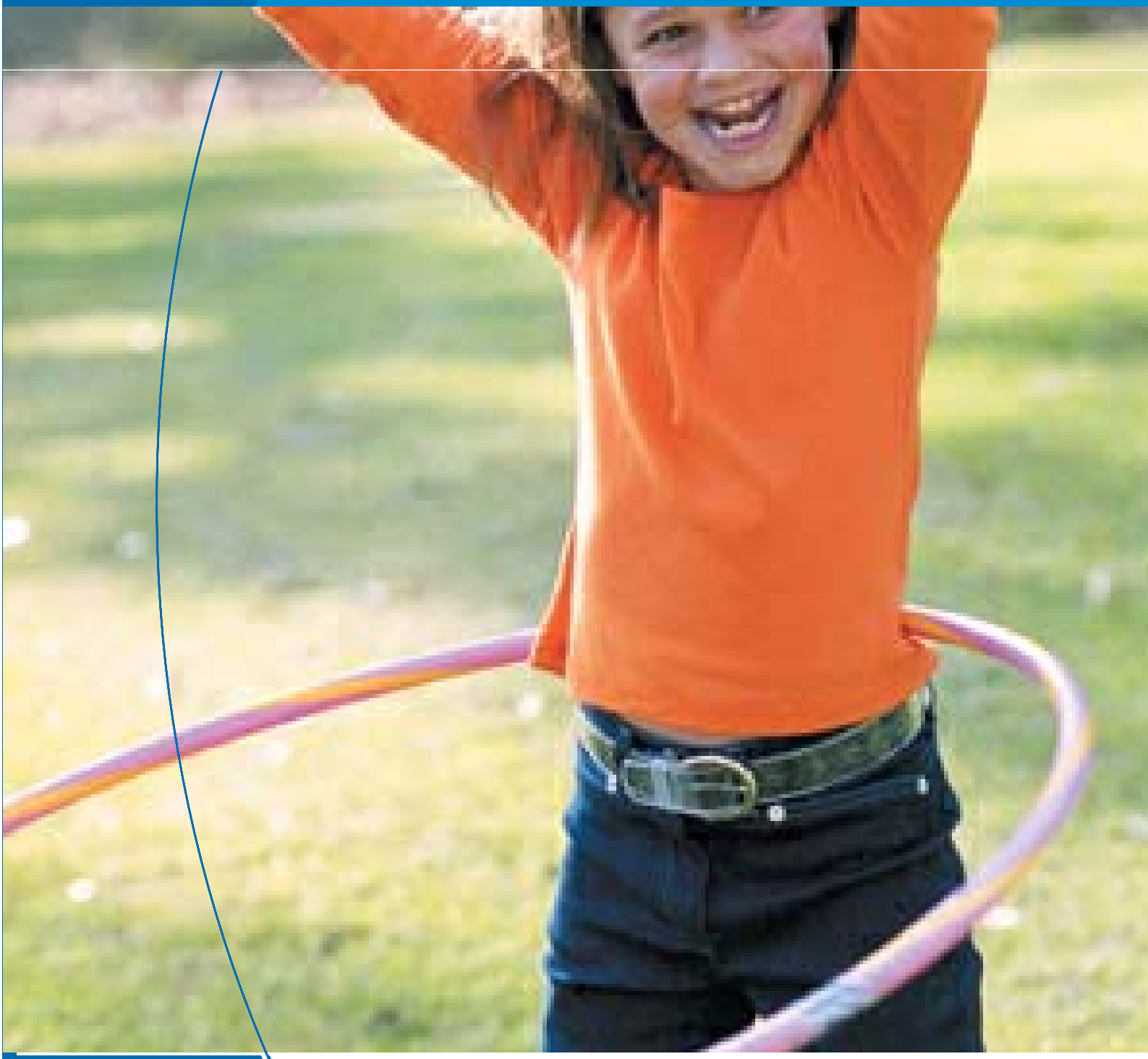
ELECTRICITY MARKET REPORT 2003

PART 1: GENERAL KEY THEMES AND ISSUES



VATTENFALL

Electricity Market Glossary

CHP plant	Combined heat and power plant. Plant which produces both electricity and heat in the same process.
Deregulation	Removal of monopoly rights and obligations in order to open up for competition. Here used as a synonym for liberalisation.
DSO	Distribution system operator. Responsible for operating, ensuring the maintenance of and developing the distribution system in a given area.
EEX	European Energy Exchange, the German power exchange. Headquarter in Leipzig.
Ex-ante tariff regulation	Approval of tariffs prior to implementation.
Ex-post tariff regulation	Tariffs amended after implementation if deemed necessary.
Generation/production	Production of electricity. The words are used synonymously.
Green certificate	A tradable certificate issued for renewable energy. In Sweden called electricity certificate.
GWh	Gigawatt-hour – 1 000 000 kWh. Amount consumed by 40 small houses in one year.
kWh	Kilowatt-hour – Energy unit. Amount of energy produced when running 1 kW of capacity for 1 hour. Amount required to run an 11-watt low-energy bulb for almost four days.
Legal unbundling	Legal separation of transmission/distribution from other activities (generation/supply).
Lignite	Brown coal.
LPX	Leipzig Power Exchange. Merged with EEX in 2002.
MWh	Megawatt-hour – 1 000 kWh. Amount required to heat a small house in Sweden for a couple of weeks.
Negotiated third party access (NTPA)	Access to the network granted on the basis of bilateral negotiations between grid owner and grid user.
Nord Pool	The Nordic power exchange.
OTC	"Over the Counter". Trading of physical and financial contracts in parallel to the organised exchanges.
PF	Pulverised fuel. Modern coal fired technology.
POLPX	The Polish Power Exchange; Towarowa Gielda Energii.
Regulated third party access (RTPA)	Access to the network granted on the basis of published and regulated tariffs for the use of the network.
Regulator	Competent authority that supervises the market to ensure effective competition and fair pricing.
Retailer	Firm at the end of the distribution chain, which normally buys a product from a wholesaler in order to sell it to the final consumer.
Spot market	Short-term physical trading in electricity on an exchange.
TSO	Transmission system operator. Responsible for operating, ensuring the maintenance of and developing the transmission system in a given area.
TWh	Terawatt-hour – 1 000 000 000 kWh.
Unbundling	Separation of the transmission/distribution system interests from the other interests of a company.
Value chain	Generation, transmission, distribution and sale of electricity. Applicable to both trading and transport of electricity.
Wholesaler	Intermediate in the distribution chain that buys the product in bulk from the producer and sells it in smaller quantities to distributors or retailers.

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Foreword

Last year, Vattenfall published its very first Electricity Market Report based on a Nordic outlook. The Electricity Market Report 2003 is built on descriptions of Vattenfall's home markets, i.e. Germany, Poland and the Nordic region.

The ambition is to give a broad description of the main features of how these markets work and also to place them in a European context. As we at Vattenfall understand it, the general purpose of the deregulation of electricity supply is to create an open electricity market and to improve efficiency by employing developed market instruments. However, the actual workings of the electricity market and how supply and demand interact to create price(s) are still fairly unknown outside the electricity industry. As a result, the credibility and trustworthiness of the electricity market as well as of its players are sometimes questioned.

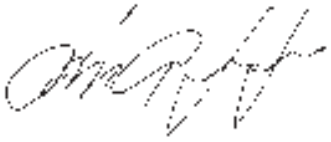
It is Vattenfall's firm belief that our best contribution to building trust in the market is by being open and share our knowledge and understanding of the present state of our home markets, the overriding development of the internal electricity market in Europe and how we judge its future development. Our hope and conviction is that we thereby can improve the understanding of the electricity markets in a wider audience and contribute to building a good basis for reasonable expectations.

The perspective in the description is naturally Vattenfall's but I want to underline that we are not aiming here to market our products or promote our actions. Our ambition is to give our version of the market development as objectively and neutrally as possible.

The Electricity Market Report 2003 contains two different parts. Firstly, a part that presents general themes of relevance for the market development seen from a north European perspective, built on market analyses of Vattenfall's core markets, and secondly, a part consisting of three separate descriptions of the Nordic, the German and the Polish markets.

A broad team of more than 30 people from the whole Vattenfall Group has worked together to compile this report. Arne Mogren, Vattenfall Public Affairs, has carried the overall responsibility for this work.

Stockholm, October 2003



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Overview

Public electricity supply has been developing for almost 125 years. It all started around 1880 when Thomas Alva Edison established the very first utility in New York. Electricity soon developed into an essential part of the very backbone of modern society. Light, heat and power were suddenly easily available if and when required. The utilities of Hamburg and Berlin, now part of the Vattenfall Group, were pioneers in Europe in building up the required infrastructure for public electricity supply.

During the past fifteen years, the electricity supply industry has undergone a dramatic wave of change. In Europe, it began in England and Wales where the old monopoly was restructured under a new liberalised regime.

By introducing market mechanisms into electricity supply, higher levels of efficiency and customer orientation were achieved.

Three drivers have since been reshaping European electricity supply. Firstly, deregulation or liberalisation has been introduced, implying not the removal of regulation but the abolishment of de facto or de jure supply monopolies that prevented openness, competition and efficiency. Secondly, market integration over national borders as well as over electricity borders is beginning to take effect. And thirdly, the application of market based return requirements on capital, which in many cases has led to privatisation in combination with market notification.

In the market place, these drivers have resulted in freedom of choice for customers between different ways of combining price and risk as well as between different suppliers; for suppliers and network operators, it has brought with it pressure on costs as well as on prices. This has resulted in lowered margins and strong competition.

For companies in the electricity supply industry the wave of change is creating incentives for consolidation, i.e. growth through mergers and acquisitions to keep up with market expansion. Internationalisation and the application of new business models have added to the restructuring of the industry.

For individual companies, the whole business environment has changed drastically. Ten years ago Vattenfall had all its business activities in Sweden. Today the Vattenfall Group has tripled in size mainly by acquisitions in Germany, Poland and Finland.

The change is also tremendous viewed from the electricity consumer's perspective. In the old world, the price you paid for electricity was a set tariff applied by your supplier. If you were unhappy with the price, your only option were either to make a formal complaint or stop using electricity. Today, the customer is supposed to make an informed and complex choice, by combining the elements of price, risk insurance and supplier.

Even if change has been rapid and widely debated, it will take time before the majority of market players, including customers, fully realise the consequences. Initially, problems may arise but gradually, market players will adapt and make full use of the new possibilities.

The "second electricity revolution" has developed at different speeds in different corners of Europe due to variance in structure, energy sources and political solutions. The trend however is clear – change is happening everywhere, and going in the same general direction towards more competition, more integration, higher levels of efficiency, and higher levels of service quality.

The European Union has from a very early stage played a coordinating role in this development. The first step was a set of minimum rules creating openness in certain respects among still mainly national or in some case regional markets. Gradually, national markets have been made to adopt more and more legislation aiming at opening them up to the full forces of competition and customer choice. All customers will now have guaranteed freedom from the year 2007. Additional steps will follow. National markets will develop into regional markets, and regional markets will stepwise merge into an internal, European electricity market.

In the next step of the development of a European electricity market it will be important to harmonise rules, regulations and market interventions in order to counteract sub-optimisation, a very serious issue in an industry where typical investment cycles are 30 to 40 years long.

The views presented in the 2003 Electricity Market Report are formed from the perspectives of Vattenfall's markets, i.e. the Nordic region, Germany and Poland. Where relevant, a European perspective has been added. The following general conclusions can be drawn:

The liberalised power markets in the countries where Vattenfall is operating are performing well, but capable of improvement.

- EU energy markets are now moving towards free competition.
- In Germany the electricity market is in a transition stage.
- Poland is still in early stages of deregulation.
- The Nordic power markets are performing well at wholesale level but from a customer's perspective there is room for improvement.

Liberalisation and restructuring of EU energy markets will continue.

- Deregulation, integration, consolidation and restructuring are set to continue.
- Management of and access to cross-border transmission links will become increasingly important.
- Price levellisation between countries will continue.

In a deregulated electricity market, the role of network operators changes, and network regulation must satisfy many different interests. Network regulation should support a liberalised electricity market.

Due to fundamental drivers electricity cost may rise in the long run.

- Average prices on wholesale level are to low in relation to what is needed to cover total costs for new capacity.
- Investments in new capacity will only take place if economically profitable.
- There are several factors and circumstances, e.g. CO_2 restrictions, support for renewable energy and more complex permission processes, that in combination may put upward pressure on prices (in relation to current average long term price level at normal levels of precipitation).

Liberalisation has exposed risks that were previously hidden. In a liberalised, competitive market it is natural for prices to fluctuate.

