Analysis of the efficiency of the German Electricity Market

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Preface

This thesis was performed in association with Norsk Hydro ASA, during the spring of 2005, at the Norwegian University of Science and Technology, NTNU, Department of Industrial Economics and Technology Management, section of Investment, Finance and Economic control.

We would like to thank Petter Longva, Henrik Sätness and the people at Norsk Hydro Oil and Energy for valuable comments and help throughout the process.

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Abstract

Summary

In this thesis, we present an analysis of the efficiency of the German power market. The thesis is done as an assignment for Norsk Hydro Oil and Energy. When we started to work on this thesis we had to figure out what defines efficient markets, and what we wanted to focus on. What most people probably associate with the term "efficient markets" is Fama's definition of efficient capital markets, where prices at all times are supposed to reflect all available information. Relating this definition to the German electricity markets, the question is whether electricity prices reflect all available information about the fundamental drivers and other factors that influence prices. However, this approach only addresses the information reflected in prices, and not the structural efficiency of the industry as a whole. Another, and probably better description of an efficient market come from Andrew Schotter's textbook on microeconomics: "Microeconomics- a modern approach" (2000). Here he defines the characteristics of a perfectly competitive market. Some of his important points are prices that converge to marginal costs, free entry to the market and perfect information. In a marginal cost analysis of German power prices, Felix Müsgens (2004), quantifies the extent of market power in the German electricity market by comparing a marginal- cost- based competitive price estimator with observed power prices on the German electricity spot market. The difference between marginal costs and prices is attributed to market power. Stochastic analyses identify a structural break between August and September 2001, dividing the observation period in two sub- periods. There is no evidence for market power in the first period from June 2000 to August 2001. Monthly prices are even slightly below marginal cost eatimates. However, there is strong evidence of market power in the second period from September 2001 to June 2003: on average prices are nearly 50% above estimates marginal costs. He find that mostly these price differences are in periods of high demand. Producer surplus based on EEX prices are also calculated; in the second period they are more than double compared to the competitive benchmark. He names increased concentration and learning effects leading to strategic bidding as some of the possible explanation for the increased use of market power.

Our first and foremost goal for this paper was that it could be of some use for Norsk Hydro, and since a marginal cost analysis for the German market had been performed, we chose ,after

discussions with Norsk Hydro, to focus on two other main issues regarding the German power market and efficiency.

Firstly, we perform an analysis of the overall structural efficiency of the German market, addressing the following question: Is the structure of the market such that it promotes competition, or is it on the contrary making it easy for the participants to use market power in order to extract additional profits and keep possible new entrants out of the market. This is an important question for Germany as a country because the industry, which is the bearer of the countries economy, is dependent on reasonable electricity prices to survive in a highly competitive environment. This qualitative analysis is presented in chapter 3, and focuses mostly on the competition analysis and congestion/cross-border trading. We start this analysis with the views of the European Union concerning the functioning of the German market based on several criteria. We come back to the most important results for this analysis later in this section.

The other main focus for this thesis is an analysis of the forward premiums in the German power market; the size, property, basis and development since the forward contract trading emerged at EEX. Supported by recent literature on equilibrium forward prices we argue that the forward premiums the electricity markets are a result of the overall hedging pressure of the market, and therefore will differ from market to market. Based on the conditions in the German market, and the theories on equilibrium prices in forward markets, we develop hypotheses regarding the risk premium in the German power market. In the short run we predict the forward price to be an upward bias to the expected spot price on average, this contradicts the findings from other commodity markets. We also predict seasonal variations in the risk premium, with a high positive premium in the period of high demand and skewed electricity prices, and a lower premium in periods of low demand and more stable prices. In the long run we expect negative risk premiums.

We also perform a spot price discussion, where we relate the most important occurrences related to the power market since 2000 to the spikes and possible structural changes in the spot prices. The main focus here is to see how this occurrences influence on the prices or if they influence at all, both in the short and the longer run. We also estimate the volatilities for the peak and spot prices, and compare them with the Nordic market. It can here clearly be seen that the prices in Germany are more volatile. Since Müsgens (2004) already had analysed the prices in relations to the marginal cost, and therefore the fundamental drivers, we only shortly comment the fundamental drivers in the German market and their development. Some of the distinctive characteristics concerning power prices are also discussed briefly and related to the German market.

Generally the power market's special features compared to other markets, makes it especially vulnerable for competition limiting behaviour. The small demand side price sensitivity causes big changes in price due to only small changes in supply. Also, as a consequence of the capacity limitation, even smaller companies have possibilities of exploiting market power in periods of high demand (by adopting their capacity to the demand). And the generally high barriers to entry makes it possible for companies to increase prices considerably without facing the threat of new entrants.

In addition, there are several special factors contributing to this picture. When the German market was opened, there were not appointed a regulator to ensure that this process went through, as it should. A key task of regulators is; to ensure that network operators do not earn excessive profits. With no regulator, and also most transmission system operators in Europe (4), there are excessive profit possibilities in the German market. The government and competition authorities have now appointed the regulating authority in the German power market to the Authorities for Postal services and Telecommunications, so it is yet to be seen whether this can make a change for the better, which it is supposed to. Another important issue for a well-functioning market is the balancing market; which EU see as out of line with norm or unclear for the German market. This is further investigated through our analysis.

Ideally, spot markets should have enough liquidity to give a reliable and transparent price signal. Meanwhile trading in the OTC market normally needs to be several times the volume of the actual consumptions in order for participants to trade without risking that particular individual transactions cause a shift in the market. Here, the German market has several problems. As the EEX is relatively new, the trading has not yet reached the volume in the spot that it should, only some 40 TWh are traded on this market place. In addition, only some 340 TWh are traded in the OTC market from a 500 TWh annual consumption. Some of the problems in the German market considering this are that the suppliers are obligated to supply the customers in their regions, so that a considerable part of the electricity sales is outside the markets.

Other factors, as cross-border auctions, turbulence and ownership in the German power companies are also discussed throughout the qualitative analysis.

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1 Introduction

The European power markets went through a significant change following the EU Electricity Directive of 1996. The liberalisation process throughout Europe took place in the last years of the 1990s, and Germany started theirs with the Energy Act of 1998. The development following this process is what is to be considered in this thesis.

The overall task is to analyse the efficiency in the German electricity market. In chapter 2, we shortly introduce the German Power Market and the European Energy Exchange, EEX. We briefly focus on some of the special factors in the German market. In chapter 3, we analyse this market qualitatively, considering four main issues; competition analyses, congestion analyses, company relations and market concentration, and ownership and competition. We try to focus on the issues relevant for market efficiency and describe possible methods to increase the efficiency in the German Power Market. Chapter 4 starts with an introduction to the distinctive characteristics of electricity spot prices and the fundamental drivers in the electricity market. We discuss the spot price development since the opening of the EEX and estimate volatility for comparison with the Nordic market. Chapter 5 describes future markets; the main functions and criteria for successful markets. Chapter 6 contains future pricing theory considering electricity markets. In chapter 7, we introduce some issues considering risk and hedging; the risk in the power market and the participants and their hedging needs. Here we set up the hypothesis to be tested in the empirical analysis. Chapter 8 contains the empirical analysis (hypotheses testing). We discuss the results from the empirical analysis and draw the conclusions in chapter 9.

2 The German Electricity Market

2.1 General

Germany is the EU's largest electricity market, with a consumption of some 500 TWh p.a., which is equivalent to 23 % of the European Union total. The German market is very pluralistic structured which is demonstrated by:

- 1100 electric companies operating in this market
- An electricity sector employing 130 000 people
- Generating an annual turnover of some 53 billion euro
- Supplying 44 million costumers in Germany
- Installed generating capacity of 105 000 MW
- Some 1,5 million km grid (see figure 2.1.1)
- High voltage grid integrated with the European interconnected grid (UCTE + CENTREL), which forms the basis for electricity trading with partners abroad
- 4 transmission companies
- 40 regional distributors
- Large number of electricity distribution companies

Figure 2.1.1 Circuit lengths in Germany (source: VDN, Facts and figures, 2004)

Circuit lengths in Germany

	low voltage*	medium voltage*	high voltage*	extra-high voltage*	total
total circuit length in Germany [in km]**	1,039,500	490,600	75,400	36,000	1,641,500

In 2002 the total net energy output excluding industrial power production was 484 TWh and mainly consisted of nuclear energy (31 %), lignite (29 %), hard coal (22 %), renewable energies (9 %) and natural gas (7 %). Some 10 % of fossil fuel based electricity is produced in cogeneration producing facilities. The ten largest German electricity suppliers in 2003 and their production is listed below:

Company	TWh/year
RWE AG	102,5
E.ON AG	85,2
EnBW AG	64,0
Vattenfall Europe AG	31,6
EWE AG	11,0
MVV Energie AG	8,3
GEW RheinEnergie AG	7,9
N-Energie AG	5,1
Stadtwerke Muenchen GmbH	5,0
Stadtwerke Hannover AG	4,9

Source: German Electricity Association (VDEW), Company data.

2.2 Structural changes due to deregulation

In 1996 and 1998, the European Council adopted directives aimed at opening the national electricity and natural gas markets of EU Member States to competition. Only beaten by UK and parts of the Scandinavian market, Germany was the fastest country in the Europe to open up its electricity market, with immediate 100 % full customer choice. The European Internal Market Directive for Electricity was incorporated into national law on 29 April 1998 by amending the Energy Industry Act (EnWG) that had originally been promulgated in 1935. Included in this directive were provisions regarding the organisation and functioning of the electricity sector, of how to provide equal market access for all players, and how to regulate the operation of transmission and distribution networks.

Prior to deregulation Germany had a three-level supply structure:

- eight supra-regional interconnected companies that produced 81 % of the total electricity production
- about 80 regional supply companies that produced 7 % of the total
- some 900 municipal supply companies (12 % of electricity production)

Supply monopolies were upheld by way of concession agreements providing suppliers with an exclusive right, and so called demarcation agreements. The concession agreements stated that the local authority granted the power company exclusive right to use public paths to lay electricity supply lines. In return the supplier was under an explicit obligation to connect new customers and supply existing ones. With the Energy Law in 1998 the antitrust exemptions for the energy sector were abolished and only grid was defined as an exception, hence supply and production were exposed to competition.

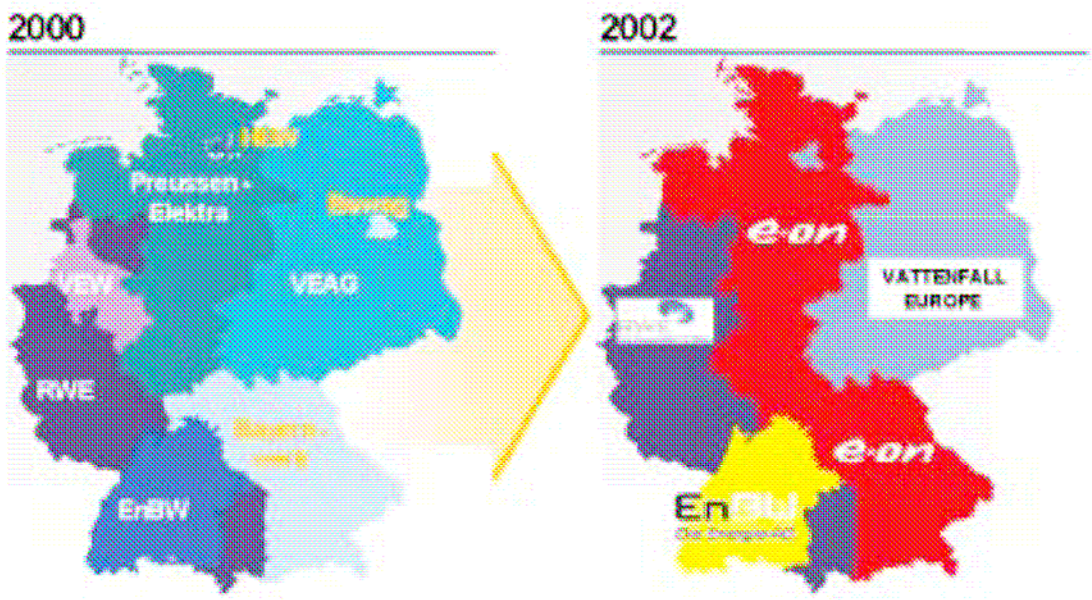
The deregulation process of the electricity market led to framework and market conditions resulting in strategic and structural changes within the participants, i.e utility companies. Former monopolists have resolutely implemented internal change programs to make their companies more competitive. German energy utilities have transformed into global players holding a variety of ownership stakes worldwide, and non-German energy companies have entered the German energy markets.

Market opening led to strong price competition that revealed excess capacity in electricity production and forced market players to involve in both rationalisation and restructuring programs. This led to a strong concentration process in the German market and profound structural change, which included 30 mergers (involving 80 companies) and 100 cooperation ventures (including 500 companies). The special part about this process was that when the large companies merged to retain competition position, the smaller companies began to cooperate and act jointly in order to gain market power. At the municipal level the trend was also Stadtwerke being sold to private utilities. The most important change in the German electricity utilities was though the mergers that took place between the leading energy suppliers, and reduced the number of supra-regional interconnected companies from eight to four, figure 2.2.1:

- The commission cleared the merger between VEBA and VIAG (Viag/Preussen Elektra and Bayernwerk) to E.ON Group (2000)
- The Federal Cartel Office cleared the merger between RWE and VEW (2000) and RWE continued to exist in name
- EnBW (Energie-Versorgung Schwaben AG and Badenwerk AG) (2000-2001)

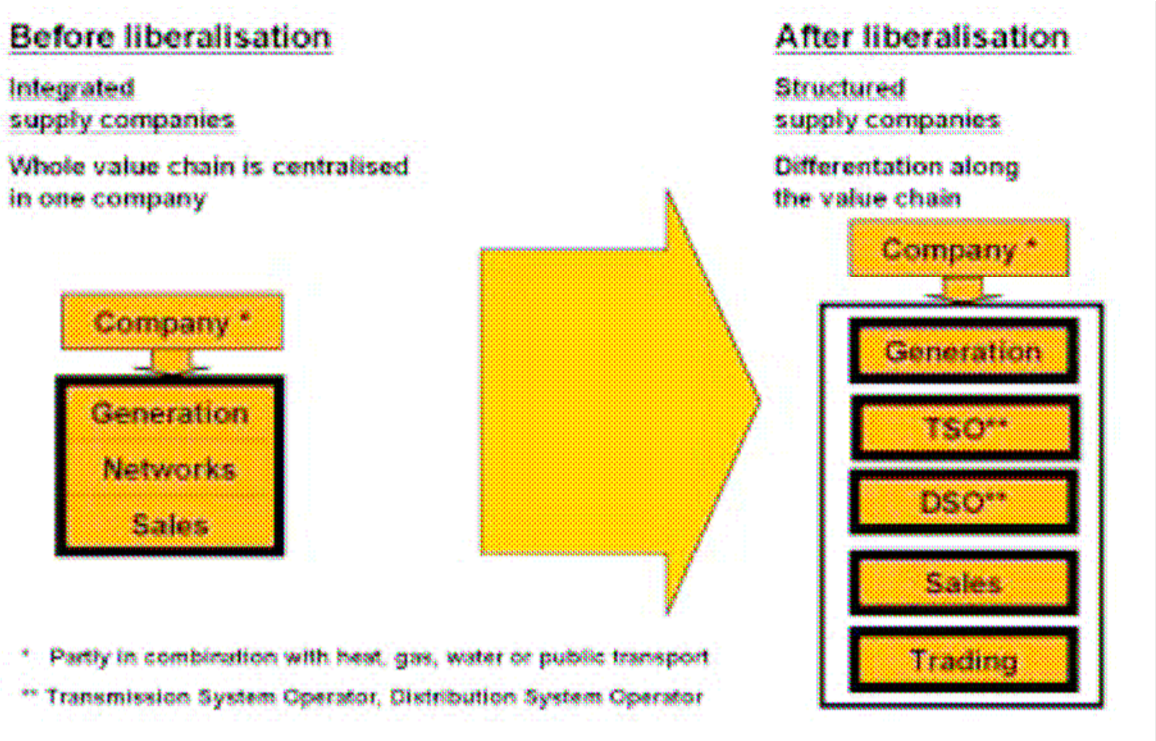
- Vattenfall Europe (Bewag, HEW, Laubag und VEAG) (2000-2001)

Figure 2.2.1: Mergers of the German interconnected companies (Source: "Electricity Market Report 2003" (EMR 2003), Vattenfall)



The companies E.ON and RWE control the majority of the German energy markets. A comparison with the situation before deregulation is presented in figure 2.2.2 to illustrate the change in the structure for the major companies, and their new possibilities for abuse of market power. More about market power in the German market is presented in another section.

Figure 2.2.2: Company structure before and after liberalisation (Source: "EMR 2003", Vattenfall)



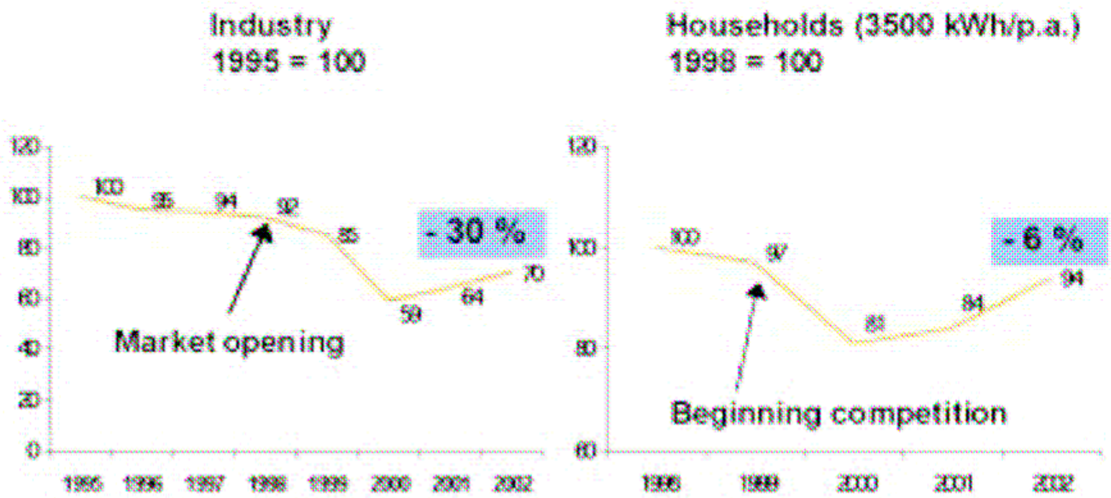
As a result of the liberalisation, the previously vertically integrated operations were split into its fundamental parts: Production, Wholesale, Trading, Transmission, Distribution and Sales. This led to a new market; the power trading market which is still developing (more about this later in the EEX chapter). The organisational structure of the companies is now changed to meet the legislator's demand of separating the accounts of natural monopoly activities (Transmission and Distribution) from those of competitive activities. This process is referred to as unbundling and also helped the companies to achieve higher levels of cost transparency.

2.3 Price development and components

The interest of the consumers is security of delivery and low prices. With the best quality of supply in Europe (only 15 min/year outage), the focus is on the latter. The main electricity consumers in Germany are the power intensive industry; aluminium, chemistry and paper.

Deregulation processes should lead to a decrease in the energy prices; when energy suppliers start to rationalise their company structures and benefit from efficiency potentials. Germany was no exception. Electricity suppliers believed that customers would change their supplier in large numbers, as was forecasted by empirical evidence, and companies restructured and concentrated. Following market opening the customers have benefited from price reductions, the industrial customers on average 30 % up to 2002 and households on average 6 % (figure 2.3.1).

Figure 2.3.1: Price developments 1996-2002 (Source: "EMR 2003", Vattenfall)

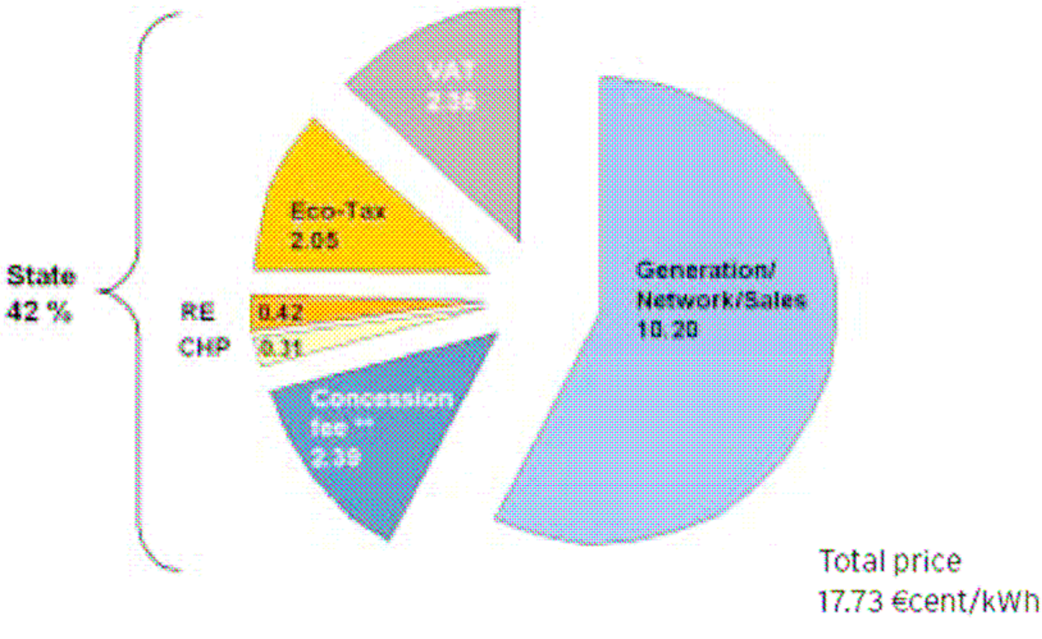


The changes however have not yet happened in the way predicted. Following a considerable reduction between 1998 and 2000, the prices began to rise again in 2001, striking both industrial end residential customers. The price increases have been explained in different ways; producers argue that the reasons for this rise is firstly due to increased fuel costs inducing higher production costs and secondly that they had to phase out considerable amounts of obsolete production capacity. The environmentally motivated political measures such as the Renewable Energies Act (Kyoto), the support of CHP (combined heat and power) and a gradual increase in the taxation of the electricity industry have in fact resulted in increases in consumer prices. Power suppliers had limited potential for further rationalisation to keep prices from rising and increases in costs were transferred to their costumers. The effect of increasing prices would, however, not have been as apparent unless tax rates, together with price add-ons from renewables' and CHP support, had increased as well.

It is worth noting that although the market is completely liberalised, companies are still obligated by law to offer a special tariff for household and small business customers, a system that is currently under review, since it is not really conform with the requirements of a liberalised market.

In Germany there is end-user price controls through the federal state authorities. The price of electricity can be broken down into a number of components. There is of course the actual price of electricity generation, but it also includes some government levies and taxes as well as cost reallocations resulting from legislation concerning the electricity market. They include a congestion fee an electricity tax, value-added tax and reallocations from the Renewable Energies Act and CHP act. In addition there will be a sales fee, if electricity is delivered through a supplier (non-bilateral contracts). Figure 2.3.2 shows the components of the electricity price for a household, where non-energy related charges amount to about 42 %.

Figure 2.3.2: Composition of the electricity price for residential customers ("EMR 2003", Vattenfall)



For residential customers, the use of system charge (for grid access) is regularly much higher than the electricity commodity itself. Given that they are connected at the lowest voltage level, the typical household is spending more than 80 % of the electricity bill on grid access charge and priority energy and taxes.

Prices (exclusive VAT and energy taxes):

Industry:
1995: Germany: 0,093 ct/kWh   UK: 0,0610 ct/kWh
2000: Germany: 0,065 ct/kWh   UK: 0,0612 ct/kWh

Household:
1995: Germany: 0,120 ct/kWh   UK: 0,0880 ct/kWh
2000: Germany: 0,101 ct/kWh   UK: 0,0800 ct/kWh

Source: Directorate general for Energy and Transport

2.4 What influences the German electricity price

There are several factors, both country specific and general for the electricity market, that influence the German electricity price:

- Strong concentration, more than 80 % of the installed capacity is controlled by the four major players. This is further treated in another section.
- Tariffs. EnWG continues the ex-post cost plus regulation, which gives no incentive to cost decrease and efficiency.
- CO2 emission trade. The electricity suppliers are, according to a calculation that will mean higher prices, collecting certificates.
- The EEX-forward market as reference price.
- Governmental fees and taxes
    - EEG: rise in 2004
    - Electricity tax: rise in 2003
    - Concession fee

The demand and supply is of course the major source of determination of the electricity price. These are depending on external factors such as weather (temperature and wind), fuel prices (especially coal and gas). More about the fundamental drivers in the power market is described later in this paper (chapter 5). We also do some price analysis in chapter 5.