Market players, including customers, have to make active choices regarding hedging. Weather conditions, for example, can give rise to significant price variations. This has been shown in particular in the past year, which has seen the effects on prices of two consecutive dry years in the Nordic market. On the European continent, a very warm and dry summer resulted in similar effects by means of increased electricity consumption for air conditioning purposes in combination with reduced electricity supply as some nuclear reactors had to be shut down because temperatures of the water rose and could therefore not provide enough cooling for maximal output. While certainly extreme, these conditions are within the range of expected market variations, and may very well arise again. Seen over a longer time period, the market should expect, on average, a return to normal price levels, but never rule out the risk of fluctuations due to temporary phenomena.

Electricity supply in Europe was established around the turn from 19th to 20th century and it is at present undergoing a thorough reform driven by market forces. The reform is built on openness and efficiency.

The next step will be a third wave of change. Environmental changes and security of supply issues must be handled in line with the basic functioning of the developing internal electricity market. There is no contradiction between an open and efficient market on the one hand and responsibility issues on the other. Turning back to solutions based on national monopolies does not solve the challenges lying ahead. Looking forward, common solutions based on market principles and harmonisation of rules and regulations will strengthen the common electricity market step by step.

A competitive and efficient electricity supply industry is an important component in a competitive EU 25.

Part 1:
GENERAL KEY THEMES AND ISSUES 2003

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Network regulation should support a liberalized electricity market

Due to fundamental driving forces, electricity costs may rise in the long term

Liberalization has exposed risks that were previously hidden

The liberalised power markets on which Vattenfall operates are performing well, but are capable of improvement

Four criteria determine market efficiency

Efficient, well-functioning, competitive power markets depend on four basic conditions being met, all of which in combination are necessary to create market credibility and trust. These are

- **Customer choice,** i.e. that all consumers are free to choose their supplier, and this condition must be met in legal, commercial and practical terms. It presupposes that there is a clear division between monopoly operations, such as network services, and competitive operations, such as electricity supply.

- **Representative and readily accessible market prices,** which means that there must be a transparent marketplace on which a large number of transactions between anonymous parties take place on a regular and continuous basis. Power quantities traded must also be significant and must constitute a large enough share of total market volume to be considered representative.

- A common set of market **rules and regulations** and market participants jointly taking responsibility for keeping the market performing well. Public trust in the market can be upheld only by the participants acting in reasonable and responsible ways, with perceived genuine intent to uphold and improve market efficiency.

- Effective **market supervision.** Given that liberalization is an ongoing process, the market cannot be expected to work perfectly straight away. Finding the right balance between rules and regulations, consumer interests and the needs of the market players is an ongoing process. Effective market supervision is an essential tool in identifying, evaluating and rectifying market imperfections. It must be specifically adapted to the requirements of the various parts of the value chain.

The EU energy markets are now moving towards free competition

Liberalization of the European energy markets has progressed at different rates in the various countries, and more slowly in the gas market than in the electricity market. Following up on the progress of implementation of the internal electricity and gas markets, the Commission annually updates a benchmarking report that compares the conditions in different Member States, and in the candidate countries in the April 2003 report. The report concludes that there has been some progress in the Member States since 2001 in terms of the general functioning of the electricity market. Germany, Austria and the Netherlands were particularly notable for this. However, some issues still present obstacles:

- Differences in degrees of market liberalization distort competition by allowing some competitors but not others to cross-subsidise.
- Disparities in access tariffs between network operators, which may form a barrier to competition due to the lack of transparency caused by insufficient unbundling and inefficient regulation.
- High level of market power among existing generators, combined with a lack of liquidity in wholesale and balancing markets, which impedes new entrants.
- Insufficient interconnection infrastructure between regions and Member States and, where congestion exists, unsatisfactory methods for allocating scarce capacity.

Figure 1: Current electricity market deregulation status in Member States and Candidate Countries (red shading indicates structures that are negative for the development of an internal market, and green shading indicates structures that are positive for this development).

	Declared market opening (%)	Unbundling: transmission system operator\owner	Unbundling: Distribution system operator	Regulator	Overall network tariffs	Balancing conditions favourable to entry	Biggest three generators share of capacity (%)
Austria	100	Legal	[illegible]	ex-ante	[illegible]	moderate	45
Belgium	[illegible]	Legal	Legal	ex-ante	average	[illegible]	[illegible]
Denmark	100	Legal	Legal	[illegible]	average	favourable	[illegible]
Finland	100	Ownership	[illegible]	ex-post	average	favourable	45
France	54	[illegible]	[illegible]	ex-ante	average	moderate	[illegible]
Germany	100	Legal	[illegible]	[illegible]	[illegible]	moderate	64
Greece	[illegible]	Legal/Mgmt	[illegible]	ex-ante	average	moderate	[illegible]
Ireland	56	Legal/Mgmt	[illegible]	ex-ante	average	moderate	[illegible]
Italy	70	Own/Legal	Legal	ex-ante	average	moderate	69
Lux	[illegible]	[illegible]	[illegible]	ex-ante	[illegible]	[illegible]	n.a.
Neth	[illegible]	Ownership	[illegible]	ex-ante	average	moderate	59
Portugal	[illegible]	Legal	[illegible]	ex-ante	average	moderate	[illegible]
Spain	100	Ownership	Legal	ex-ante	average	favourable	[illegible]
Sweden	100	Ownership	Legal	ex-post	average	favourable	[illegible]
UK	100	Ownership	Legal	ex-ante	average	favourable	36

[1] NTPA=Negotiated third party access

	Declared market opening (%)	Unbundling: transmission system operator\owner	Unbundling: Distribution system operator	Regulator	Overall network tariffs	Balancing conditions favourable to entry	Biggest three generators share of capacity (%)
Estonia	[illegible]	[illegible]	Not examined in this report	ex-ante	not examined in this report	not examined in this report	[illegible]
Latvia	[illegible]	Legal		ex-ante			[illegible]
Lithuania	[illegible]	Legal		ex-ante			[illegible]
Poland	[illegible]	Legal		ex-ante			47
Czech R	[illegible]	Legal		ex-ante			77
Slovakia	[illegible]	Legal		ex-ante			[illegible]
Hungary	[illegible]	[illegible]		unknown			unknown
Slovenia	[illegible]	Legal		ex-ante			[illegible]
Romania	[illegible]	Legal		ex-ante			70
Bulgaria	[illegible]	[illegible]		ex-ante			81
Turkey	[illegible]	Legal		ex-ante			65
Cyprus	[illegible]	[illegible]		ex-ante			[illegible]
Malta	[illegible]	[illegible]		unknown			[illegible]

Source: Second Benchmarking Report on the Implementation of the Internal Electricity and Gas Market (updated report incorporating Candidate Countries), European Commission staff working paper, SEC (2003) 448, 16/04/2003.

In the opinion of Vattenfall, it seems worthwhile to highlight and focus on the areas of deregulation that need improvement in different countries in order to increase market efficiency. However, in some areas, it is not relevant to discuss the market shares of generators in individual countries, since market integration has already progressed so far that markets have become regional rather than national. This is true, for example, in the Nordic area. Seen in a Nordic perspective, the three largest generators (Vattenfall, Fortum and Statkraft) together account for 47 % of production (see figure 3 in Part 2). The fifteen largest generators together account for 81 % of generation.

The benchmarking report concludes that "full opening of the market, combined with appropriate structural measures related to unbundling and regulation, is necessary to deliver consistent benefits to all consumer groups. In particular, it is clear that smaller consumers in markets without full and effective opening of the market cannot benefit from competitive conditions and are consequently likely to suffer in relative terms."

The role of the EU institutions in setting the rules for the development of the European electricity market will continue to grow in importance. The Directives on the Internal Energy Market and the Regulation on Cross Border Exchanges, both adopted 16 June 2003, form the basis for the market.

The electricity market in Germany is in transition

Germany incorporated the Internal Market Directive for Electricity into national law on 29 April 1998 by amending the Energy Industry Act (EnWG) that had originally been promulgated in 1935. As a consequence of liberalization, energy suppliers lost the protection of their respective service territories, a privilege that had previously been contractually guaranteed. Energy suppliers were put under obligation to make their electricity networks available to all power suppliers on a non-discriminatory basis. All customers have since been legally entitled to free choice of their electricity supplier.

THE LEGAL FRAMEWORK OF THE EU ELECTRICITY MARKET

Main provisions of the Directive concerning common rules for the internal market in electricity and The Regulation on conditions for access to the network for cross-border exchanges in electricity

Market opening
All customers should have the right to choose their supplier, non-household customers by 1 July 2004 and households by 1 July 2007.

Unbundling
From 1 July 2004, transmission and distribution operators in all Member States shall separate interests not relating to transmission/distribution from other activities of the company at least in terms of legal form, organization and decision making. Individual Member States may decide to postpone legal unbundling until 2007 and to not apply it to companies serving less than 100 000 customers. If applied, the latter would have effects on the market in countries with many small distribution companies.

Public service obligations
Household customers and small enterprises shall enjoy universal service, i.e. the right to be supplied with electricity at reasonable prices. In or with the bills, the suppliers must specify the contribution of each energy source to the overall electricity generation mix.

Regulatory authorities
Every Member State shall designate a competent body, wholly independent from the interest of the electricity industry, which shall monitor the market and ensure non-discrimination, effective competition and efficient functioning of the market.

Cross-border exchanges in electricity
Fair, cost-reflective, transparent and directly applicable rules shall be introduced with regard to cross-border tariffication and the allocation of available interconnection capacities, in order to ensure effective access to transmission systems for the purpose of cross-border transactions.

The Directive and the Regulation shall be implemented in the EU Member States no later than 1 July 2004.

Germany initially opted for adopting negotiated third party access, a tariff access regime based on voluntary access arrangements between network owners and users.

Although all customers are now able to choose their supplier freely, some observations regarding the remaining scope for improvement of market efficiency seem worth making.
A stringent schedule for legal and functional unbundling of distribution from sales has been defined. Legal and functional unbundling (i.e. the organizational separation of activities within a legal entity) is to be achieved by all Member States from 1 July 2004, unless an individual Member State decides to postpone legal unbundling until 1 July 2007. Transmission companies have already legally unbundled on a voluntary basis. Following deregulation, the number of market participants in Germany has increased with the entry of new competitors. As the market matures and sustainable competitive positions become clearer, it is expected that consolidation will reduce the number of active market participants.

Germany has now decided to change from negotiated third party access to regulated third party access in the near future. Recognition of the fact that the roles of local "tariff pricing authorities" are different in a liberalized market is increasing. Further standardization in supplier switching and in the handling of metering data is under way.

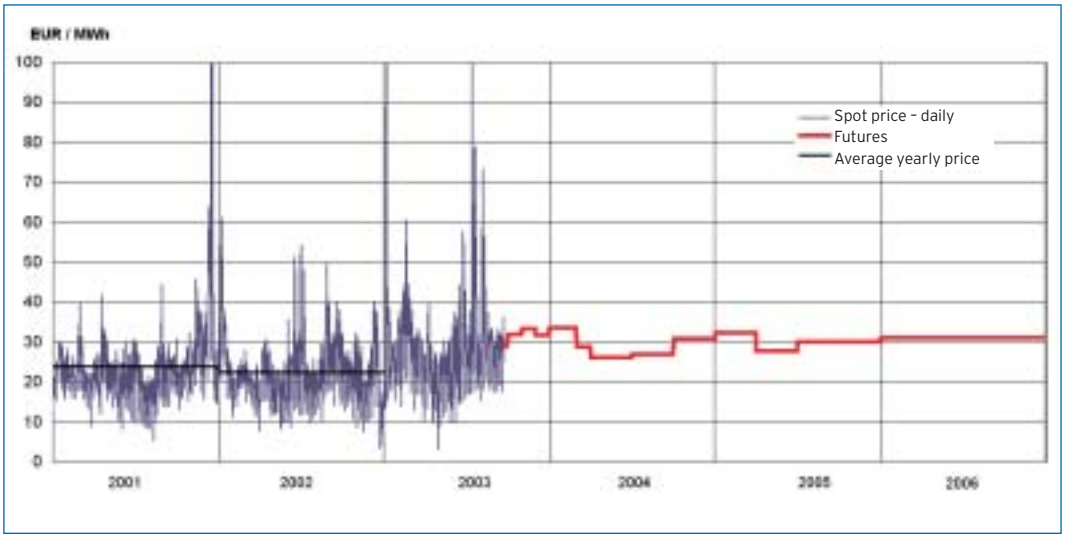
It is expected that when appropriate remedies have been found, this will increase the competition and transparency of the market.