2.5 Taxation

Various add-ons and taxes represent more than 40 % of the electricity price (Spiegel 33/2004, "Vier gewinnt"). In Germany the average energy tax is above 15 Euro/MWh, which is among the highest levels in Europe. The total taxation included in the power price is a result from mere components:

VAT: 16 %

Excise Taxes:

- Normal taxation – 100% in 2002 = 1,79 Eurocent/kWh (§ 3 StromSTG)
- Reduced taxation – 50 % = 0,9 Eurocent/kWh for night storage heater installed before April 1999 and public overhead cable buses and track transport (§ 9 Abs 2 StromSTG).
- Reduced taxation – 20 % = 0,36 Eurocent/kWh. For industrial sections; manufacturing, agriculture, forestry, fishing – livestock, for each kWh above a consumption of 26,8 kWh/year (§ 9 abs 3 StromSTG).
- No taxation for companies which use electricity for electricity production, which use electricity from renewable energy sources, which produce their own electricity (min demand 2 MW), which use electricity within a special contract called contracting, i.e. a contractor provides a company with functional energy e. g. steam, warmth, compressed air, cold or media like light, water or gas (§ 9 abs 1 StromSTG)

Municipal taxes

- Konzessionsabgabe 0,61; 1,32 – 2,39; 0,11 Eurocent/kWh
- Night (Schwachlast): 0,61 Eurocent/kWh

- Day:
  - Cities with up to 25.000 inhabitants: 1,32 Eurocent/kWh
  - Cities with up to 100.000 inhabitants: 1,59 Eurocent/kWh
  - Cities with up to 500.000 inhabitants: 1,99 Eurocent/kWh
  - Cities with more than 500.000 inhabitants: 2,39 Eurocent/kWh
- Special contract customers with an annual consumption of 30 MWh and a real demand of 30 kW in at least two months have to pay 0,11 Eurocent/kWh regardless of townsize

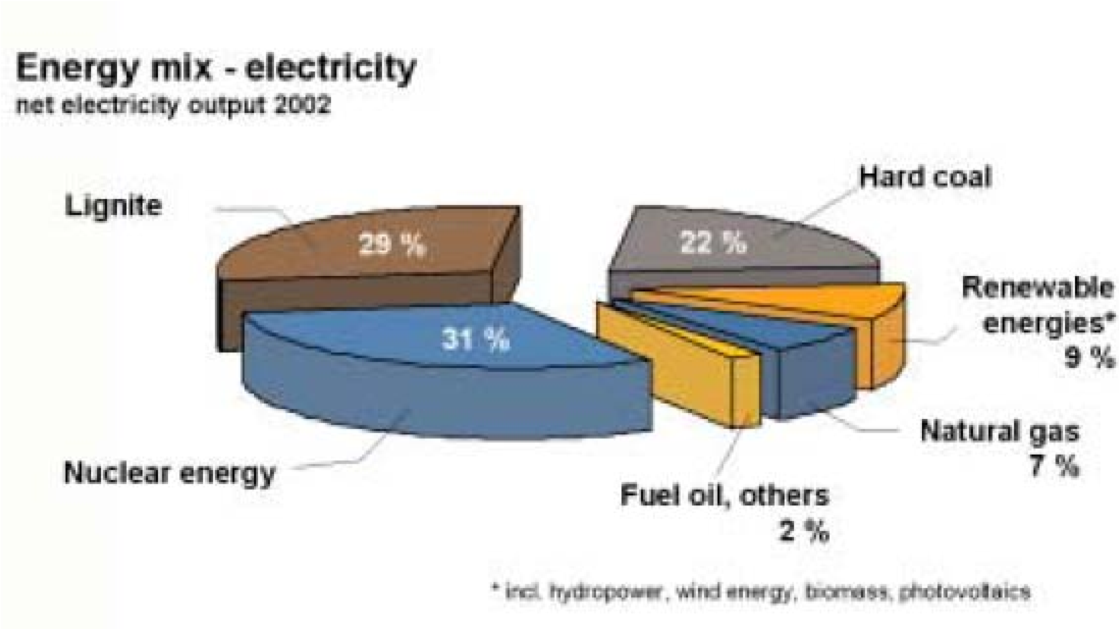
Energy/Environment taxes

- KWK: 0,19 – 0,26 Eurocent/kWh
- EEG: 0,18 – 0,39 Eurocent/kWh
- The charges differ from supplier to supplier. Some suppliers transfer these costs to their clients while some other suppliers definitely do not transfer the additional costs to their customers.

2.6 Energy mix and renewable energy

The German energy politics have focused on a good energy mix to secure quality of supply and for the German market to be less dependent on for instance Russian gas. The mix is shown in figure 2.6.1.

Figure 2.6.1: Net electricity output 2002 (Source: "EMR 2003", Vattenfall)



As a result of the policy to supply renewable energies through the Renewable Energies Act, there has been a rapid expansion of wind power in Germany. Today around 13800 wind mills with a capacity of some 12 GW are installed, which is contributing 5 % to electricity production, and more is expected to come. The development of the amounts of energy produced from renewable sources is shown in the following table:

Year	Total amount
2000	13 855 GWh
2001	17 818 GWh
2002	24 963 GWh
2003	29 387 GWh
2004	36 011 GWh

2.7 Nuclear decommissioning in Germany, phasing out nuclear power

Germany, which had 19 operating nuclear units in 2003, has decided to cease generating electricity based on nuclear energy. The “Law on the Controlled Phase-out of the Use of Nuclear Energy for Commercial Electricity Generation”, that came into force on 27 May 2002, fundamentally amended the Atomic Energy Act dating back to

1959. The purpose of this law changed from the promotion of nuclear energy to the controlled phase-out of its use. The amendment of the Atomic Energy Act was based on consensus on nuclear energy phase-out reached between the German Government and leading electricity generators in June 2001. The key points of the amendment are as follows.

- Ban on building new commercial nuclear power plants (NPPs)
- Limitation of the permissible service life of existing NPPs to 32 years
- Definition of maximum permissible remaining electrical energy for each power plant
- Possibility of transferring the electrical energy generated by older NPPs to younger NPPs
- Nuclear waste disposal is limited to direct final disposal. Delivery of irradiated fuel elements from nuclear power plants to reprocessing plants will be banned from 1 July 2005.
- Operators are obliged to build and use intermediate storage facilities for spent fuel elements at the NPP sites
- Mandatory reserve funds to meet the cost of nuclear incidents are increased tenfold to 2.5 billion Euro.

There is debate on the effects of nuclear energy, particularly considering the reduction of greenhouse gases. In Germany, nuclear energy alone enables the country to avoid emitting 160 million tonnes of CO2 every year (assuming replacing by coal- of lignite-fired generation). According to the Kyoto Protocol Germany and the other EU member states are obliged to reduce their aggregate emissions by 8 % by 2012 compared to 1990.

As a result of the phase-out of nuclear energy and the growing need for refurbishment of old plants, around 40 000 MW of conventional power generation capacity will have to be replaced by between 2010 and 2020. This means that on average one out of three power plants must be replaced at an estimated cost of 50 billion Euro.

2.8 European Energy Exchange

2.8.1 Development and Objective

The summer of 2000 saw the beginning of physical trading, initially at two German power exchanges, i.e. LPX (Leipzig Power Exchange) and EEX (European Energy Exchange located in Frankfurt). The two power exchanges merged on 1 January 2002, forming the European Energy Exchange (EEX) in Leipzig and this new exchange has set itself the goal of becoming Europe's leading power exchange.

The merger has increased transparency and created a stronger marketplace. Liquidity in the spot market (EEX) is steadily increasing. Today (2004), some 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, including both OTC and the exchange, which is three 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 players have a multitude of hedging possibilities available to them.

The point of origin is the operation of the German power exchange. The Auction Market gives the possibility of placing purchase and sales bid for single hours and block bids. The spot price determined on this market is a market price which is defined by way of bilateral participants, suppliers as well as by customers. Secondly there is also the Futures Market on which standardized contracts such as Futures, Forwards and Options are tradable. On the Futures Market Month, Quarter and Year contracts are offered. By this combination of Spot and Futures Market a complete risk hedging is possible. In futures; power, gas and other energy sources are to be tradable at EEX. In addition the trading opportunities will be completed by services related to the exchange, such as Clearing of transactions between market players (OTC Clearing).

2.8.2 Philosophy

The following criteria are essential for EEX when it comes to establishing a well-functioning marketplace:

- Liquidity
  Liquidity is the measure of success of the exchange. According to the information provided on the EEX' website, the EEX has in all its concepts chosen solutions which increase the liquidity of the markets.
- Transparency
  EEX follows the principle of transparency. All transactions and processes are registered by EEX so that the market operators can understand and anticipate the determination of prices. Transparency is a prerequisite for confidence and confidence is a necessary condition for trade.
- Equality of treatment
  A liberalised market should be an open market, according to EEX. Equal conditions for all participants ensure fair trading and also a prospering development.
- Simplicity
  All requirements and processes are made as simple as possible so that a wide range of players have access to the EEX markets. EEX considers itself a service provider and will therefore avoid unnecessary obstacles.
- Cost effectiveness
  Simple procedures and low financial requirements are the basis for a low cost structure. EEX wants to provide this for its customers. The approach is reflected by (EEX) low fees and low technical requirements.
- Gradual development
  The development must take place in a logical and successive way.
- Common ground
- Multi-dimensional diversification
  In the long run EEX sees itself as an integrated power exchange for Europe. There will be a development in terms of markets, products and regions.
- Building up a European network

2.8.3 The structure of EEX

In Germany, exchanges are unincorporated public law institutions. Therefore, the relations between the exchange and the trading participants are governed by public law. The exchanges are based on the German stock exchange act, and the supervision falls within the responsibility of the individual federal states.

The bodies of EEX are Management, Market Surveillance and the Exchange Council. Some important tasks for management are to grant companies and traders with licenses, regulating the organisation, the course of business and the trading time on the exchange, monitoring and checking compliance with the rules and regulations and of publishing of prices. The Market surveillance office monitors trading and the settlement of transactions on EEX. It records data on trading and settlement automatically, and then evaluates and carries out investigation activities, which might be required. The Exchange Council is in charge of establishing the rules and regulations and of appointing the managing directors and the head of the Market surveillance office in accordance with the exchange supervisory authority as well as of monitoring the management board.

2.8.4 EEX Spot Market Concept

The framework conditions concerning the European market and leading to an increasing demand for efficient management tools, such as power exchanges, can be summarised:

- Since the deregulation directive, the development of the common European market has been characterised by increasing competition and the emergence of risk such as the price and the counterparty risk.
- In addition, trading of rights for the emission of greenhouse gases were introduced within the EU in 2005. EU here wants to use the market mechanisms to reduce their emissions of greenhouse gases in accordance to the Kyoto Protocol. Since in Germany, power is generated to a considerable degree by means of the use of primary energy carriers emitting CO_2 (lignite,

mineral coal, natural gas, mineral oil), the markets for power are closely interrelated with the markets for EU allowances.

2.8.4.1 Products on the Spot Market of EEX

Spot contracts for power can be traded on the spot market of EEX. The spot contracts can be divided into hour- and block contracts according to the duration of the delivery. In the case of hour contracts, the delivery of electricity of a constant output over a given delivery hour is traded, and similar for the block contracts. The following deliveries are traded as block contracts:

- Daily base load deliveries for each day of the week (0:00 am until 12:00 pm)
- One daily peak load delivery for each day of the week (08:00 am until 08:00 pm)
- One weekend base load delivery for each weekend

The contract volume of a contract in MWh is established with the formula:

Contract volume [MWh] = Delivery capacity [MW] x Number of delivery hours [h]

On EEX spot contracts for EU rights for the emissions of greenhouse gases (EU allowances) can be traded. These EU allowances grant the owners of a plant in a EU member state the right to emit one tonne of CO_2 during the first commitment period (2005-2007). Other greenhouse gases are also included in the EU allowances, and are converted into CO_2 equivalents in accordance with their contribution to the greenhouse effect. The contracts for EU allowances have a contract volume of 1 t CO_2 and are traded in EURO/CO_2 to up to two digits.