A transparent wholesale market has been established and wholesale prices are increasingly accepted by the power industry as a representative reference. The merger of the two electricity exchanges EEX and LPX (European Energy Exchange and Leipzig Power Exchange) in 2002 has increased transparency and created a strong marketplace. Liquidity in the spot market (EEX) is steadily increasing. Today, 10–12 % of the total underlying physical demand is traded in the spot market.

Total turnover in the forward market is approximately 1500–1800 TWh (OTC plus Exchange, 3 times the underlying consumption).

There are about 100 players in the German wholesale market, and 30 of these are active on a daily basis. The vast majority of the market players have a multitude of hedging pos-

Figure 2: German wholesale market electricity prices 2001–2006.



Source: EEX, 1 October 2003.

sibilities available to them. Pricing to medium sized and large customers has a high correlation with wholesale prices.

The influence of political issues on the energy industry still is, and will continue to be, fairly high. Germany has decided to phase out nuclear power over the next two decades. Political support for green energy (EEC law) has resulted in a high increase in renewable energy systems. Combined heat and power generation has received an economic boost by the CHP law as part of a CO_2 reduction strategy. The German market is described in more detail in part 2.

Poland is still at an early stage of deregulation

The reform of the electricity industry in Poland began in 1997 when the new energy law came into force. The new law has gradually granted groups of customers the right to choose their electricity supplier, starting with electricity-intensive industry. As of 2003, an electricity customer who has a consumption of at least 10 GWh annually qualifies to exercise this right. All electricity customers, including households, will have the right to choose from 2006.

A regulator has been appointed and has been given wide powers to approve tariffs prior to application (ex-ante). "Tariffs are set "cost-plus", with the regulator determining which costs are "justified". Initially, the regulator controlled all prices along the entire value chain, thus removing any incentive towards efficiency improvement or development of competition. Power plants are no longer obliged to submit prices for approval. So the price can be agreed in a bilateral agreement between the power plant and its customer. But 54 % of the electricity produced by the power plants is still sold to PSE, the Polish power grid company, under long-term agreements. PSE used to serve not only as the national grid operator, but also as the single buyer. It still trades in electricity.

Distribution companies can trade and sell electricity, but are obliged to keep separate accounts and to eliminate cross-subsidies. Legal unbundling is not required. The regulator approves electricity and network tariffs for distribution companies prior to publication.

Deregulation has speeded up the economic transformation of the Polish energy sector. Energy companies are becoming more commercially minded and customer-oriented. The grid companies, which operate as natural monopolies, strive for more efficient utilization of their resources and higher transparency of their costs. Other companies that already operate on a competitive market or will soon join the competition, are preparing for market-based pricing.

Cross-subsidies have partially been eliminated. Customers have become more aware of their rights, and are preparing to take advantage of their ability to choose. The process of deregulation needs to be continued in Poland to bring more benefits to the market.

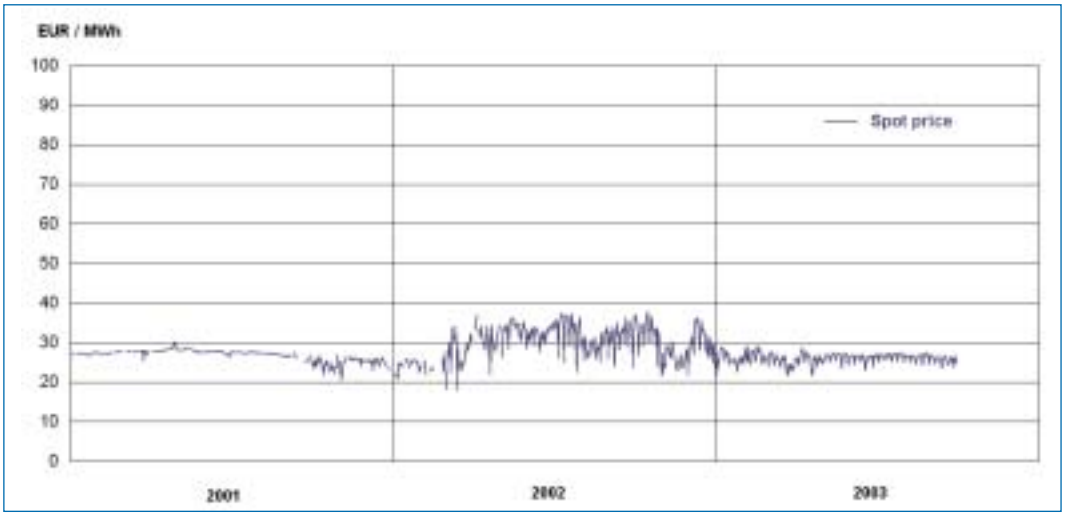
The first steps towards liberalizing the electricity market have been taken. A power exchange (Towarowa Gielda Energii) has been set up and is preparing to handle larger volumes than those currently traded (only 3 % of the physical volume are presently traded on the exchange). It is also preparing to become a part of the European alliance of power exchanges.

In terms of market efficiency achieved, it seems fair to say that Poland still has some way to go. Customer choice will not be achieved before 2006, when all customers will gain the right to switch suppliers. The liquidity of the wholesale market is as yet too low to produce a representative market price. Rules and regulations are still in the process of being formulated, and market participants are in transition from old-world to new-world thinking. The Polish market is described in more detail in part 2.

The Nordic power markets perform well at wholesale level, but from a customer's perspective, there is room for improvement

The Nordic electricity market has been deregulated gradually. A full description of this process is provided in Part 2. In the summer of 2003, the Nordic competition authorities

Figure 3: Polish wholesale market, electricity prices 2001–2003.



Source: Polish Power Exchange; Towarowa Gielda Energii, 1 October 2003. Exchange rate used: EUR/zloty – yearly average according to the Polish Central Bank.

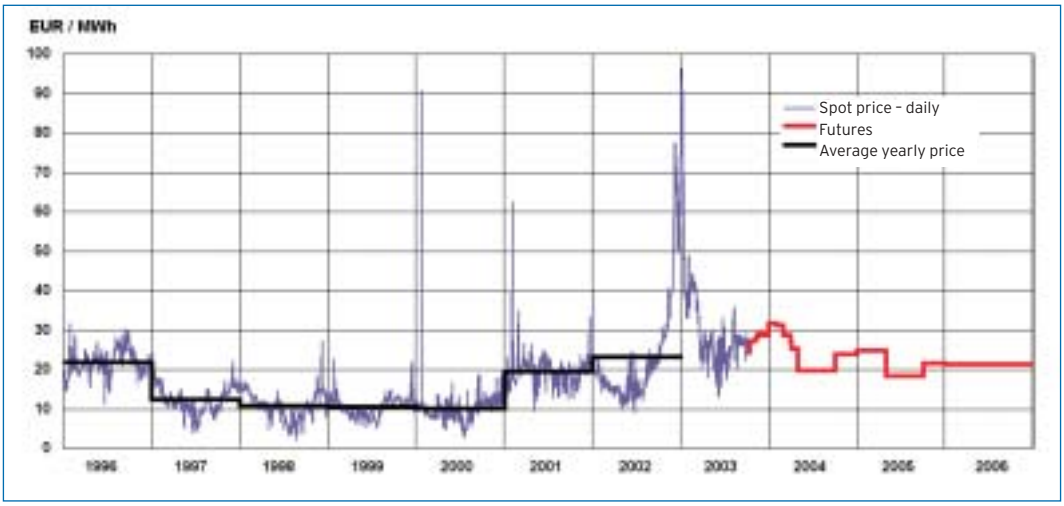
published a report on a study of the competitiveness of the Nordic electricity markets. The overriding conclusion of the report is that the deregulation of the Nordic electricity sector has been largely successful, although a few remaining obstacles to full competition were identified. To a large extent, these are due to the fact that transmission bottlenecks between countries occasionally create isolated price areas within which competition may be more limited from time to time than on the market as a whole. In Vattenfall's view, the best way to correct this problem is to increase integration of the Nordic Transmission System Operators (TSOs) and, above all, to invest in the removal of bottlenecks, financed from the transmission tariff, when and where this is economically justifiable. A more extensive discussion on bottlenecks, market subdivision, counter-trading and limitation on exports and imports was presented in the 2002 Electricity Market Report (page 26 ff).

The Nordic power markets currently all have their own TSOs; Statnett in Norway, Fingrid in Finland, Eltra and Elkraft in Denmark and Svenska Kraftnät in Sweden. These operate the national high voltage networks. Due to the high level of market integration, there is a significant amount of common interest in how the grids are operated and a great deal of interaction between the system operators to rectify any emerging problems.

From a wholesale market perspective, the winter of 2002/3 showed that the market is capable of handling swings in demand and supply satisfactorily – no outages occurred and rationing was not required. In spite of extreme drought and very low water levels in the Nordic reservoirs, the power generators and the power market managed to allocate available resources efficiently. Electricity prices rose, leading to a dampening effect on consumption, and also to power plant with higher marginal cost being taken into operation. These effects are all in line with what would be expected from an efficient energy market. The net result was that the threatened energy imbalance was managed satisfactorily.

From the customer perspective – and this applies to small and large customers alike - the situation may have been perceived differently. Occasionally, high spot price levels were significant enough to filter through to raised end-user prices, raising concerns about the effects of liberalization and market integration. But if the power market is to function properly, prices must be allowed to fall and rise in order to achieve balance between supply and demand – both in the short term

Figure 4: Nordic wholesale electricity prices 1996–2006.



Source: Nord Pool, 1 October 2003. Exchange rate used: EUR/SEK – monthly and yearly averages from REUTERS and the Swedish Bank.

and in the long term. And customers may need to become more aware of the fact that they are not at the mercy of energy prices – there are options that allow them to fix their energy price by choosing the right type of contract.

Service levels to small customers need to be improved

Vattenfall believes that for the market to work satisfactorily for all parties, it is essential that customers are content not only with the product they are paying for, but also with the service they receive in communication with both their energy supplier and their network provider. This applies both to small and to large customers. In the long term, no energy supplier will be able to keep and increase his market shares, unless he is able to keep his customers satisfied, regardless of whether they are current energy customers or network customers.

Many consumers perceive electricity bills to be complicated. Not only do they relate to the consumption of an invisible product stated in what to many are unfamiliar terms, but payment is often required in advance, based on estimated rather than actual consumption, and subsequently rectified as actual data becomes available.

In Sweden, for example, discrepancies between instantaneous, estimated and metered consumption obscure the consumer's perception of how much money he is due and when. This is not acceptable.

Vattenfall is aware of this problem, and is working actively to overcome it. Initiatives have been taken in the Swedish and Finnish markets, but our intention is to spread them to other markets as well, as and where we find that customers perceive it as desirable.

Vattenfall is also working to increase customer satisfaction, for example by installing meters that allow for frequent and regular remote readings of actual consumption. These meters will enable Vattenfall to issue invoices based on actual rather than scheduled consumption. As a result, Vattenfall will be able to discontinue advance payments. Customers are now able to read their own meters and communicate the data to Vattenfall for subsequent invoicing, thus having a double check on how much they have consumed and how much they are being asked to pay for. And finally, Vattenfall is introducing flat-rate monthly electricity charges for very small consumers with regular consumption patterns, where the customer pays a fixed monthly fee for both energy and network service, regardless of actual consumption.

Liberalization and restructuring of EU energy markets will continue

Deregulation, integration, consolidation and restructuring are set to continue

There are currently still wide differences between Member States in terms of how far they have deregulated their energy markets. The Nordic countries, the United Kingdom and Germany are at the forefront of this process, and are already fully deregulated in relation to the requirements of the Electricity Directive.

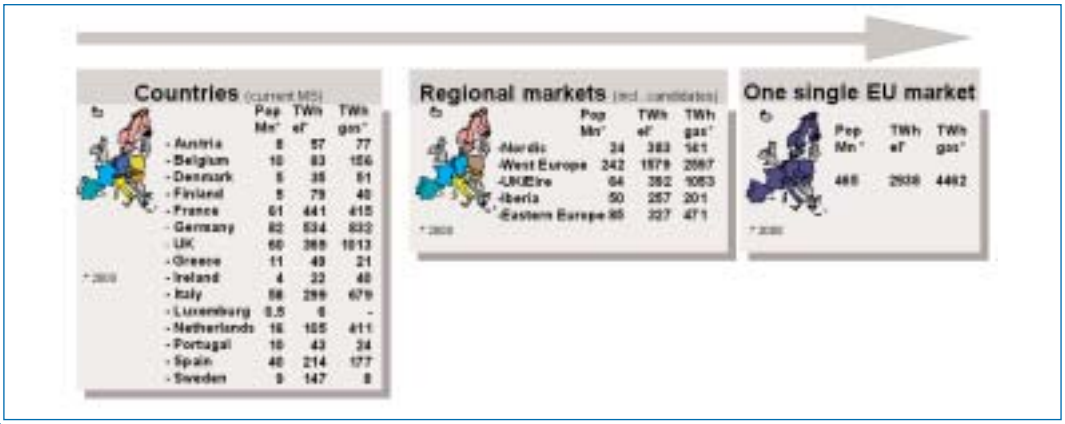
The objective of deregulation is to create better competitive conditions in total through efficiency gains in generation, transmission and market price formation. Pricing will be more efficient from an economic point of view, since it will reflect the actual intersection of supply of and demand for electric power. As a result, it is expected that prices will drop, costs will be lowered, service levels will be improved and that the total competitiveness of the Union in relation to other markets will ultimately increase. Deregulation at European level has so far taken place gradually and in many aspects been allowed to be managed by the preferences of individual Member States. This has led to certain Member States electing to follow a slower pace that has delayed penetration.

However, what we have seen so far is not the end of the game but the beginning. The Commission and other EU bodies will continue to have the initiative in forming the rules. One example is that the Commission will chair a Committee consisting of participants from the Member States that will decide on the further development of cross-border exchanges. The Commission will also produce a report on the implementation of the directive, including suggestions on how to improve the functioning of the market. The rationale behind the EU institutions' increased role in forming the electricity market is that it is a part of the total internal European market that in this case is one of the main vehicles for the development of the EU.

The Commission will continue to develop the internal energy market, and the focus is on increased cross-border exchanges, reliability of supply and avoidance of market concentration. Part of this development will be new guidelines, based on recommendations from the Committee mentioned above. The Commission's cooperation with the regulatory bodies in the various EU countries will also be reinforced. All this will result in increased efforts to create a more harmonized regulatory framework in the internal EU energy market. Still, the Member States will have strong opinions on the focus of this harmonization and the practical outcome is therefore difficult to predict, even though the trend is very obvious.

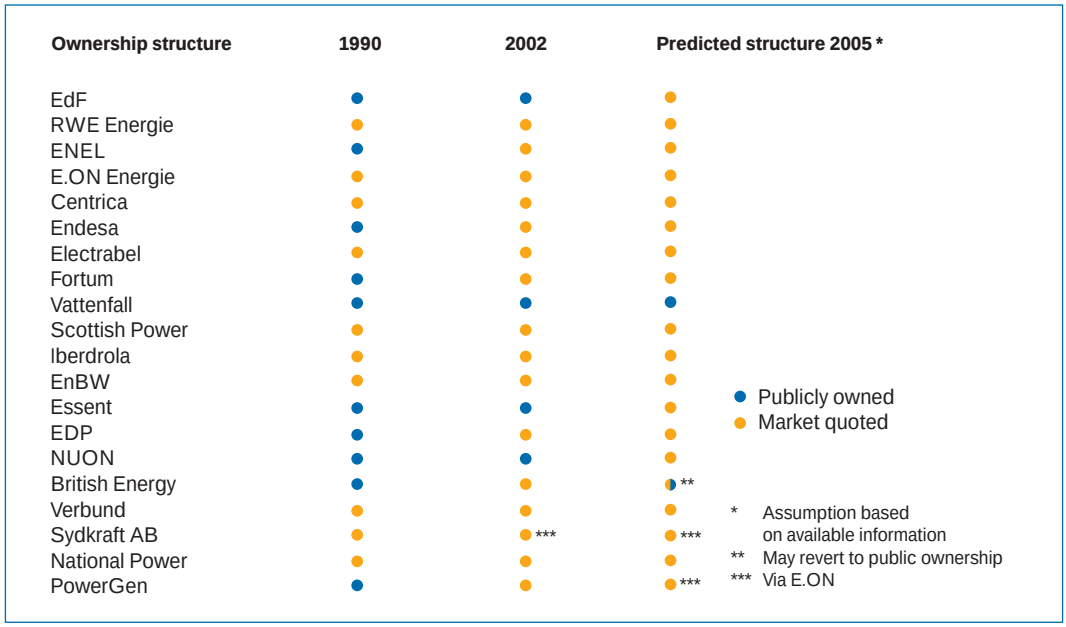
The ambition to create a common internal energy market will be achieved gradually over a period of at least 10 years. In a first stage,

Figure 5: Integration of the European electricity market .



Source: Vattenfall.

Figure 6: Accomplished and expected changes in ownership structure. Companies listed according to their size in 2002.



Source: Vattenfall.

regional markets covering several countries are in the process of being established.

As a result of deregulation and the need to break up national monopolies and other dominant players, many countries have chosen to privatize companies that were previously wholly or partly state-owned. Examples of this are ENEL of Italy, Endesa of Spain and Fortum of Finland. According to currently known plans, Vattenfall may, in 2005, be the only major European energy company that is still wholly state-owned.

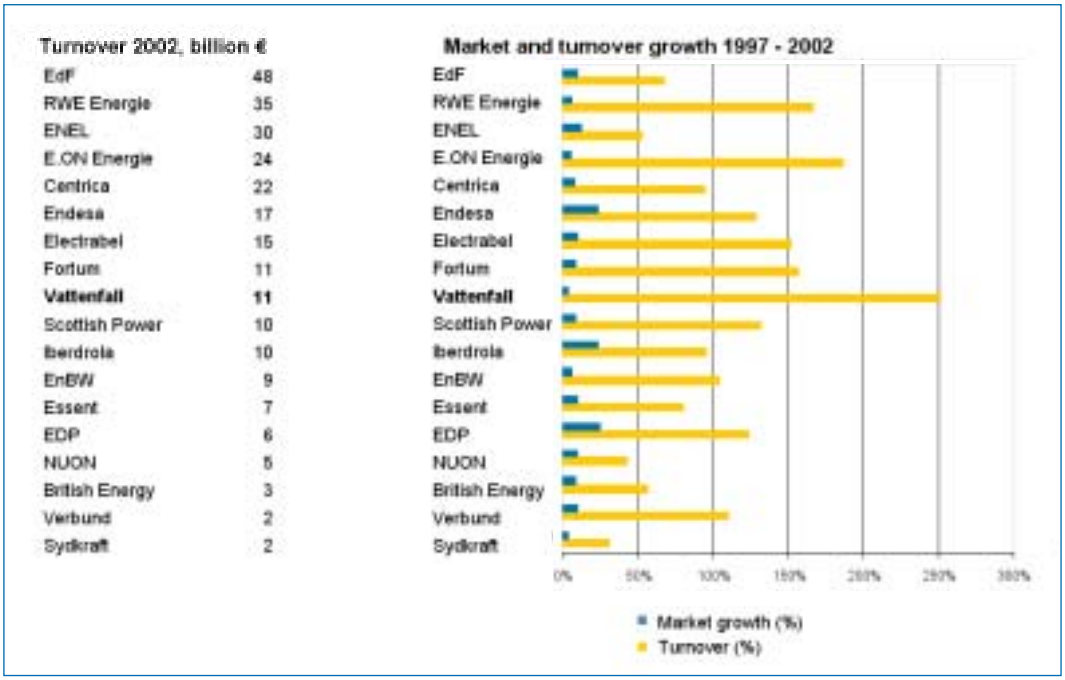
The effects of deregulation on market structures have been clearly visible in the past few years. Prior to deregulation, most national energy markets were isolated from each other in all significant respects, except for occasional power exchanges. National energy systems had been designed for self-sufficiency and maximum reliability of supply. As a consequence, economies of scale and opportunities for efficiency improvement on an international level were not put to use. As trade barriers between countries are dismantled and supply monopolies are broken up, a fragmented international market suddenly emerges, with many relatively small players when viewed from a European level. Many companies, including Vattenfall, have chosen to grow through mergers and acquisitions in order to achieve a size that is more compatible with the new, larger energy market.

This trend is obvious when comparing how the 18 largest European energy companies have grown in turnover terms between 1997 and 2002 in relation to market growth.

Consolidation has taken place not only within national markets but also across borders. Companies that have been prevented from growing locally because of their domestic market share and size have instead acquired foreign companies and thus developed into international players. Others have chosen to expand into new product areas, such as natural gas, water and telecom, thus creating new business models.

It was initially expected that a massive trend would begin of large companies absorbing smaller ones. This has not happened, at least not yet. Fragmentation has instead increased in some parts, at least temporarily. Some of the larger companies have been growing aggressively, while medium-sized players have been acquired. Others have found new business models, such as that of the multi-utility.

Figure 7: Turnover growth in relation to market growth, of selected European energy companies.



Source: Vattenfall.

A clear distinction between large, international players and small focused players is emerging. This consolidation process will continue until a sustainable balance is achieved. The driving force is higher efficiency through cost reductions, which will result in lower energy prices. A fragmented structure at European level is not efficient and does not, per se, lead to a healthy level of competition.

Consolidation and restructuring are expected to continue at the same pace in the short to medium term. E.On/Sydkraft's bid for Sweden's Graninge Energi may be one of the latest, but certainly not the last, example to prove this point.

This development is not unique; and other industries have experienced it as well. Studies of consolidating industries reveal a clear pattern. At first, there is some kind of fundamental change that drastically re-models the competitive landscape. It may be a shift in technology or a change in market regulation. Initially, fragmentation may increase as a result, as new entrants enter the market and try to compete with incumbents. A period of repositioning then ensues, as incumbents try to regain market shares by acquiring smaller units. Growth continues as larger and larger market players shift their attention towards increasing specialization on products or markets in which they have a significant and unassailable competitive edge. This is followed by a maturity phase, in which the industry gradually finds a sustainable structure, where all players can survive until a new shift occurs.

In the power industry, deregulation and market integration have resulted in a period of restructuring induced by fundamentally changed competitive conditions. Individual companies are driven by the insight that there is a correlation between degree of consolidation, size and profitability.

Management of and access to cross-border transmission links will become increasingly important

European electricity systems were designed to meet national needs for energy and reliability of supply. Cautious after the experiences of two world wars, followed by a pro-

longed period of cold war, most countries sought a high degree of self-sufficiency. As a result, power plant portfolios were made capable of meeting national requirements in all seasons of the year and at all times of the day, and transmission systems were made capable of transmitting power efficiently within the country. Links with other countries were put in place and routines for power exchange were gradually built up, but only for handling short and medium-term supply needs.

On liberalization, these national objectives were replaced by a desire to optimize the system at a higher level, in the interests of increased productivity and cost efficiency. Because of the wide scope for system optimization and resulting economies of scale, this makes sense in an integrated market area such as that of the EU, especially given the increasing need for using resources more efficiently in order to safeguard the global environment.

But in order to achieve efficient flows between national markets, cross-border links between countries need to be upgraded from purely national needs to higher capacity levels that reflect overall system needs, if the economic benefit of doing so for the whole system is higher than the cost incurred. Otherwise, the net effect would occasionally be similar to that which sometimes arises in the Nordic area, i.e. that energy price differentials arise between markets. When these are continuous and significant, they may reflect a lack of transmission capacity, rather than the electricity supply and demand situation. This is sub-optimal from the system point of view.

While the market requires these links to be upgraded, it may not be in the natural monopoly TSO's economic interests to build them. When shortages arise, many tariff systems are designed so that capacity is allocated to the user that is willing to pay the highest price. In some circumstances, it is possible for the TSO to make a profit from the existence of the bottleneck. Furthermore, in some areas, the allocation mechanism for the cross-border capacity, i.e. the auction principle, does not create an effective cross-border energy flow, since the demand and supply curves in the surrounding markets are not taken into account when deciding on the direction of flow. A market-splitting model for handling cross-border capacity would be more effective in stabilizing price differences between markets than the application of the auction principle.

If the overall transmission tariff is high enough to create incentives for new investments, and the TSO can be certain of capturing a large enough transmission volume to recover the investment costs, there may not be a problem. In a closed system in which fixed investment and operating costs can be passed on to users, cost recovery is relatively straightforward. But cross-border links introduce difficulties – they naturally fall within the remit of more than one TSO, thus creating the need for agreements on joint financing and cost, risk and revenue sharing. In addition, they redirect power flows over many systems and increase the uncertainty of being able to recover the fixed costs.

As long as there are insufficient incentives for the TSOs to increase cross-border capacity, this may not readily happen. Other measures will be required. As the Nordic competition authorities point out in their recent "A Powerful Competition Policy" report: "Transmission system operators should pay due attention to competition considerations in investment analyses of new transmission capacity". It is worth pointing out that investments in cross-border links could be made by any TSO (regardless of whether or not in a neighbouring market), and be either privately or publicly funded.