2.8.4.2 Application of the spot contracts

A balance between the generation and consumption of power and the emissions and the EU allowances has to be ensured at all times (after the settlement period for the emissions/allowances), since power is a non-storable commodity. As a consequence, an important function of the EEX Spot Market is to facilitate trading in short-term standardised power and EU allowances products. This gives the trading participants the possibility of ensuring a balance of their sales and procurement requirements.

Spot trading is also used for the purpose of optimisation of generation plants and delivery contracts. If the production cost of a plant is higher than the spot price, the company can rather buy spot electricity to meet their contracts, than to produce.

2.8.4.3 Trading and trading accounts

On the spot market of EEX trading participants, traders, trading accounts for hour contracts and so-called sub-groups are differentiated. A trading participant is defined as a company, which is licensed for participation in spot trading on EEX. A trader is defined as an employee of a trading participant who is licensed to participate in spot trading on EEX. Trading of block contracts on power as well as of spot contracts on EU allowances is executed separately for each trader; the EEX system assigns precisely one trader to each buy or sales order.

2.8.4.4 The daily trading process

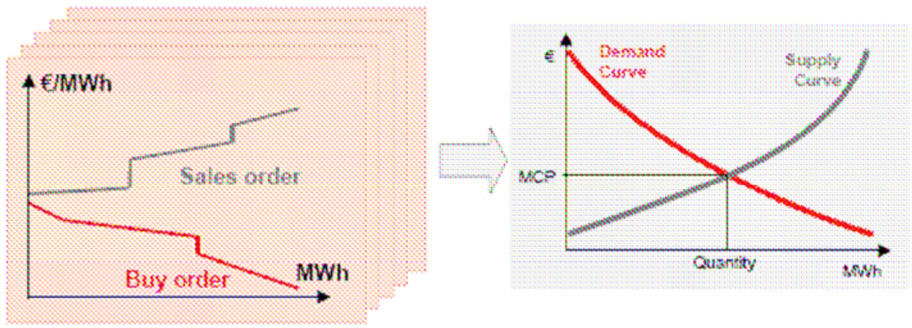
The daily trading process is summarised in figure 2.8.1.

Figure 2.8.1: The spot daily trading process (Source: www.eex.de)

2.8.4.5 Pricing

The pricing mechanism of EEX spot market is described in figure 2.8.2.

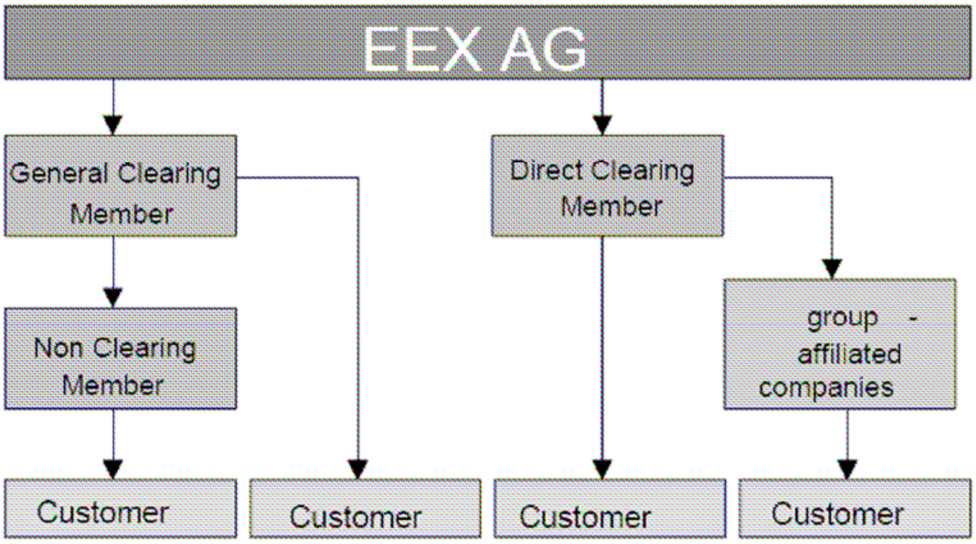
Figure 2.8.2: Pricing mechanism of EEX spot (Source: www.eex.de)



2.8.4.6 Settlement and clearing

The clearing structure of EEX is described in figure 2.8.3.

Figure 2.8.3: Clearing structure of EEX (Source: www.eex.de)



2.8.5 EEX Derivatives Market Concept

2.8.5.1 Principles of the Derivative Market

Principle of liquidity
Liquidity is primarily defined as the number and the volume of the futures contracts traded. Also, high liquidity exists if there is a corresponding market depth. The benefits are several, if liquidity is high, it is possible to open or close major positions cost-efficiently at any time, hence a contribution to reduction of price and volume risks.

Principle of transparency
Buy and sell orders are disclosed to all trading participants so that there is a fair distribution of information. This gives the participants the possibility to respond to imbalances between supply and demand immediately.

Principle of practicability
The electronic trading and clearing system of EEX gives equal and geographically independent access to all trading participants. The security of this system is well

known after it has been used for several years on the financial market, and there are possibilities for integration with company-owned IT systems.

Principle of anonymity
The trading and clearing processes on the EEX Derivative Markets are anonymous, which means that the other trading participants do not know which buy and sell orders the individual participants place at any given time. Information on prices and volumes is always provided without naming the parts involved.

2.8.5.2 Risk management

The main purpose for having a derivative markets is the possibility for risk management, and EEX Derivative Market helps the participants in managing the following risks:

- The market price risk
- The counterparty risk
- The volume risk
- The basic risk
- The liquidity risk

More about the risk that the activities of power economics bring is discussed later in this paper.

2.8.5.3 Motives of the trading participants

In principle, derivatives can be traded for three reasons:

- Hedging: Futures can be used to hedge for falling and increasing prices, and options can also be used for hedging
- Arbitration: Arbitration uses differences in prices between e.g. futures, traded in the exchange and other contracts, traded of the exchange
- Speculation: Speculators assume risks and provide liquidity for trading participants with contrary market strategies in both futures and options.

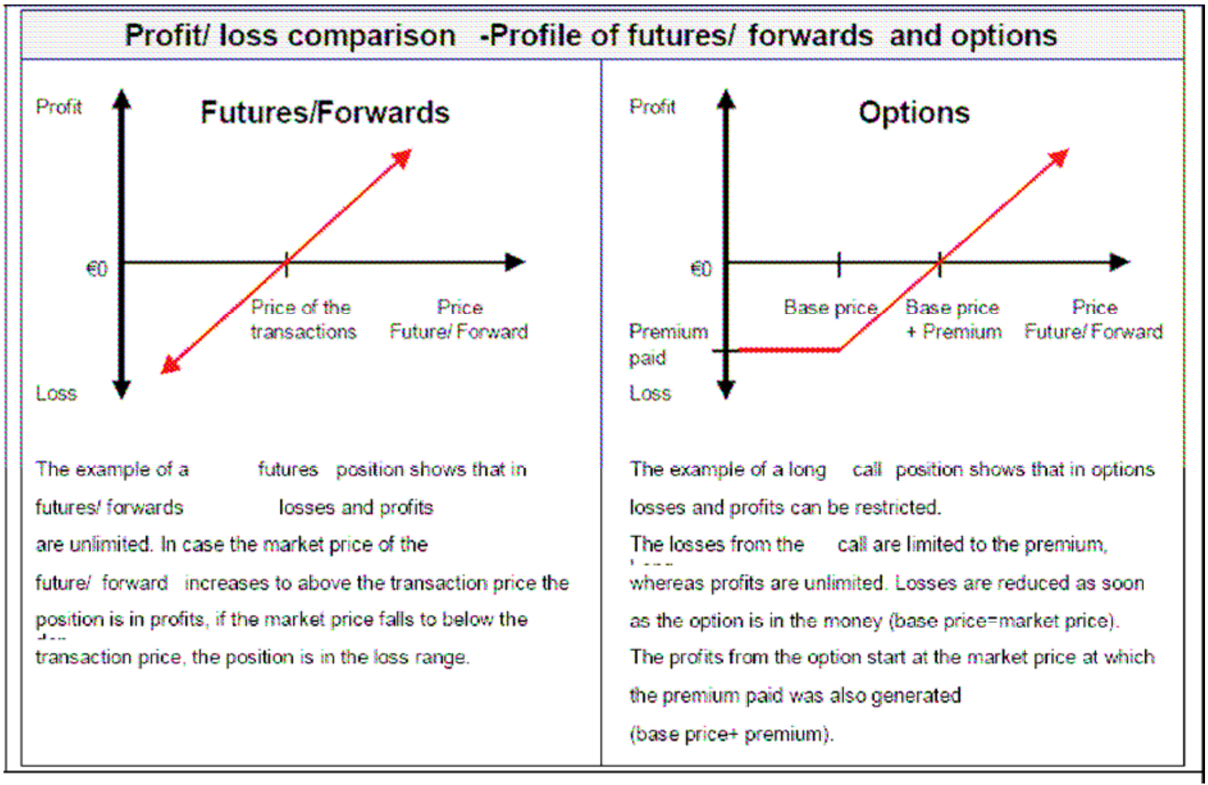
2.8.5.4 Difference between futures and options

This is described in figure 2.8.4. The risk-return profiles are shown in figure 2.8.5.

Figure 2.8.4: Differences futures-options (Source: www.eex.de)

Unconditional forward transactions (futures transactions)	Conditional forward transactions (option transactions)
Obligation to buy or to sell a specific underlying security at a price established today at a specific point of time in the future.	**Right** to buy (call option, call) or to sell (put option, put) a specific quantity of an underlying security at a price established today (exercise price) on the last day of trading (European option) or until the last day of trading (American option).
- Unrestricted risk of loss - Unlimited profit potential - Neutralization of risks - No payment of premiums	- Restricted risk of loss for the buyer, unrestricted risk of loss for the seller - Very high profit potential - Insurance against risks - Payment of premiums

Figure 2.8.5: Risk-return profile, futures-options (Source: www.eex.de)



2.8.5.5 Future products on the EEX and their features

The following futures can be traded on the EEX Derivatives Market:

- Phelix Base Futures (cash settlement)
- Phelix Peak Futures (cash settlement)
- German Base Load Futures (physical settlement)
- German Peak Load Futures (physical settlement)
- French Base Load Futures (physical settlement)
- French Peak Load Futures (physical settlement)
- Dutch Base Load Futures (physical settlement)
- Dutch Peak Load Futures (physical settlement)

These futures are characterised by the following product features [EEX]:

- Delivery period: months, quarters, years
- Load profile: rate of delivery
- Place of delivery: TSO zone
- Contract volume: rate of delivery x delivery days x delivery hours/day
- Tradable delivery periods

- Maturity: occurs on the last day of trading of the respective futures contract
- Quotation: in EURO per MWh, two decimal digits
- Daily profits and loss settlement (variation margin)
- Fulfilment
- Final settlement price
- Additional margin

2.8.5.6 Fundamental principle of options on futures

The following options on futures can be traded on the Derivative Market of EEX:

- Phelix Base Option (option on Phelix Base Future)
- Phelix Peak Option (option on Phelix Peak Future)

An option on a future is an agreement with a specific futures contract underlying the option, a specified quantity, an agreed time (last day of trading), and an agreed price (exercise price). This can either be bought (call option) or sold (put option). The seller of the option undertakes to sell the underlying asset for the exercise price agreed on (call) or to buy (put) provided the buyer exercises his right. The option price (premium) comprises two components; the intrinsic value and the time value (option price = intrinsic value + time value)

The options are characterised by the following features:

- Fulfilment
- Exercise
- Margins
- Assignment
- Premium margin
- Additional margin
- Quotation
- Types of options
- Tradable underlying securities
- Maturity
- Option series