From the power generators' and power consumers' perspective, it is also important that the handling of energy flows is carried out on technically, economically and commercially acceptable terms. Transmission tariffs need to permit energy flows that do not discriminate between system users. They also need to be capable of providing incentives for investment, for example by evening out energy flows between areas of high consumption and low supply and those with low consumption and high supply. In some instances, it may be preferable from an economic point of view

to increase generation capacity locally rather than building more transmission capacity. In others, the opposite will be the case. But as long as there is no market mechanism or authority in place to make this decision, there is a risk that TSOs will act as natural monopolists and take the view that it is better to increase generation capacity, since the marginal effect for them of additional investments will more often than not be to increase average transmission cost. The result is economically inefficient decision-making and resource allocation.

As part of its TEN programme, the European Union has identified a number of cross-border links that need to be reinforced or built. EU funding is available to provide increased incentives. But receiving planning permission to build new links is very difficult and time-consuming in many countries. It may be worth reviewing whether this system needs revising in order to speed up the process.

In Vattenfall's view, any investments in increased transmission capacity need to be recovered through overall system-wide transmission tariffs and redirection of revenues between TSOs, not from end-users at the location or vicinity of the link, since these investments benefit all system users. This in itself is part of a larger argument in favour of regulated entry/exit or point tariffs, rather than negotiated, route-dependent or distance-related tariffs.

An example of continuous market adaptation of old contracts

In 1995, Vattenfall and the Polish electricity company Polskie Sieci Elektroenergetyczne SA (PSE) concluded an agreement for running a cable between Poland and Sweden, and for the supply of power from Sweden to Poland. The cable was to be a 600 MW high voltage direct current cable across the Baltic. The agreement with PSE included an undertaking that Vattenfall would accept responsibility for financing and running the cable in return for a Power Purchase Agreement (PPA) with PSE for energy deliveries to Poland on the level of 2 TWh per year at a fixed price. At the same time as the project was initiated, a new Swedish law was introduced that gave Svenska Kraftnät the sole right to build transmission links to foreign countries. The SwePol Link AB company was thus formed, with Svenska Kraftnät as part owner (51 %), Vattenfall AB with a 48 % holding and PSE with 1 %.

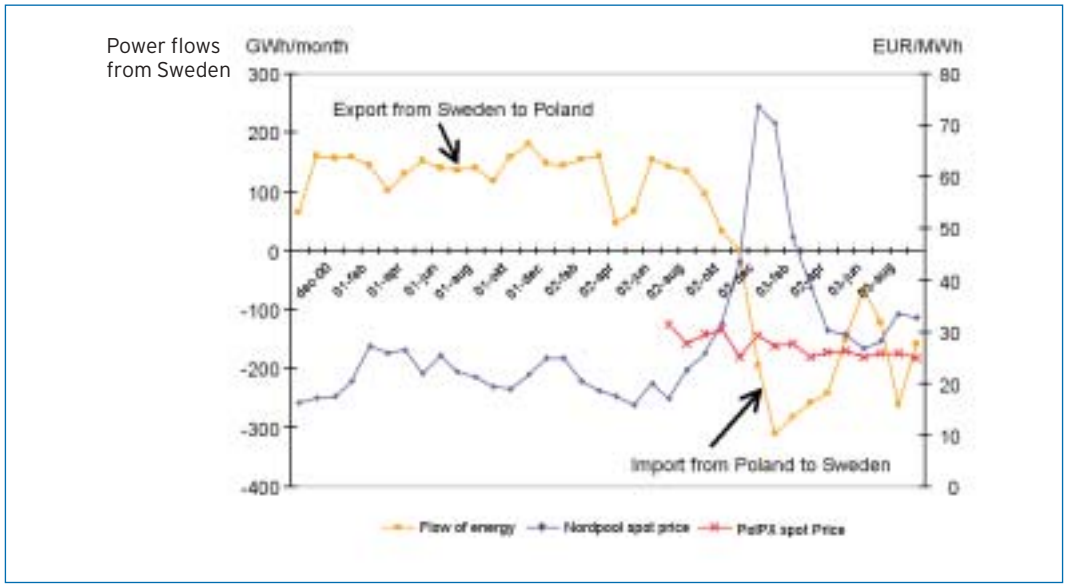
Vattenfall has a long-term right of use agreement with SwePol Link AB. Polish law was later also changed, and SwePol Link AB had to establish a Polish entity, the SwePol Link Poland Sp.z o.o. in order to obtain a licence and be able to sell transmission services in Poland. SwePol Link Poland Sp.z o.o. is wholly owned by SwePol Link AB.

There were several reasons for building the SwePol Link. The main purpose was to deliver power to Poland in order to meet the expected increase in demand in northern Poland, to strengthen the weak grid in northern Poland, and to provide a means for regulating the Polish power system. An additional purpose was to enable Sweden to buy electricity from Poland during dry years.

The agreement became unfavourable to PSE due to lower domestic energy demand and lower than expected power prices in Poland. In other words, the contract was based on the assumption that most of the time power would be delivered from Sweden to Poland, even though market conditions might suggest energy flow in the opposite direction.

The new contract concluded between Vattenfall and PSE includes a trading arrangement that gives both parties an incentive to optimize utilization of the cable by allowing power to flow in the direction for best market conditions. There is now a clear link in the contractual arrangement between market prices and the flow of power. As can be seen from Figure 8, the flow of power is now strongly correlated with electricity prices in the Nordic market. When prices are high, electricity is imported from Poland to Sweden, and when electricity prices are low, power is exported to Poland. Once the Polish power market is liquid enough to reflect short-term marginal cost rather than regulated prices, Polish power prices will also begin to influence the flow. It should be noted that the cable was temporarily out of operation in the autumn of 2002.

Figure 8: Current utilization of SwePol Link – direction and volumes.



Source: Vattenfall.

Price levelling between countries will continue

Electricity can now be traded both physically and financially across national borders, although not all countries have yet deregulated their markets to such an extent that competition can be said to work satisfactorily. As an example, it is still difficult to transmit electricity at reasonable cost to certain countries, unless the country transmitting electricity is the owner of the network. However, this is expected to change with growing pressure from the market. But it may take much longer to achieve a fully integrated and competitive market in Europe than it did in the Nordic countries.

On an increasingly competitive market on which the players have unrestricted access to transmission capacity within and between countries, electricity will always be bought where the cost is lowest. The result of this is that the generation capacity is put to use in order of increasing marginal cost, i.e. the most expensive source of power is the last one to be taken into operation. This last source of power utilized thus determines the spot price. In Northern Europe , for about 75 % of the time over the year, this source of power currently consists of coal fired capacity in Denmark, Finland and Germany. At other times, demand may be higher, in which case higher cost reserves need to be taken into operation. A further effect of market integration is that prices in the various countries will be correlated and gradually levelled out. This means that, in the longer term, a collective price pattern will be developed that clarifies how prices on different markets are interrelated and explains the difference in terms of variations in the transmission or transaction costs. At present, there is still considerable variation in consumer prices between different Member States, even when taxes and levies have been deducted.

The natural gas market in Europe will also be increasingly interlinked with the pricing on the electricity market. This is because natural gas can be converted into electricity. If the price of gas should fall, more electricity will be generated by gas firing, which will lead to a drop in the price of electricity. If the price of electricity should rise, it will be attractive to generate electricity by means of gas, and the demand for gas will increase, which will strengthen gas prices.

Network regulation should support a liberalized electricity market

Network operators in a deregulated electricity market

The transmission of electricity from the generation plant to the consumer is carried out by the transmission and distribution networks. There are three levels of transmission – the high voltage transmission grid that carries electricity over long distances and to neighbouring countries, the regional networks and the local networks. The local network transforms the electricity to household voltage levels and distributes it to consumers.

The transmission system is operated by a TSO (Transmission System Operator). Typically, there is at least one TSO in each country, but there may also be several (e.g. in Germany or Denmark). Local distribution networks are operated by network companies (sometimes called distribution companies). Since all grid operations are classified as natural monopolies, they have an exclusive concession to supply the customers in their distribution area.

Electricity consumers pay a total price for energy, which includes the price of electrical energy, and also taxes and the cost of transmission, which is known as the network tariff. This tariff consists of a transmission charge and a local distribution charge rolled into one. The first two components are relatively similar for all customers, but the local distribution charge may vary considerably. There are several reasons for this. For example, networks in densely populated areas will have lower per unit costs than networks in sparsely populated areas, or areas with difficult terrain (e.g. mountainous terrain). Networks built in the vicinity of industrial plants may have been designed to withstand extraordinary system stress to safeguard against disruptions that might adversely affect plant operations. New networks, or recently refurbished networks, may carry a higher cost than old ones. Because of all these factors, the costs of network operators vary. It is fair to say that consumers have little influence on network design, and should thus not have to pay for extraordinary investments caused by the needs of local industry, for example. But networks were generally designed prior to deregulation, at a time when such concerns did not exist.

Network operators also perform another task that is closely linked with that of electricity suppliers. Networks typically own the electricity meters of users, and carry out metering at consumer sites. Depending on the size of the customer, these meters can be either remotely read, or manually read on site at regular intervals (e.g. once a quarter or once a year). Some remotely read meters can even be read hourly, if required. However, metering is costly and the more frequently meters are read, the higher the cost. Networks have the responsibility to report measurements accurately and on time to suppliers. Without them, suppliers would have no information on the consumption for which to charge consumers.

Network tariffs, i.e. the charge consumers pay for these services, are set by network operators subject to regulatory supervision, or directly by the regulator. Regulatory principles vary between countries and several different philosophies and methodologies exist. Common to them all is that the regulation must satisfy several aims.

- To provide non-discriminatory network access to all users (sellers and buyers).
- To reimburse network operators for reasonable costs.
- To provide network operators with reasonable return on capital (profit) that gives them the incentive to invest in extensions or refurbishments.
- To provide network operators with incentives to increase efficiency, ensure acceptable levels of reliability of supply, and produce timely, accurate and understandable electricity bills.
- To shield consumers from monopoly abuse.
- To be workable, practical and easy to understand, so as not to cause an excessive workload for the regulatory authorities, which would cause unnecessary administrative costs.

As we shall see, these aims are not easily

combined into a single all-encompassing regulatory philosophy.

Regulation of network operators – Vattenfall's view

Vattenfall has network operations in several countries that apply different regulatory models. As an experienced operator in liberalized energy markets, and firm believer in the advantages of competition, Vattenfall has formed its own view of how the natural monopolies of transmission and distribution should ideally be regulated in order to support a well-functioning energy market.

Distribution networks that sell services related to the transmission of electricity are dissimilar to the market for electricity supply, in that they are natural monopolies. Since it would be economically inefficient to have parallel electricity networks, competition in network services has been ruled out. Customers thus have to buy network services from their local distribution company.

The method of network regulation is an important issue, since it ultimately affects customer confidence, the availability of market access, the inclination of operators to invest in the upkeep and expansion of the system and thus the reliability of supply. Customers want safe and reliable power deliveries from the supplier of their choice, and it is the task of the networks to make available the necessary capacity. There are no competition-induced incentives for networks to increase their efficiency, productivity or cost-effectiveness. These incentives have to be provided by regulation.

Several models that are suitable in different circumstances exist for this purpose. The first choice to be made is whether to regulate costs or performance. Purely cost-based approaches have the disadvantage of removing the incentive for performance improvements. A system that provides inherent incentives for improvement on the basis of providing opportunities for profit enhancement would appear to be preferable.

Instead of focusing on actual costs, the regulator can opt for considering performance, or what costs ideally ought to be. Yardstick competition is an example of a workable approach. Network companies are divided into groups with similar characteristics. Tariffs are then compared, reviewed in relation the specific circumstances of the relevant operating company, and those that stand out must be explained. If there is no justifiable cause for the higher tariff, the tariff can be lowered.

Regardless of which regulatory approach is chosen, a related issue concerns the regulator's need to define what constitutes a reasonable rate of return on capital. Without a reasonable rate of return, network operators will have no incentive to invest in new capacity, or to upgrade existing assets. The permissible rate of return needs to reflect both the cost of capital and the risk of the investment.

Secondly, tariff regulation can be ex-ante or ex-post. Ex-ante means that the regulator reviews and approves tariffs prior to allowing their application, while ex-post means that the regulator will intervene only if the tariffs applied are perceived as unjustified. The latter is viewed as a less invasive approach to regulation, since it is based on the presumption that most network companies wish to behave in accordance with market and regulatory requirements. However, in either system, the regulator is required to form an opinion of what constitutes a justifiable tariff, which will vary widely between networks and is thus not easy to determine or assess.

Each country must develop its own regulatory model that is suited to its history and current system, but the objectives should be the same. The presence of credible and independent regulators is beneficial, as these increase regulatory safety, and the practice and application of rules becomes more stable and predictable. Moreover, there must be a real chance of appeal against the regulator's decisions, and the appeal process should not be too time-consuming or costly.

In Vattenfall's view, the development of the market should be left to the market participants to the greatest extent possible, and the regulator's activities should ideally be supervisory and comparative rather than prescrip-

tive. The reason for this is primarily that, when there already is a working system in place, the most pragmatic and efficient way to change it is from the bottom up, gradually removing imperfections. The opposite approach, to superimpose a theoretically contrived system on an existing one, is bound to create more problems than it solves before it starts working satisfactorily.

Ex-post regulation in which the regulator approves tariffs after implementation and corrects them if found unfair is a preferred regulatory model, since it leaves the pricing responsibility with the distributors. In assessing the fairness of tariffs, a regulatory model that is incentive-based and considers the output of network operations in relation to best practice costs is desirable. In order to provide reasonable guidelines for the distributors, it is important for the regulators to establish a view on what is an acceptable long-term level of return on investments in network operations.

Due to fundamental driving forces, electricity costs may rise in the long term

Vattenfall expects electricity prices to rise in relation to normal year average levels due to several factors

As electricity demand continues to grow, and existing capacity must be shut down at some point due to obsolescence, power markets eventually reach a stage when new capacity is needed. This process may be longer or shorter, depending on local conditions, conservation efforts and political decisions. In the Nordic area, new generation capacity is expected to be needed after 2013 to compensate for scheduled plant shut-downs and to meet the growing electricity demand. In Germany, generation capacity will have to be replaced between 2010 and 2020 as a result of the decommissioning of nuclear power and the growing need for refurbishment of old plant. The Polish market will remain oversupplied at least up to 2010, so no investments in new capacity are expected in the short term.

The consumption of electricity in the Nordic countries is expected to continue to increase slowly at the rate of around 0.6 % annually and somewhat more rapidly in Finland (1 % annually). Consumption growth in Germany is also expected to be low at around 0.5 % annually. Low population growth, efficiency improvements in electricity utilization and reduced electric heating are the reasons behind these expectations. Poland expects slightly higher growth rates, especially in industry, as economic development accelerates as a result of EU accession.

Many older generation plants will gradually have to be upgraded until the costs of doing so are too high in relation to prices. They will then be shut down.

During the ten-year period after 2013, most of the remaining 10 or 11 nuclear power units in Sweden (depending on the impending decision concerning Barsebäck 2) and all of the four units in Finland will have reached an operating life of 40 years, which was assumed in the Swedish Decommissioning Act to be the probable economic useful life of this type of plant. In the opinion of Vattenfall, it is generally possible to extend the useful life further by reinvestments. However, one or more of the oldest and smallest units may be shut down for economic reasons before 2020. The effect of this may be a reduction in capacity of between 4 and 22 TWh. At the same time, it must be emphasized that taxes and other regulatory measures are of decisive importance. Operation of the remaining nuclear power units is assumed to continue. In addition, between 14 and 16 TWh of old coal-fired condensing power plants in Denmark and Finland will be shut down during the period. The Finnish Parliament has recently decided to permit the construction of a fifth nuclear power plant that could add another 10 TWh annually, and could come on stream in 2009/10. In Germany, 40000 MW of generation capacity will need replacing between 2010 and 2020.

What will replace this capacity
and how will it be done?

Investments in new capacity will take place only if economically profitable

As the electricity market approaches its capacity ceiling, electricity prices will gradually rise to a level where long-term prices correspond to the full cost of new capacity. The rate at which generation capacity is expanded will be determined by market prices.

By how much must the price rise to provide the incentive for new plant construction?

In a recent study, Vattenfall has compared generic generation costs by selected types of plant, regardless of plant siting. Several commercially realistic alternatives are available. The results are summarized in table 1.

The long-term marginal cost based on a natural gas fired, combined cycle plant is around 2.9–3.6 €cent/kWh (29–36 €/MWh) or higher. Long term electricity prices will have to rise above these levels for new plant to be built. From this perspective, rising electricity prices seem inevitable in the long run.

The electricity market will provide sufficient incentives for the electricity generators to build new generation capacity whenever this is needed, provided that the regulatory mechanisms and the permission-granting processes are adapted to the needs of the competitive international electricity market. The electricity market and electricity prices also give customers incentives for savings and efficiency improvements. The type of generating power that is added will depend on how the regulatory mechanisms and permission-granting processes are set up. Environmental control mechanisms and fiscal instruments will have a central role to play in this respect.

Several different types of power generation technology are available as options for new power plants. For example, a new coal-fired plant is presently cost-competitive due to relative fuel prices, but still presents an environmental problem as the CO_2-emissions issue has not been solved. A gas-fired plant has less CO_2-emissions than a coal-fired plant but is presently not cost-competitive. A biofuelled plant is very costly to run and has to

Nuclear Decomissioning in Sweden

- Sweden today has 11 operating nuclear reactors. The ambition is to phase-out nuclear energy when it can be substituted with sustainable alternatives.
- In 1997, Parliament decided to decommission both reactors of the Barsebäck nuclear power plant, provided that the resulting deficit is covered by new production and a more efficient use of electricity.
- Barsebäck 1 was closed in the end of 1999. Most of the power generation from Barsebäck 1 has been compensated for by means of imports.
- Barsebäck 2 (B2) was initially planned for closure by the 1 July 2001. Since the conditions for decommissioning have not yet been fulfilled, the decommissioning has been postponed.
- B2 has now been included in the negotiation between the State and the industry on the long-term energy adjustment strategy that includes decommissioning of the remaining 10 reactors in Sweden, giving priority to a rapid decommissioning of B2.
- If no agreement is reached on B2 by April 2004, the Swedish government has the ambition to use the decommissioning law from 1997 to decide on the shut down of the reactor.

Nuclear Decomissioning in Germany

- Germany today has 19 operating nuclear units and has decided to cease electricity production based on nuclear energy.
- The "Act on the Controlled Phase-out of Nuclear Energy Use for Commercial Electricity Generation", enforced on 27 May 2002, fundamentally amended the Atomic Energy Act that dated back to the year 1959. The purpose of this law has changed from the promotion of nuclear energy to the controlled phase-out of its use.
- The "Energy consensus" achieved in 2001 between the operators of the German nuclear power plants and the German government has lead, by mutual agreement, to a change in the Atomic Energy Act.
- The Act specifies remaining amounts of electricity approved for each power plant, and allows operators to continue to run their power plants in an organised manner until decommissioning.
- The first power plant, Stade, will be decommissioned in 2003.
- As the law stands, the remaining nuclear power plants will be phased out between 2009 and 2017.

Table 1: Generic electricity generation cost in selected new types of plant independent av geographical location which could add on to cost. Assumed CO_2 cost of €20/ton CO_2 from 2020.

Type of plant	*Total electricity generation cost €/MWh, net of emission rights trading cost*	*€cent/kWh*	*Total electricity generation cost €/MWh, including emission rights trading cost*	*€cent/kWh*
Gas fired combined cycle	29	2.9	36	3.6
Coal PF power only	26	2.6	40	4.0
Lignite PF power only	23	2.3	39	3.9
Coal CHP	19	1.9	29	2.9
Gas fired CHP	27	2.7	32	3.2
Bio fuel CHP	46	4.6	46	4.6
Wind power	52	5.2	52	5.2

Source: Vattenfall.

rely on economic support mechanisms to be profitable.

Which technology is chosen will depend on circumstances in the individual investment case. It will depend on how the investor views the long term economic prospects of the individual project, which is a function of fuel prices, environmental factors and other risk-related elements.

The planning and construction of new power plants takes a long time. Sites must be found and acquired, planning licences must be granted, environmental consequences must be considered and approved, projects must be planned and contracts negotiated. Since the market has not yet experienced the effects of a sustained lack of capacity, it cannot be expected to be familiar with its effects. This is an area in which the market still lacks maturity – the cycles are simply very long and the critical phase has not yet been reached. Therefore it is important to remove unmotivated barriers preventing new capacity coming on stream as a reaction to clear price signals.

There are several factors and circumstances that in combination may put upward pressure on market prices

Green certificates

Governments in many countries have long supported the development and demonstration of new, desirable and renewable energy technologies, sometimes also meeting the initial investment costs to facilitate market entry. This has been the case for biofuels and wind power in particular. The support has come in many forms, such as investment grants, guaranteed prices, additional allowances beyond market prices for the electricity generated, or tax relief. The support has been paid directly by the Government or by the electricity distribution company (by granting certain prices for deliveries of electricity), and thus ultimately by the end consumer.

For example, as of 1 May 2003, Sweden has introduced a system of green certificates (GCs) whereby the end consumer pays for the economic support of selected means of electricity generation. The Government issues the GC to the qualifying plant, primarily power generation from wind, biofuels and new hydro power, principally one GC per kWh. The end

Green certificates in Sweden – how does it work?

- Green certificates in Sweden are called electricity certificates and were introduced on the Swedish market on 1 May 2003.
- The purpose of the certificate is to promote the consumption of electricity produced from renewable energy sources (RES). The promotion of RES has earlier been financed by the state budget but will from now on be taken care of by the market and financed by the end consumers.
- Every customer is obliged to buy a certain amount of certificates in correlation to electricity consumption.
- Certificates are bought on behalf of consumers by electricity suppliers, who pass on the cost to their customers.
- The producer of electricity from RES (primarily wind power, bio fuels and new hydro power) sells the certificates, thus obtaining a revenue which supports his production.
- The current quota is 7.4 % but will gradually increase until it reaches 16.9 % in 2010. The objective is to increase the total production from RES in Sweden by 10 TWh by 2010.
- For consumers, this implies a cost of just above 3 € for a customer with an annual consumption of 2000 kWh/ year (e.g. an apartment) and around 33 € for a customer with an annual consumption of 20000 kWh/year (e.g. a detached one family house).

consumer is then obliged to purchase a certain quota of such GCs through his retail supplier in relation to his consumption. The current quota is 7.4 % and will gradually increase to 16.9 % so that, by 2010, the total volume of GCs in Sweden will be equivalent to 15–20 TWh. Some industrial customers are exempt.

This system enables the retailer to buy his power from any generator, irrespective of the generation mix, and buy the required volume of GCs separately in the market. The price for the GC has been increasing during 2003 and was approximately 28–30 €/MWh in September 2003, which provides significant additional revenue for the generators of such power.

As the total requirement for GCs gradually increases, the prices can be expected to rise further, thereby stimulating the building of more renewable power generation capacity. Concurrently, the consumer price of electricity will rise.

CO_2 emissions trading

On 2 July 2003, the European Parliament voted with overwhelming majority in favour of a Directive establishing an EU emissions trading scheme to become effective on 1 January 2005. The purpose of the scheme is to direct physical reductions of emissions of six greenhouse gases (GHGs), initially only CO_2, to where they are most cost effective. The scheme will include six industrial areas that account for 46 % of these emissions in the EU, the energy sector being the biggest emission source. This is one important element of the EU meeting its obligations under the Kyoto protocol to reduce greenhouse gas emissions.

The basic mechanism is that all plants above a certain size must be in possession at all times of emission allowances equal to their emissions of GHG. The allowances will be allocated by a government authority in each Member State, based on various considerations of historical emissions and technical standards. The allocation is very largely left for the EU Member States to decide in accordance with the general principles of the Directive in so-called National Allocation Plans that are to be approved by the EU Commission. The total number of allowances will then be gradually reduced to reflect the reduction targets set to meet the Kyoto protocol and subsequent agreements on the sharing of that reduction among EU members. During the first trading period, 2005–2007, a maximum of 5 % will be auctioned and the rest will be issued at no cost to the plant owners. The next trading period, 2008–2012, will maybe see an increase in the limit of 10 % that is set in the Directive. The allowances can be traded between plant

owners and others, and a market will develop. When allowances become scarce, they will have an increasing market value and the plant owner will have a trade-off between investing in physical reductions and trading allowances in the market. Physical reductions will thereby be directed to where they are most cost effective. The price of allowances will depend on the scarcity, i.e. the amount of physical reductions, and the cost for such reductions.

In a deregulated market, the wholesale electricity price is basically set by the marginal generation cost of the last running unit in the order of merit, i.e. the running power plant with the highest marginal generation cost. This marginal cost includes the value of the allowance. The last running unit is always a fossil-fired plant either in Germany, Poland or in the Nordic system, except at times of low demand and very good supply of hydro power. The allowance cost is thus always a part of the price setting marginal cost. Consequently, the wholesale market price of electricity will increase as the price of allowances increases.