- Contract volumes

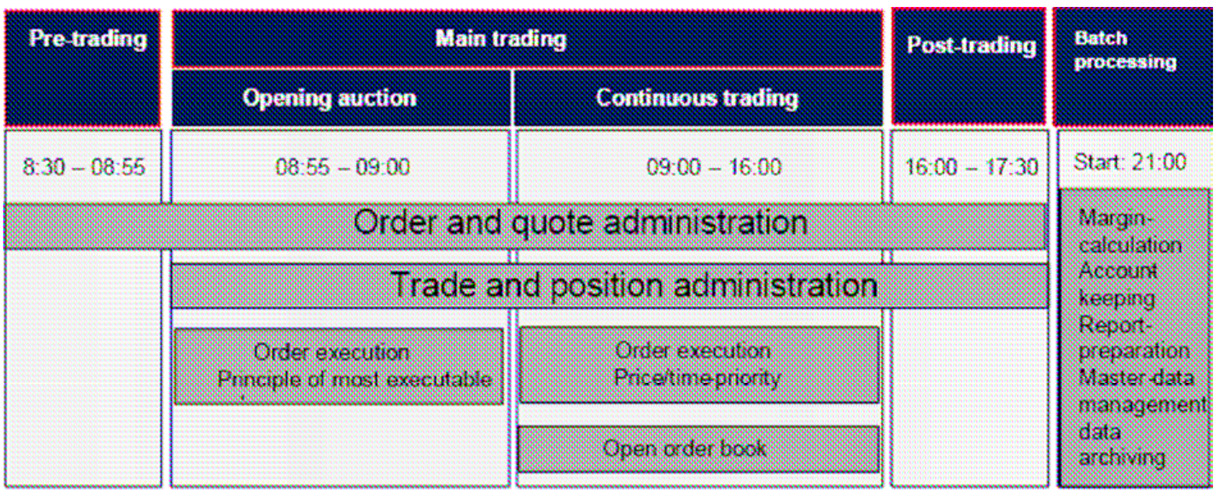
2.8.5.7 The daily trading procedure

The daily trading procedure and the phases are described in figure 2.8.6. The trading day is shown in figure 2.8.7.

Figure 2.8.6: Daily trading procedure (Source: www.eex.de)

Pre-trading	Main trading: Opening	Main trading: Continuous trading	Post-trading	Batch processing
• Placing, changing, cancelling of orders and quotes possible. • Prices not displayed.	• Placing, changing, cancelling of orders and quotes possible • Indicative price and indicative surplus displayed and updated • Market makers have to place quotes • Opening price established according to the principle of most executable volume • Exercise of options • Registration of OTC transactions	• Placing, changing, cancelling of orders possible • Every new order is immediately checked for feasibility compared to orders on the opposite side of the order book • Order execution according to price/ time priority • Order book is open – market depth is updated immediately • Execution confirmations are transmitted immediately after the transaction • Functions to avoid extreme price fluctuations which do not correspond to the current situation on the market • Exercise of options • Registration of OTC transactions	• Placing, changing, cancelling of orders possible • Prices are not displayed • Market control changes to batch processing • Registration of OTC transactions	• System not available for participants • Account keeping activities • Data archiving • Master data management • Preparation of reports • Margin calculation

Figure 2.8.7: The EEX trading day (Source: www.eex.de)



2.8.5.8 Pricing

The continuous trading pricing can be seen in figure 2.8.8.

Figure 2.8.8: Continuous trading pricing (Source: www.eex.de)

Incoming order	Existing orders on the opposite side of the order book: Market order	Limit order	Market order and limit order
Market order Buy	Reference price	Lowest sell limit	Reference price or sell limit (minimum)
Market order Sell	Reference price	Highest buy limit	Reference price or buy limit (maximum)
Limit order Buy	Reference price or buy limit (minimum)	Lowest sell limit	Reference price or buy limit (minimum)
Limit order Sell	Reference price or sell limit (maximum)	Highest buy limit	Reference price or sell limit (maximum)

2.8.6 Volume statistics for the EEX

The development of the trading on the EEX is shown in the next three figures (2.8.9-2.8.11). As we can see there has been a steady increase since the start of the trading on the two exchanges back in 2000.

Figure 2.8.9: Development spot volumes EEX, 2000 - 2005

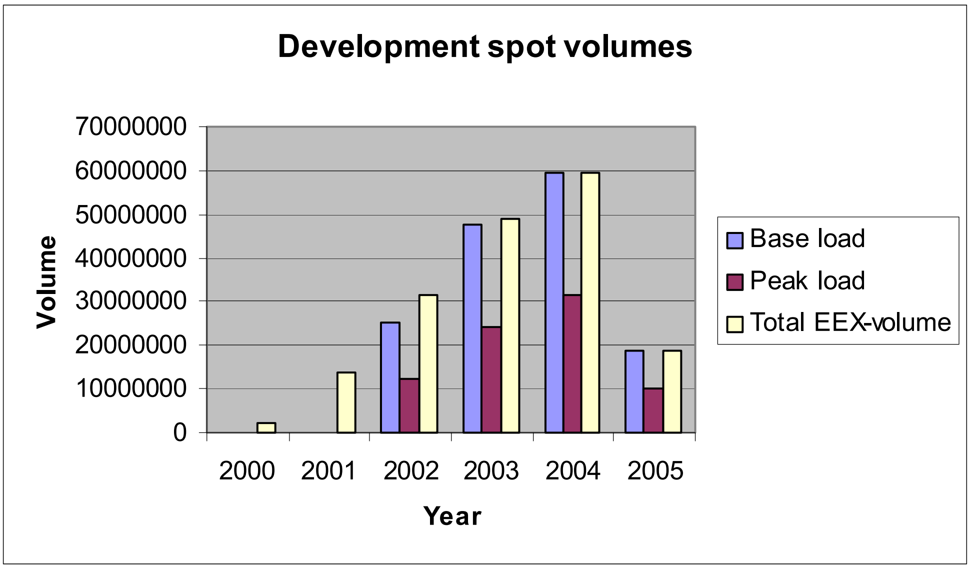


Figure 2.8.10: Development futures volumes EEX, 2000 - 2005

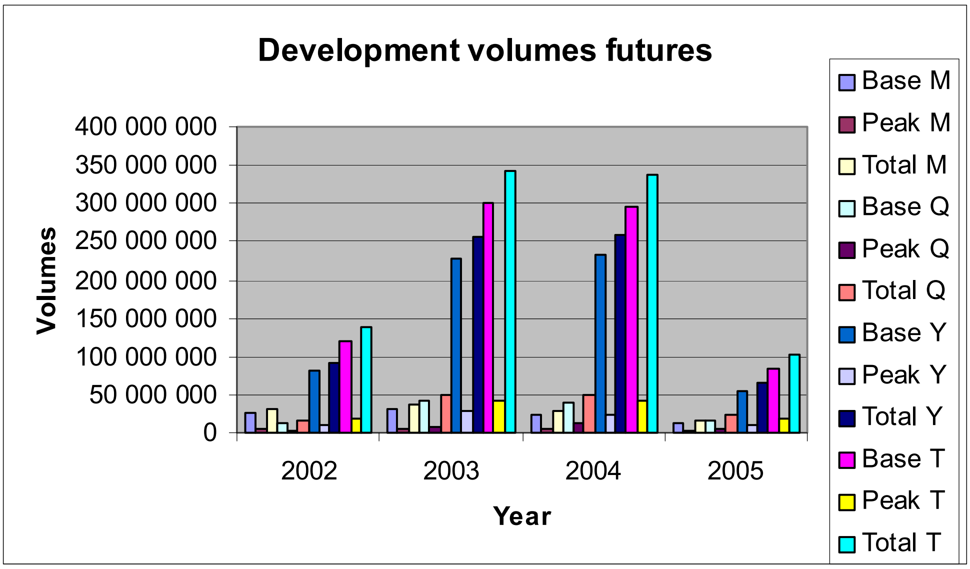
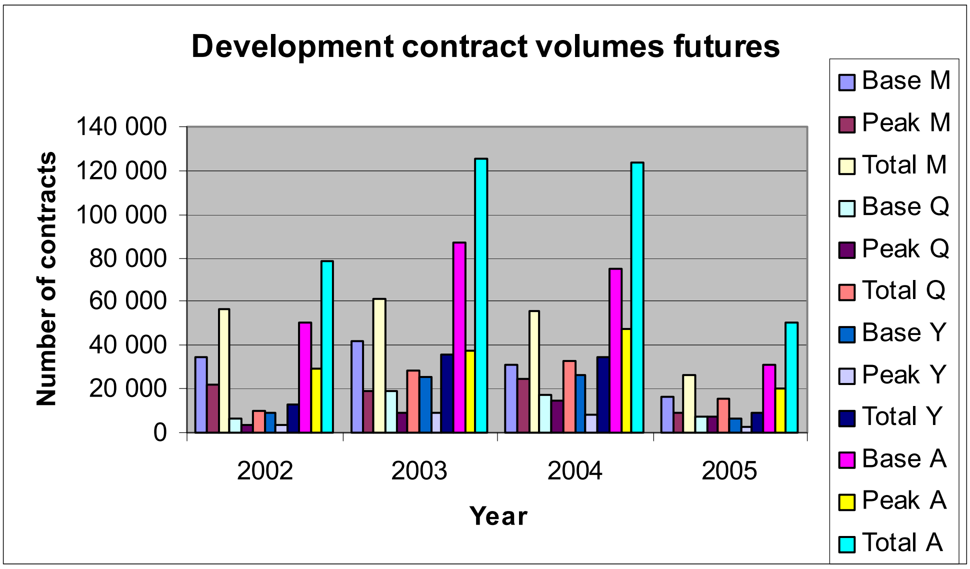


Figure 2.8.11: Development number of future contracts EEX, 2000 - 2005

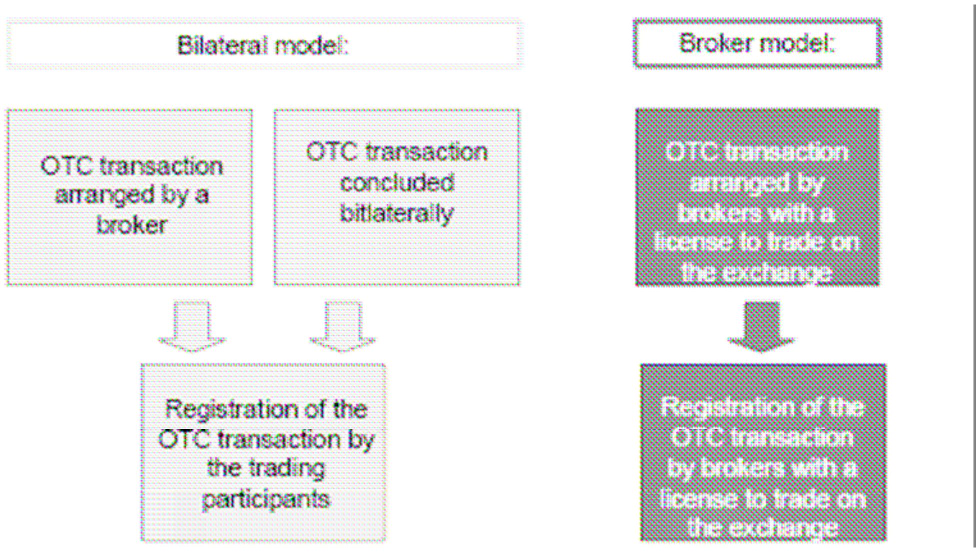


2.9 OTC Market on the EEX (Over the counter)

A large part of the electricity futures transactions is still concluded bilaterally as in the past. This will continue, as the over-the-counter future transactions will supplement the EEX Derivatives Market. Therefore, the market participants are not always interested in the anonymity of futures trading on the exchange, because they can draw conclusions regarding the market development from the disclosure of the contractual partners. High volume contracts are very seldom placed in the order book of an exchange, because such disclosure of high demand can effectuate the market price unfavourable. It is only possible to trade over the counter with market participants who are not authorised for futures trading on EEX.

Since many OTC transactions, because of the credit status of potential contract partners, are not concluded, EEX offers the opportunity of assuming the counterparty risk for standardised OTC transactions, by placing the clearing members as contractual partners between the buyer and the seller. More than 80 % of today's OTC transactions can be registered for OTC clearing at EEX in this way. This gives both higher liquidity and higher trading volumes.