Vattenfall estimates that an allowance cost of 5 €/tonne will add 2–3 €/MWh to the price of electricity and 10 €/tonne will add 4–6 €/MWh. Higher prices of allowances will obviously increase electricity prices further, but there will then probably be changes in demand growth as well as significant changes in power flows between countries and regions, and greater impact in relative cost differences between existing and new plants as well as between different sources of power.

The prices of allowances will depend on the requirements for physical reductions and the actual cost of such reductions. It is likely that a large number of small improvements will initially be made at low cost, but sooner or later more significant steps will have to be taken, including the construction of new plants and decommissioning of old, less efficient plants with high emission costs. In the longer term, electricity prices will reach levels that can support the total cost of investments in new, more efficient plants, including the costs of a smaller number of allowances at higher cost.

The Directive establishing a scheme for Emissions Trading – what does it mean?

The Kyoto Protocol
– commits the EU Member States to reducing their aggregate emissions of greenhouse gases (GHG) by 8 % by 2012 compared to 1990.

The EU scheme for Emissions Trading
– a tool to fulfil the EU Kyoto commitment in a cost effective manner.

Emissions Trading
– trading with emission allowances.

Emission
– release of greenhouse gases (GHG) into the atmosphere.

Greenhouse gases
– Carbon dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O), Hydroflourocarbons (HFCs), Perflourocarbons (PFCs) and Sulphur Hexaflouride (SF_6). Only CO_2 allowances will be traded initially.

Allowance
– allowance to emit one ton of CO_2 or an amount of any other GHG with the same global-warming potential.

Trading periods
– 2005–2007 and 2008–2012.

National allocation plans
– to be developed by each Member State, stating the total quantity of allowances and how to allocate them. The plans shall be notified to the Commission by March 31 2004 for its approval.

Allocation
– allowances shall basically be allocated free of charge. During the first period 5 % may be against payment, during the second period up to 10 %.

Start of scheme
– trading within the EU will start on 1 January 2005.

Liberalization has exposed risks that were previously hidden

In a liberalized, competitive market it is natural for prices to fluctuate

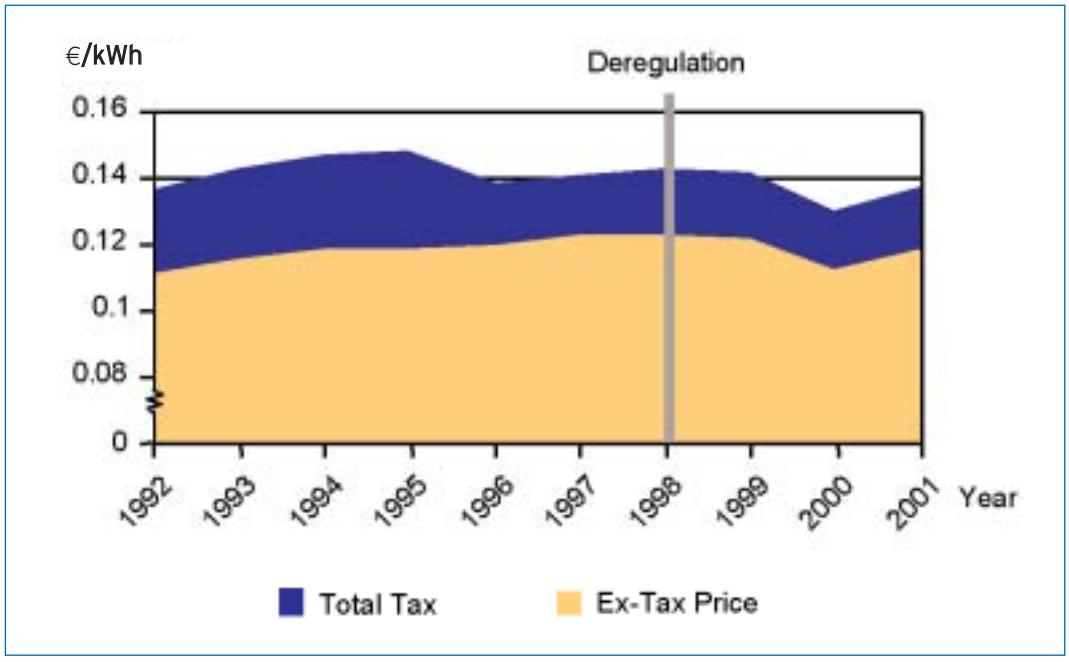
In Europe, as well as in other parts of the world, the electricity industry has played an important part in building up wealth, productivity and the standard of living during the past century. The pioneering companies that built up the electricity systems faced a monumental task. Huge risks and capital investments lay ahead of them. In order to provide incentives to go ahead with this undertaking, most governments created market systems that allowed for a speedy investment recovery. These systems survived until it became clear that the electricity system was largely completed, and no more major investment programmes remained.

In the old system, all costs could be passed on to consumers. Electricity tariffs were set annually, based on generation planning and expected demand. Cross-subsidizing between user categories was not uncommon – all in the interest of expanding market volume in order to achieve maximum cost recovery. Needless to say, prices did not fluctuate – they rose steadily over time, in pace with the inflation rate or slightly less.

So what was wrong with this world? Well, for one thing, consumers had little incentive to curb their use of energy during periods of high demand and low supply. In some countries, this has led to a wasteful attitude to the use of energy. Generators had an obligation to supply, so they had to design the system to meet even the most extreme demand peaks. In addition, the fact that they could pass all costs on to consumers means that they had no incentives to improve their cost-effectiveness.

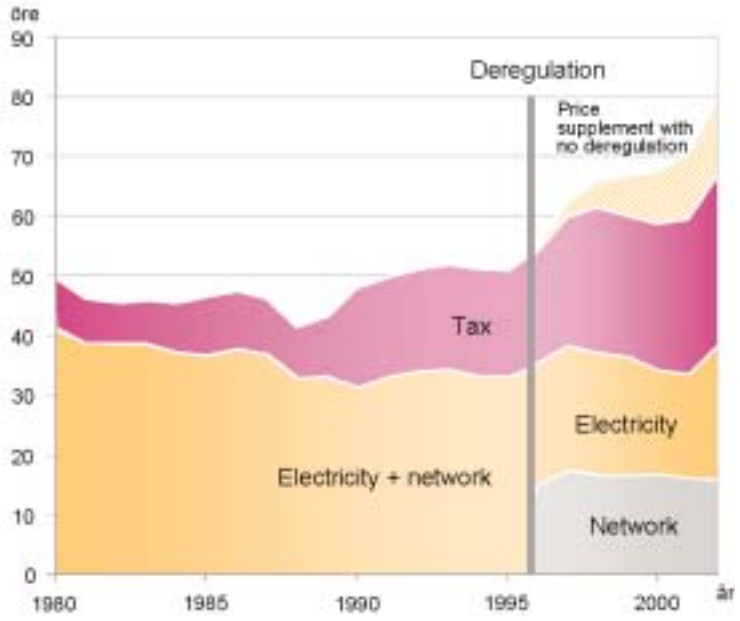
But where did the price fluctuations come from? The answer is that in a free and competitive commodity market without long term

Figure 9: Average electricity prices and taxes for households in Germany prior to and after deregulation, €/kWh.



Source: IEA Energy Prices and Taxes.

Figure 10: Average electricity prices and taxes for a house with electric heating in Sweden prior to and after deregulation (1990 monetary value, öre/kWh). Note that we have used Swedish öre per kWh instead of €/kWh since the euro did not exist before 2001. Readers who wish to convert the graph to euros could use an average exchange rate of SEK 9/€ as a reference.



Source: Swedenergy (Swedish electricity association) & Vattenfall.

capacity shortage, prices will be set where demand intersects with supply. The supply curve, in turn, reflects the short-term marginal cost, which is the price at which generators will bid electricity supply to the market. To make their capacity available, generators want, at the very least, to cover their short-term marginal (i.e. variable operating) cost. It is worth pointing out that a price at the short-term marginal cost would not cover the total cost of the capacity, but it does at least cover the cost of keeping the plant in operation.

The short-term marginal cost is very low for most hydro power plants, somewhat higher for nuclear plants, higher still for conventional thermal plants (coal or gas fired) and highest for reserve capacity such as, for example, gas turbines. This system ensures that plant is utilized in the order of increasing cost. The order in which plant is utilized is relatively fixed, and is called the **merit order**. However, if the relative fuel costs should change, for example, the merit order may also change.

The short-term marginal costs were obviously different for different plants in the old system too. The difference between now and then is that the costs were hidden. Prices were set to cover operating and capital costs of all plants. Low-cost capacity thus subsidized higher-cost capacity. There was no market mechanism in place to ensure that plants were actually utilized in the order of cost. This usually happened anyway because of generation planning, but factors other than cost were also able to determine the merit order.

In economic terms, the new system is preferable, since it has in-built efficiency incentives. The fact that the liberalized system is more efficient than the old one has been proven by the fall in electricity prices and in generation and distribution costs since liberalization.

In fact, Vattenfall calculations have shown that if the old system had still been in place, the average wholesale price level in Sweden would today be up to 40 % above the average energy price level (see dashed area in the figure above).

Another element that has been introduced with the competitive market is risk. In the past, power generators absorbed all risks. They carried the risk of rising fuel prices, the risk of supply not meeting demand or vice versa, the risk of plant failure, the risk of network failure, and so on. In return, they were shielded from competition and allowed to pass on the costs. Consumers, on the other hand, enjoyed a high level of collective insurance against the effects of power outages.

Now, generators no longer have guaranteed markets, and cannot pass on the costs to the consumers. To compensate for that, they have passed on some of the price risk to the consumers (via the electricity suppliers, since customers do not buy power directly from the generator). For those consumers who do not wish to accept risks, insurance is provided in the form of fixed price contracts. Risk and the cost of removing it have become visible. The collective insurance has been replaced by a minimum level of insurance provided by the TSO in the form of reserve capacity.

However, generators are still exposed to risk. For example, generators may wish to ensure a certain level of income for the volumes they sell on the spot market. Since prices vary, the income level is by no means given. To secure the revenue stream, generators will plan generation levels to such an extent that they are able to meet the demand. Ideally, this reduces fluctuations below levels at which generators are unprofitable. The price they pay for this is the forfeiting of income earlier in return for income later. They also have the possibility of hedging their generation, e.g. on the forward market. Hedging essentially means persuading someone else to carry the risk to which the generator is exposed, i.e. the risk that the price will fall between now and the time when the generator's output is scheduled to hit the market. For assuming that risk, the hedging opposite party will charge a fee.

Illustrating the effects of risk: The Nordic dry years of 2002 and 2003 – are high prices here to stay?

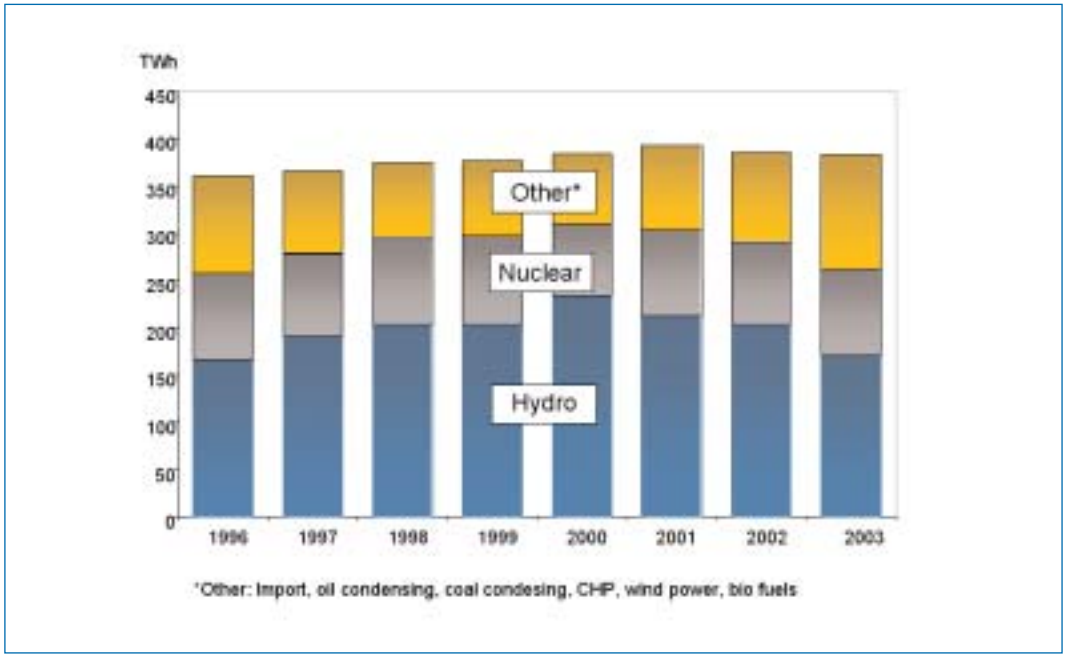
In the Nordic market, high and fluctuating electricity prices and supplier interaction have continued to be the customers' greatest concerns throughout 2003. Low reservoir levels have given rise to very high prices, also during the summer months. A multitude of different contracts are now available on the retail market, which allows customers to choose not only their suppliers, but also the level of desired price stability. Nonetheless, many household customers may find it hard to see the link between supply and demand and their resulting energy bills.

As explained above, consumers in the liberalized market have been made to assume some risk. In return, they received more cost-effective and transparent electricity supply. Even so, they are able to hedge the risk by buying fixed price contracts. Since this means pushing the risk back to the supplier, it is only natural that the supplier will demand a higher price for a fixed price contract than for a variable one.

So what is it that has happened during the dry years of 2002 and 2003? How is it that power generators allow these extreme situations of power shortage to arise and prevail? What role do weather fluctuations play? Are generators deliberately exploiting the situation to increase price levels more and for a longer period of time than might be justifiable from a market point of view? As explained below, generators manage their production based on predictions of demand and supply which, in the Nordic countries, is highly dependent of the weather and precipitation. Predictions are made on the basis of experience, and usually foresee normal conditions while allowing for slight variation. Extreme weather situations can thus catch a generator by surprise, just as it does anybody else.

The Nordic electricity system has a generation capacity of 410 TWh. In a normal year, hydro power contributes around 50 % of the power required to meet the demand. But in years with unusually high or low precipitation,

Figure 11: Variation in Annual Contribution of Hydropower to Nordic Electricity Supply.



Source: Vattenfall.

hydro power plant may produce much more or much less power than normal. As the price on the spot market is solely a function of supply and demand, the resulting price level will vary accordingly. In dry years, prices will be high, and in wet years, prices will be low.

Since the Nord Pool power market is an anonymous auction, market manipulation is virtually impossible. All generators bid to close the gap between their own generation and the forecast consumption. Generators with excess generation capacity have an incentive to ensure that this gap is closed, so they will bid to get rid of their lowest cost (short-term marginal cost) generation first. Naturally, they will wish to secure as high a price as possible for their power. There is thus a balance to be struck between the need to offset excess power and what the trader perceives is the highest price he can get away with. This is normal market behaviour, and is nothing sinister. Generators with excess consumption will behave in the opposite way – wanting to maximize the spread between the price they obtain from their customers and what they have to pay for the power in the market. The net effect of this behaviour is that, in situations of shortage, prices will rise until demand is satisfied, and in situations of excess supply, prices will fall until all offset possibilities have been exhausted.

A particular problem worth mentioning in this context is the relative inflexibility of the power demand. Since consumers have no direct relation with the market other than a contract price created from a market price average, there is no direct link between instantaneous price levels and consumption. In addition, the inclination of consumers to increase their consumption just because prices are low is limited – since electricity cannot be stored, it is useless to buy more than you need, and the added benefit of brightening the lights a touch more is usually very low. Equally, when prices are high, it may not be attractive for all consumers to turn down the heat or turn off their computers just to save a few pennies. However, there are applications in which this is both possible and attractive, such as some industrial applications, or for households, the ability to run the washing machine at night. In the interest of economic efficiency as well as resource conservation, it would thus seem desirable to improve the responsiveness of

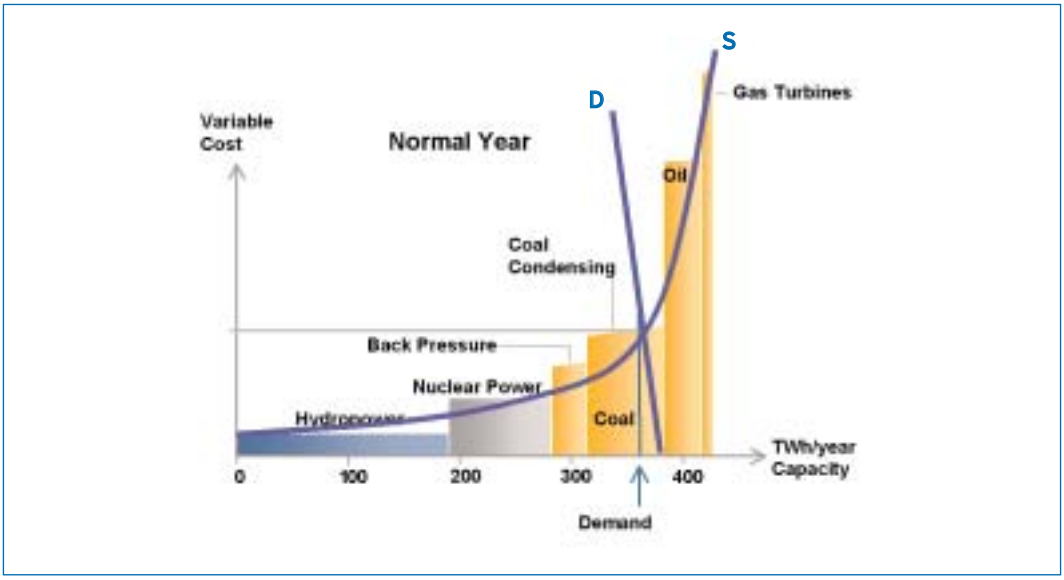
the market to high market price levels by creating more direct links between consumption and price.

Every year, daily and hourly supply and demand is affected by a large number of factors. In a typical annual cycle, water reservoir levels will be lowered over the course of the year in order to make room for the melting water of the spring flood. Water is then used conservatively over the year in order to save capacity for the higher consumption levels and prices in winter. There may be an additional inflow of water into the reservoirs in the summer and autumn, in which case it is sometimes necessary to spill water in order not to overfill the reservoirs. The power output of nuclear plants may also vary over the course of the year. Spent fuel must be replaced by new fuel every year, and during refuelling, the power generated will drop.

The total annual demand in the Nordic area is currently around 380 TWh per year. This means that, in a normal year, supply and demand curves will intersect in the band of thermal coal-fired plant. Spot prices of electricity will thus normally reflect the marginal cost of generation in coal-fired power plants, which at current coal prices is 20–25 €/MWh. Occasionally, at times of unusually high consumption or unusually low levels of supply, prices will be higher. They may also be lower when consumption is low and supply is abundant. The fact that the marginal cost of generation in plants lower down the merit order is lower than that of coal-fired plant, and that generators with only hydro power in their generation portfolio receive prices above cost for their power is immaterial to the spot price level.

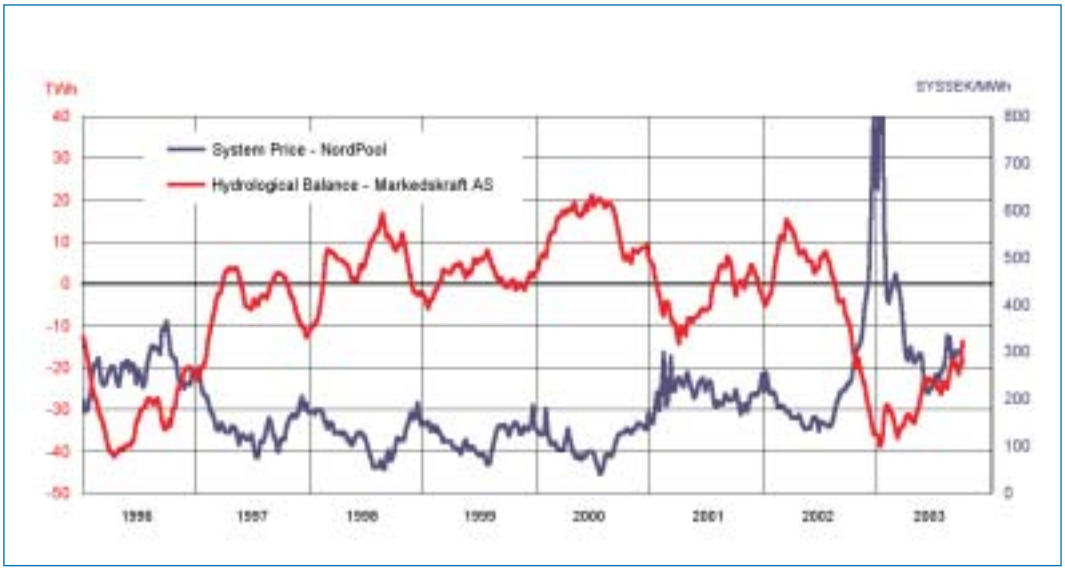
Spot prices on Nord Pool are closely correlated with the hydrological balance, i.e. the total volume of water stored in reservoirs at a given time in relation to the level normally in storage at that time. Because the marginal cost of hydro generation is very low and there is

Figure 12: Supply and demand in the Nordic region.



Source: Vattenfall.

Figure 13: Correlation between Nord Pool spot price and hydrological balance.



Source: Vattenfall & Nord Pool, 1 October 2003.

ample scope for storing water in reservoirs, every generator must optimize his generation. This means that reservoirs will be utilized to generate as much electricity as possible when prices are high (usually when consumption levels are high), and then in falling quantities at lower and lower prices until all water is used up. It is therefore important for a generator to conserve water in dry years and be careful not to spill water needlessly in wet years. Generation planning requires advanced simulation techniques to model probabilities of future reservoir levels. The usage of hydro power is also restricted (flows, levels) by special regulations. Generators may be powerless in the face of variations in the weather, but they have the means that enable them at least to predict what will happen to prices depending on the development of reservoir water levels.

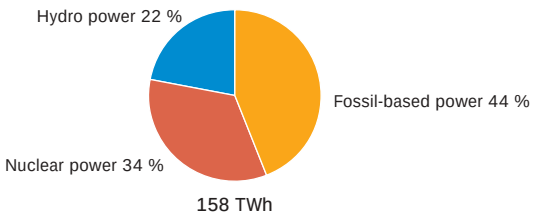
The chart above shows the development of Nord Pool spot prices since 1996, which was a very dry year. Spot prices soared. The following years were wet and normal, with falling demand. Prices fell both because of this and because of the effects of liberalization. There is no reason to believe that wet years will not recur. However, it should be remembered that the hydrological balance is one of the most important short-term factors affecting price in the Nordic market. Underlying long-term factors, such as the capacity balance, technical development, environmental measures and fuel prices also affect prices. And in the long term, these will determine the cost of electric energy.

About Vattenfall

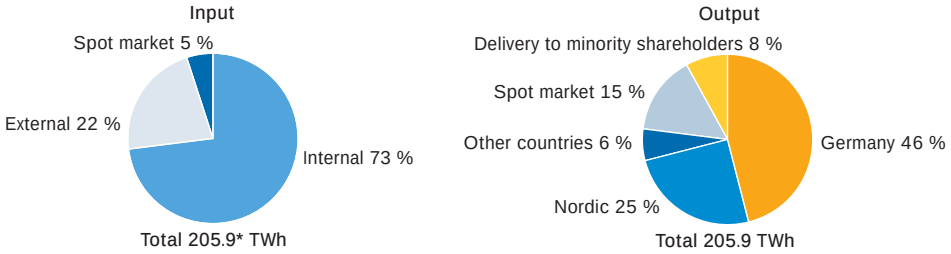
Vattenfall AB is the fifth largest electricity generator and the largest district-heating company in Northern Europe, with core activities in Germany, Sweden, Finland and Poland. Vattenfall operates in all segments of the electric value chain – generation, trading on financial and physical markets, distribution and sales (both business-to-business and to household customers). It generates electricity and heat and delivers energy to about 6 million customers in Europe. The Vattenfall group had a turnover of more than SEK 100 billion in 2002. The Vattenfall group generates around 160 TWh and sells 180 TWh of electricity per year. The annual production and sales of heat is 34 TWh. Vattenfall has a total of just above 34000 employees, of which 8000 work in Sweden, 500 in Finland, 22000 in Germany and 3000 in Poland. Vattenfall's vision is to be a leading European energy company.

For more information, see Vattenfall's Annual Report 2002

Electricity generation, Vattenfall total



Vattenfall's electricity balance 2002



** Adjusted for internal consumption*

Market position

	Sweden	Finland	Germany	Poland
Generation and sales	1	2	3	Among the 3 largest *
Electricity trading	Among the 3 largest		Among the 5 largest	N/a
Distribution	1	2	4	2nd after the Polish state
District-heating	2	Limited	1	1

* Only within sales.

VATTENFALL

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