Figure 2.9.1: The business model regarding the registration of OTC transactions (Source: www.eex.de)



3 Qualitative analysis

According to Andrew Schotter (2000), an industry composed of price taking firms constitutes a perfectly competitive market. This type of market has the following characteristics:

1. There are many firms, each of which has an insubstantial share of the market.
2. There is free entry to the market. No barriers exist to prevent entry.
3. There is a homogenous product. All firms in the industry produce exactly the same product.
4. There is perfect factor mobility. The factors of production (that is, capital and labour) are free to move between this industry and one or more other industries.
5. There is perfect information in the sense that all participants in the market are fully informed about its price and about its profit opportunities.

In such a market price will converge on marginal cost as the number of firms in the market grows, and they become price- takers. This is significant because we know that setting a price to marginal cost maximizes the sum of the consumer surplus and the producer surplus in the industry.

Following this definition it is obvious that the German electricity markets does not constitute a perfectly competitive market. First, in chapter 3.1, we see that several firms in the German power market definitely have a substantial share of the market (as also is seen in chapter 2), and you can definitely raise the question if they are really price takers. There is also most definitely not free factor mobility and free entry to the market, as we can see in section 3.2.

The following analysis is based on the structure of the paper ”Kraft og Makt” (Bye, Von der Fehr, Riis, Sørgard, 2003). We have tried to analyze the German Market in the same way as this paper analyzes the Norwegian Market, adapting the analyses to focus on the main issues in Germany. The four main parts are; competition analyses, congestions, company relations and market concentration, and ownership and competition.

3.1 Competition analysis

This chapter is an evaluation of how the situation is today and the expected development for the years to come. Here we focus on dominating market participants, the situation in the German power market and changes in governmental regulation.

The only way to fully understand how a market function, is through thoroughly evaluating the incentives for competition existing in the particular market (von der Fehr 1998). This framework includes both evaluating the targets of the competing companies, the choices they have and the consequences different choices will have for future opportunities. An important issue in this respect is whether the regulating framework set by the authorities discipline the companies, or on the contrary give incitements to adapt in a society economical inefficient way. An example of this is if a company within an industry have an opportunity to use market power and earn excessive returns doing so.

3.1.1 EU view on the implementation of the Electricity Market

The next chapter is based on figures and information from the “Annual Report on the Implementation of the Gas and Electricity Internal Market” (EU, 2005). The German electricity market is 100 % open with a size of 500 TWh. According to the price comparison, we can see from figures 3.1.1 and 3.1.2 that both for the electricity and gas market (for comparison), the prices in Germany are higher than the average in the European countries.

Figure 3.1.1: End-user electricity price comparison: July 2004 (Source: EU, 2005)

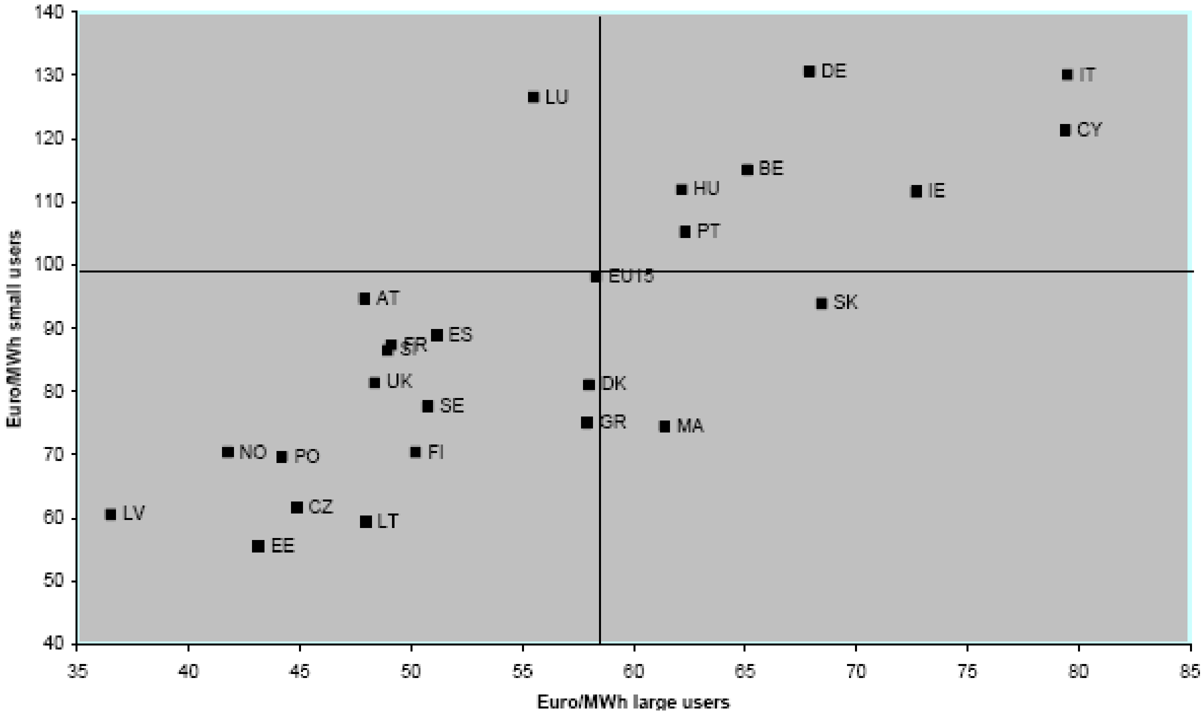
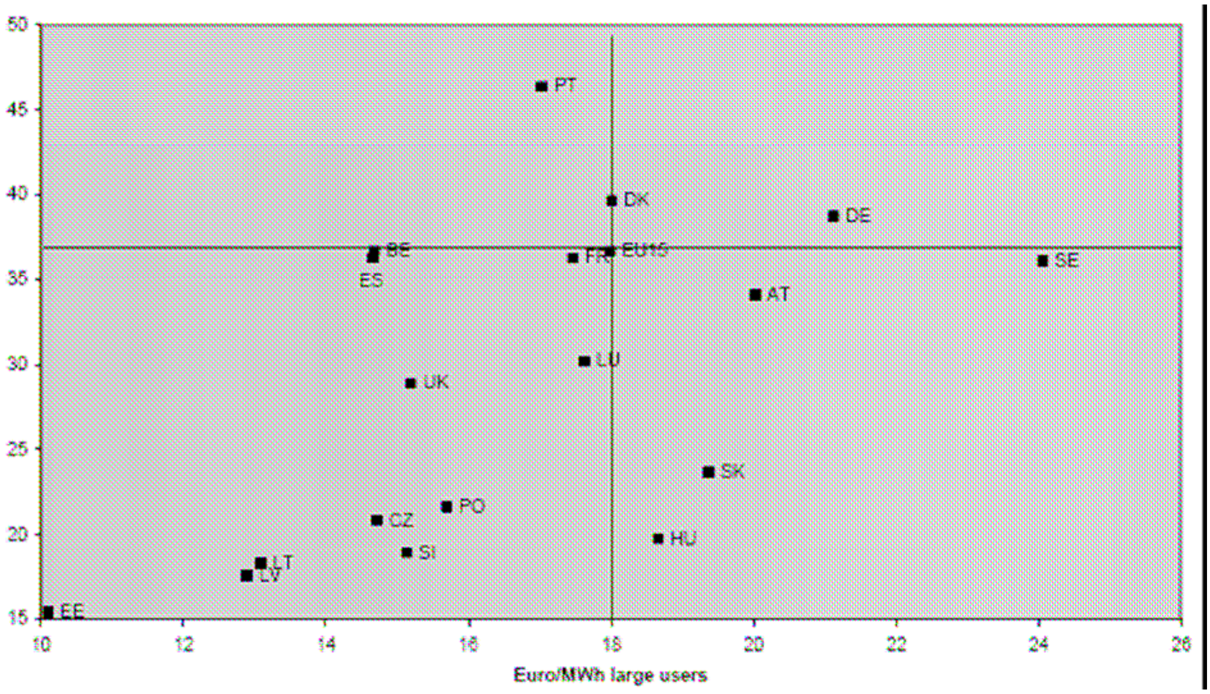


Figure 3.1.2: **End-user gas price comparison: July 2004 (Source: EU, 2005)**



With the market opening, the possibility for switching supplier increased significantly, and since the market opening 35 % of the large industrial users (annual consumption of at least 1 GWh each) and only 6 % of small commercial participants. The remaining 65 % of the large industrials and approximately 25 – 50 % of the smaller have renegotiated with their existing supplier.

3.1.1.1 Unbundling and network access

Fair network access conditions are crucial for the development of a competitive market. In order to ensure this, the new EU Directives require regulation of the methods used to set charges for physical network access as well as for the ancillary services (such as the provision of balancing energy), and also regulation of methods for the legal and functional unbundling of both transmission and distribution network operators. In Germany the TSO is legally unbundled and the degree of management unbundling is also relatively high, which means that Germany is compliant with the requirements of the Directive.

Strict rules on unbundling are required to ensure fair and cost reflective charges. That means that a key task for the regulator is to prevent excessive profits from the network operators. Another task is to ensure that the tariff structures are non-discriminatory. In Germany there are four transmission companies and about 950 distribution companies. It appears to be some divergence, which is reflected in the differences in distribution charges.

3.1.1.2 Balancing

Because in some cases there will be differences between the quantities of power injected to the network and the amount used by the customers, there is a need for provision of balancing energy. This service is managed by the TSO, which uses the generators in the market to provide the needed back up. There are in EU two main models for trading of electricity on the wholesale market, which affect the organisation of the balancing market. The first is based on bilateral contracts and a "net pool" managed by the TSO, where market participants can get extra energy to balance their contracts. The second, used in Spain, is that all the exchanges are connected via a "mandatory pool" where all the energy is bought.

The German balancing market is based on the first model, with a balancing period of 15 minutes. The charges are set by the market and the balancing is regional (in the regions there exist single dominant generators as known). The graphs below shows the difference between the amounts paid to and by the TSO for balancing energy. These prices should not be very different if the market is to be well functioning.

According to the EU, Germany both have network tariffs out of line with normal (tariff significantly above 15 EUR/MWh for large users connected at medium voltage and significantly above 40 EUR/MWh for small users connected at low voltage) and balancing in the category “out of line with normal or unclear”. There is room for improvement.

3.1.1.3 Competition in the Electricity Sector

A successful competitive market has better chances of developing when a sufficient number of participants both in the generation and supply are present. The key to the overall market structure is the generation sector. There is today a general tendency for integration between generation companies and supply companies for hedging purposes.
Where generation is concentrated, it is likely that the switching possibilities are limited. This also gives incitements for market power. Another important factor for a well-functioning market is to establish a liquid wholesale market, which offers the possibility for companies to purchase and sell electricity on reasonable terms.

For Germany 39 TWh was traded on the EEX in 2004, while 342 TWh of the total consumption of 499 TWh was traded bilateral. Ideally, spot markets should be liquid enough to give a reliable and transparent price signal. Trading in the OTC markets normally needs to be several times the volume of actual consumption in order for the participants to trade without risking that particular individual transactions cause a shift in the market. As we see, there is a need for more liquidity in the spot market and also bigger volumes to be traded on the OTC market.

3.1.1.4 Interconnection and development of regional markets

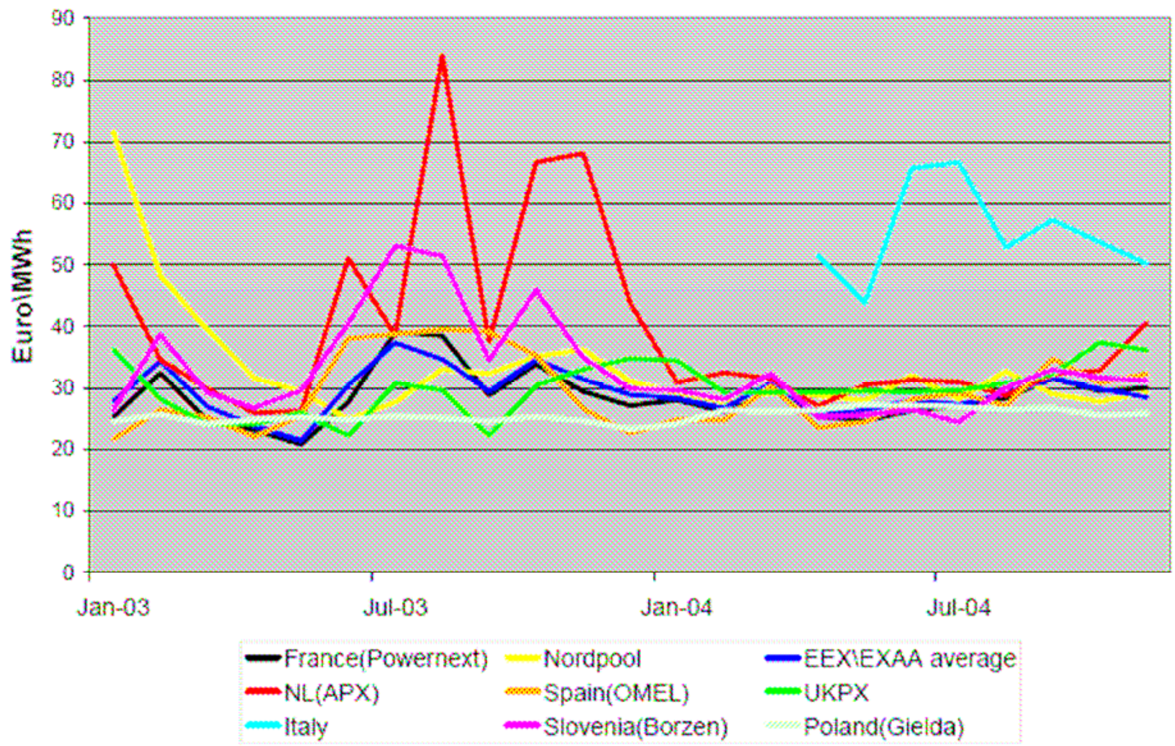
To avoid some of the problems associated with an inappropriate market structure, it would help to build larger markets. In that way the market positions of E.On, RWE, EnBW and Vattenfall will be reduced. This requires additional infrastructure as well as consistent rules concerning capacity allocation.

The current level of interconnection capacity is at a rather low level. In Germany the installed generation capacity is 109 GW and the import capacity is 12,2 GW, which is 11 % of the installed capacity.

3.1.1.5 Current market structure

Successful markets, such as the Nordic, have between five and ten major competitors in addition to a large number of smaller companies in the generation sector. Under these conditions, there appears for the customers to exist a competitive market. The largest producer in Germany, RWE, controls about 30 % of the capacity, while the four largest controls ca 81 %. Another problem is that new market places are often characterised by continuation of long-term power purchase agreements. In graph 3.1.3 we see the price developments in some markets between July 2002 and November 2004.

Figure 3.1.3: Wholesale electricity prices: day-ahead spot (Source: EU, 2005)



The integration of individual electricity markets contributes greatly to consumer confidence, and will lead to an increase in the liquidity of the wholesale markets, greater price credibility, and a larger range of alternative contract structures.

One of the tasks of the competition authority, often in cooperation with the regulatory authority, is to monitor price developments and their reasons, because price increases are always likely to be questioned by the consumers and there may be concerns about market power. The regulator in Germany is not fully developed and there have been few investigations by the authorities.

According to the European Unions listings, Germany is in a middle-group with three to six significant market players both on the generation and supply side.

3.1.1.6 Security of supply

The security of supply is in the evaluation monitored in the following parameters, with the values for Germany:

- The lowest monthly value of the reserve capacity during 2003: 3,2 GW

- The forecast for the same capacity in 2005: 4,5 GW
- Reserve capacity as % of generation capacity: 5 %
- Import capacity as % of generation capacity: 14 %

These numbers indicate that the security of supply in Germany is quite good for the time being. However, there has not been implemented any capacity support mechanism, and the market is based on the energy price (except for the renewables as discussed earlier).

3.1.1.7 Public services and the protection of consumer rights

In Germany there exist both universal service and a "supplier of last resort". The universal service is defined as the "right to be supplied with electricity of a specified quality within their territory at reasonable, easily and clearly comparable prices" (Directive 2003/54/EC – Art. 3).

The Supplier of Last Resort (SOLR) is a necessary fallback position to protect customers in the case of:

- Bankruptcy of the current supplier
- Supply of vulnerable customers, being unable to pay
- Supply to Remote customers

There is also a social welfare system for vulnerable customers, and a security system for compensation to the supplier. The household customers are protected by system of ex-ante price controls using regulated tariffs.

For the customers it is possible to compare prices on the suppliers website, and there is no charge for switching supplier. However, there is no formal procedure for settlements of disputes and there is no formal set time for response after complaints. The consumers are positive of both prices, access, information and consumer service and have a fair attitude to the terms and condition. (The study "European Consumers and Service of General Interest" financed by DG SANCO).

3.1.2 Sources of profitability

The use of market power is only possible if scarcity of supply exist, that means a limited number or no one else offer the same service. There are several reasons this situation could occur: limited access to the natural resources needed for production, technological knowledge, distribution systems and customer relations. If the company has no such exclusive access, a profit potential do not exist. But if the company owns a scarce resource theoretically a monopoly profit could be retrieved exercising market power. Consequently will our first step analysing incentives in the German power market be a search for exclusive opportunities for profit in the market.

In the power business there are very limited opportunities for developing a competitive advantage through superior product quality or superior technical systems due that the technology in use is widely known. The fact that electricity is a homogenous good adds to this. There are however three sources of profitability:

1. Limited capacity, location and interest rate for production
2. Vertical integration between distribution and retail
3. Costs connected to change of supplier

3.1.2.1 Capacity

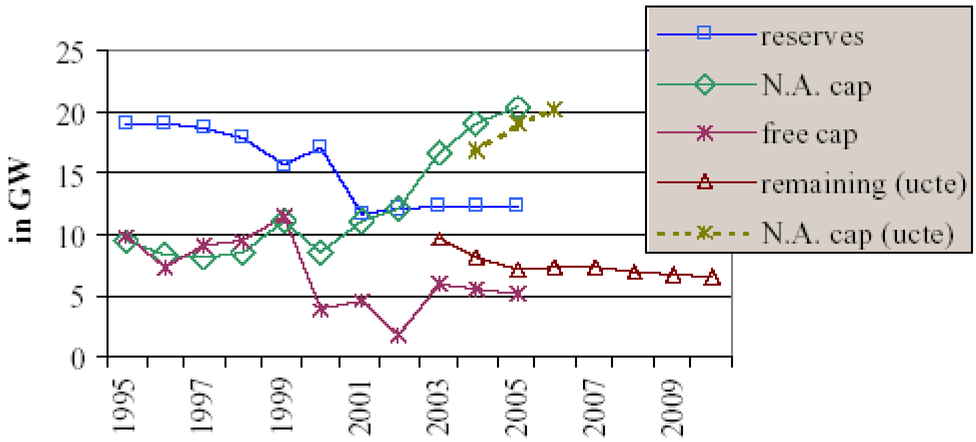
Some of this part is based on figures and information from "Regulation, Competition and Investment in the German Electricity Market: RegTP or REGTP)" (Brunekreeft and Tweleman, 2004).

There are two reasons to give attention to long-run capacity developments; security of supply and market power. Several occasions the last years have shown the costs, both political and industrial of power black-outs (California 2000/01 and Europe in the summer of 2003 for instance). Shortages in capacity also lead to possibilities for exploiting market power, because competitive pressure depends largely on the ratio between capacity and (peak) demand. This is a main factor in the German market where the four large suppliers control a huge part of the available capacity and also control the cross-border capacities. Another factor is that the short-run Cournot-competition[1] loses credibility when faced with excess capacity; the producers can avoid severe short-run price competition by reducing available capacity. For spot markets the capacity-to-demand ratio has already been recognized (CAISO, 2000, pp.50 ff); when there exist shortage in capacity, spot prices can rise quickly and to extreme levels. If this lasts, in the longer run these spot prices will serve as a signal to both incumbents and third parties to bring mothballed and new capacity into operation. For theoretical perspectives on this see Dixit and Pindyck (….).

The combination of the traditional model of cost-based regulation, incentives to invest in new capital and an obligation to guarantee a reasonable supply security, created severe excess generation capacity in Germany (summarized in figure 3.1.4)

Figure 3.1.4: Excess generation capacity

*Sources: Brunekreeft and Tweleman, Markewitz & Vögele (2001); VDN (*Leistungsbilanz*); UCTE 2003, 2004.*



In line with common industry practice, installed capacity has been spread over the following categories: maximum load, planned reserve capacity, non-available capacity (N.A. capacity) and, as the calculated residual, remaining (or free) capacity. The share of planned reserve capacity, which is primarily determined by reliability rules (like n-1), fell recently to approximately 11%, still relatively high. The planned

[1] For information on Cournot competition, see e.g. “Economy and the theory of games”, Vega-Redondo (2003)

reserve ratio fell as a result of a policy change: longer time between revisions and shortened duration of revisions, which implies that less capacity is under revision and thus less reserve capacity is required. There seems to be sufficient reserve capacity to cope with some unplanned scarcity. The increase in demand must be taken into consideration while analysing this. The ratio of 11 % is still above UCTE average. The category N.A. capacity covers both “unreliable” renewable (wind, approximately 90% of wind capacity is included in N.A. capacity) and mothballed capacity. Data for the UK collected by Ofgem (JESS, 2003, p. 13) examined the time taken to bring 3.7 GW mothballed capacity into operation: 1.3GW required 0-3 months, 0.3GW required 3-6 months, 1.0GW required 6-12 months and 1.1GW required 12-24 months. These numbers suggest that while some mothballed capacity can be returned to service reasonably quickly, as time goes by mothballed capacity deteriorates and takes longer to restore. A question on this matter is to which extent some of the nuclear capacity that should be phased out could serve as reserve capacity (mothballing), this is of course both an economic, a capacity, a technical and an environmental issue (more on nuclear later).

Wind capacity increasingly becomes a problem. This is due to the fact that increasing shares of wind power result in more dependence from wind and that wind power depends on the unreliable availability of wind. The category N.A. capacity for wind power contains capacity which is either available with some defined probability (according to experience or weather forecasts), or can be made available within a reasonable time (number of mills producing etc.), and so amounts to excess capacity.

A concern is the phasing out of 20 GW of nuclear assets over the next 20 years (discussed in the German Electricity Market chapter). Figure 3.1.4 (above) suggests that current installed capacity corrected for planned reserves would still serve peak load whilst allowing a significant part of the phasing out of nuclear power. The extent and speed of replacing the nuclear assets critically depends on the assessment of the availability of the non available capacity and investment in new capacity. UCTE forecast suggests that remaining capacity may be stable around 5 to 6 GW, which is around 5% of installed capacity. Two factors complicate the assessment. First, many power plants are relatively old. Second, whether the nuclear phase out actually takes place or will be reversed by a later government is highly uncertain.

3.1.2.2 Products, distribution and costs connected to change of supplier

The German border naturally limits the German power market, since Germany still doesn't have a common electricity exchange with any other European countries. Electricity is a homogenous commodity, which means no matter what company you chose; the same electricity quality is delivered your household/company. The factors determining the "quality" of the supplier is the security of delivery and the price they offer. In Germany the security of delivery is generally very good, so that should not be an issue. So it basically comes down to price.

Replacement of electricity from other energy products is also a possibility, especially when the electricity is used for heating purposes. The natural replacements here are oil and natural gas products, along with some renewables.

With a very short time horizon, electricity demand is inelastic to price changes. Only a small part of the consumption is sold through the spot exchange, and can adjust the running price development. This basically only goes for the part of the industry that can change between electricity through the market and from oil-fueled boilers on a very short notice. In addition some of the power intensive industry, that can close down on a short notice when prices increase.

Long- time prices are more elastic as the spot- price changes penetrates to the consumption prices. With a medium time frame, considering months or seasons the demand sensitivity is still relatively low. Some reduction in consumption can be done switching off lights, lower the heating in the household etc. In the longer term there will either be a need for more capacity or the consumption patterns need to be changed, by for instance lower industrial production or lowering the use in critical periods.

The price sensitivity of demand is important because it reflects what opportunities sellers has to rise prices without loosing to much volume, it also says something about the size of the welfare loss resulting from following such a strategy.

3.1.2.3 Vertical integration

The power industry in Germany was traditionally organised as integrated companies that were responsible for generation, transmission, and distribution. Before the deregulation each company was obliged to, and had the monopoly for power delivery within area of operations.

The deregulation changed this into a competitive market where each consumer in theory could buy his power from any generating company within Germany. This is however theoretical. As the four big companies in Germany still controls the grid in their areas, they attain information of the consumers in their areas changing supplier, and the "gentlemen's agreement" function so that the companies won't interfere with one-another. Since the market opening, 35 % of the large industrial users (annual consumption of at least 1 GWh) and only 6 % of small commercial participants have changed supplier. The remaining 65 % of the large industrials and approximately 25 – 50 % of the smaller have renegotiated with their existing supplier.

How did the companies choose to organise the monopoly and competition activities? A surplus from the monopoly business could be used to cross subsidise the competitive business areas. The monopoly activity is regulated to prevent the companies from earning excessive returns, and only earn sufficient income to cover the costs. An efficient regulation would lead to efficient tariffs for the monopolistic activities and in that way lead the focus over to the competitive areas, opening the possibilities for new third party access in the generation sector. According to this the accounting should be separate for the different activities, as it is in the Scandinavian market.

As long as the businesses are integrated however, it is very difficult to prevent that cost is divided in a way that leads to cross subsidising. The stronger the divide between the businesses, the easier it becomes to disclosure if cross subsidising exists.

3.1.2.4 Regulating the network

The German legislator relied on a negotiated third party access (NTPA) of network access within the sector and the ex-post control of possible abuse was left to the Cartel Office. The authorization given to the Cartel Office (Bundeskartellamt) was strengthened with an essential facilities doctrine. This stated that access to the networks should be given to third parties on non-discriminatory terms and against fair and reasonable charges. The sector associations negotiated a general framework concerning the network access conditions.

This association agreement (VV) was later revised to secure competitive incitements, and the initial VVI was in 1999 replaced by VVII. The latest revision gave the third version, VVII+.

3.1.2.4.1 Cost-based or price-based regulation?

Some of this part is based on figures and information from “Regulation, Competition and Investment in the German Electricity Market: RegTP or REGTP)” (Brunekreeft and Tweleman, 2004).

There has in the years since the market opening been minimal regulation of the network access. Negotiated TPA meant that the sector associations negotiated a general framework covering an outline for the access structure and methods to calculate the charges for access to the network. The level of the charges was left to the individual network operators to determine.

In April 2001, the Cartel Office examined the problems and prospects of applying competition law to the network charges. As a start it pointed out that control must be ex-post. Applying competition law and starting investigation requires suspicion of abuse of market power. Second, it developed (in some detail) methods to control in the cases where charges is found to be excessive, in particular methods based on cost-control and price benchmarking. The Cartel Office expressed a preference for the price benchmark, even though this obviously will give an information problem. The benchmark would compare a high-priced firm with a comparable low-priced firm, and since the low-priced does not abuse its market power, there is no reason to require the company to provide information. It is therefore believed that the Cartel Office was powerless and that the network charges were excessively high and a result of abuse of market power (for instance Monopolkommission, 2003; BMWA 2003; Canty, 2003).

Resulting from this report, the ESI came out with the latest revision of the association agreement, VVII+. This strengthened the concept of industrial self-regulation. First, VVII+ outlined the principles to calculate the level of the network charges and second, the VVII+ prescribed rules for transparent and harmonized publication of network charges (implicitly allowing the price benchmark). The later require that the distribution network operators publish network charges calculated for given demand profiles. For comparison, the network operators have been classified into groups controlling for the following parameters; east/west, consumer density and the share of overhead lines. If a high-priced network is not able to justify the level of the charges, the Cartel Office will investigate it. According to observation by Growitsch and Wein (2004) this reduced the spread in network charges.

The Energy Act of 2004 had the intention of applying the principles of VVII+ as the base for its regulation. The following principles will then be applied:

- depreciation is linear
- capital life duration has been specified in detail
- the underlying asset valuation method is written-down replacement value (for equity financed capital)
- the ratio of equity over total capital has been restricted to 40%

- the allowed real rate of return on equity has been set on 6.5%; this is post trade-tax, while pre corporate-income -tax. There is discussion to apply the principles of a CAPM approach (The corporate income tax is 25%, while the trade tax varies by region.)

These principles applied before the new Energy Act, but were not effectively enforced. Canty (2003) described the experiences of the Cartel Office and criticised the application of the principles on several counts, with the implication that the rules were simply not effective.

- Asset valuation relied on replacement values but depreciation did not. According to the rules, depreciation is determined at the start of the accounting year, while replacement value is determined at the end of the accounting year. Thus if the replacement value goes up and depreciation value is not (fully) adjusted both the cost including depreciation and the allowed return (at 6.5%) on equity is high. Either the Regulatory Asset Base (RAB) should be written down by the allowed depreciation (and incremented by investment) or depreciation should be calculated as the change in value of the original assets (excluding new investment).
- The allocation of an excessive fraction of common costs to the electricity network was also a problem, creating higher network costs, which can be recouped through higher charges. However, the nature of common costs implies that there is no simple cost-related method of allocation these costs. It is not clear how the common costs should be allocated to various parts of the business. If network demand were thought to be more inelastic than demand for the services supplied over the network, such an allocation could be justified on efficiency grounds, but this Ramsey argument would be hard to defend as the services are jointly supplied with the network. The fact that in many countries the network is under separate ownership from the competitive activities suggests that the extent of common costs in the vertically related electricity businesses (between the networks and the competitive businesses) is low.

- The practice that over-recovery of costs is not passed on to consumers (or otherwise recharged) was also discussed. The allowed rate of return is translated into an allowed revenue based on output estimated at the beginning of the accounting year, which in turn results in allowed prices. If realised output is higher, there will be an over-recovery and the rate of return will exceed what allowed. Current practice is to ignore this.

Since the VVII+ will serve as the base for the new regulation, the question arises how this specific practice will be adjusted. If there is no change and ex-post difference is not refunded to consumers, regulation is simply non-binding. If the excessive revenue is to be refunded there are two options available; the base for refunding may be the allowed rate of return, which means a rate-of-return regulation (this gives no incitements for cost efficiency, the company would get a predetermined rate of return no matter what the cost structure is) and, the base may be allowed revenues estimated as an approximate level of the existent practice. The latter is seen as the more practical approach and has similarities with price-cap regulation[2]. To summaries, it is considered that incentive-based regulation is good for efficiency, while cost-based is good for investments and therefore network adequacy.

3.1.2.4.2 Challenges confronting the Energy Regulator

There are several issues to be considered when appointing the responsibilities and objectives of the Energy Regulator. The first consideration is the objectives the Regulator seeks to achieve and the resources available to meet those objectives, and this gives the basis for how the role of the regulator will be. The objectives is (ERRA, 2004):

i) Increase competition among producers and among suppliers by reducing the importance of national borders as constraints on the electricity market

[2] Standard price cap regulation sets the initial price to cover costs including a reasonable rate of return and rolls this forward allowing for investments, depreciation and predicted productivity growth. The price formula is determined ex-ante and remains valid for the control period.

ii) Promote and encourage investments in the transmission network needed to fix critical bottlenecks and thereby lower electricity prices to consumers

iii) Promote and encourage investments in the transmission network needed to diversify electricity supply sources and thereby increase the national energy security of supply

iv) Manage transmission congestion efficiently, using market mechanism and price signals instead of rationing, first-come-first-serve or curtailment (see the congestions chapter for more about this)

v) Establish a system of inter-TSO payments so that each TSO will be compensated fairly for the transmission services it provides in a regional electricity market

vi) Implement a vision of a regional electricity market, based on the wording of agreements negotiated among political leaders at the highest level

vii) Ensure the stability of the high voltage network in a liberalized regional electricity market with independent suppliers and with many participants

If the Energy Regulator has only a minor role to play regarding objectives i) and ii), then the question of cross-border transmission capacity measurement and capacity allocation should be addressed by the TSO and by the Ministry responsible. However, it is considered the best solution to give the Regulator the whole responsibility for these issues. Considering how the regulation should be done by the Competition Authorities (CA), there are in addition to ex-post regulation, three possibilities for ex-ante regulation.

- The first comes from the Association Agreements, where the Bundeskartellamt has retained the right to block these private agreements. This has not yet been used, instead the CA has preferred to take the approach of using pressure and negotiations
- A second ex ante intervention possibility is that the CA can signal to firms the direction of future decisions in the area of curbing the abuse of market dominance, and publicly name firms whose rates may be the target of re-evaluation.
- The last ex ante intervention channel is the evaluation of an the possibility of stopping merger proposals.

3.1.2.5 Collusion

Germany chose to deregulate its electricity industry in 1998 with full opening, but no electricity regulator, as an opposition to most of the European countries. A regulator is seen to be the cornerstone of a competitive reform, because of natural monopolies of the network infrastructures, because of the externalities faced in operation of these networks, and because of the contractual hazards rooted in deep asset specificities. There are however analysis of the telecommunication (Wallsten 2001) that suggest that an independent regulator is not a necessary condition to the success of the reform. More about the regulator and the challenges for the regulator's role above.

Neither the rates set for access to transmission, nor the wholesale prices, nor the supply prices to the consumers, provide obvious evidence of abuse of market power by the transmitters, either by agreement or cartel (Glachant, Dubois, Perez, 2003). German rates for access to the grid are considerably lower than for example French and Spanish rates (and also UK), but only consumers in Germany pay for the use of the grid, making a price squeeze on transmission rates from the incumbent operators possible. After the market opening the prices charged large consumers dropped significantly (mean price fell by 25 %), and in January 2000 the prices were more than 10 % below the British price. But none of these facts can lead to a conclusion that the transmitters have engaged in abuse of position.

The credibility of a reform relates to the ability of its governance structure to solve regulatory problems between the government, the operators and stakeholders. This rests primarily on how stable the commitments are, which is given if three complementary mechanisms also exist: " (a) substantive restraints on the discretion of the regulator, (b) formal or informal constraints on changing the regulatory system, and (c) institutions that enforce the above (…) constraints" (Levy and Spiller, 1994). Stability of commitments is particularly crucial in infrastructure sectors. There are two main types of institutional environment; those characterized by many checks and balances on the one hand (for instance the US), and those that give discretionary powers to some political actors on the other (among others, UK). TO achieve credibility of regulations, several mechanisms had to be built in the regulatory governance structure. Firstly, few discretionary powers were given to the regulator, because of the use of licenses (Levy and Spiller 1994). Secondly, some checks and balances were included in the regulatory process (Spiller and Vogelsang 1997).

Concerning the first condition, the German electricity reform leaves few discretionary powers to the associations negotiating Association Agreements and the CA (in lack of a regulator to leave these powers to). The CA is limited in their decisions to the application of the competition law and also the CA's decisions can be challenged in court. The discretionary powers of the professional associations were limited by two mechanisms; the presence of the Federation of German Industries and large industrial consumers placed an ex ante and internal constraint on the formation of entirely anticompetitive agreements of electricity utilities, and two public institutions outside the agreements oversee the stability of the commitments that was made in them.

Concerning the second condition, it seems that the German electricity sector is vulnerable to legislative change. This is due to several occasions were legislation was left outside in critical decisions (in 1998, the legislator was unable to agree on a specific legislation, no regulator etc.). In the sense of Spiller et al, the reform of the German electricity sector was not totally credible as we can see, but there are some elements of what Spiller et al refers to as "weak powered credibility"[3].

3.1.3 Balancing

Fair network access conditions are crucial for the development of a competitive market. This refers to both the use of physical network access as well as for ancillary services such as the provision of balancing energy. In this part we expect that the reader has knowledge about the technical features of balancing and only discuss the efficiency of the German system of balancing.

[3] In an institutional environment that was problematic in terms of credibility, the regulator governance structure was built to overcome the credibility problems by appropriately using regulatory process.

3.1.3.1 The design of balancing markets and the cost of balancing

Some of this part is based on information from "Regulation, Competition and Investment in the German Electricity Market: RegTP or REGTP)" (Brunekreeft and Tweleman, 2004).

The balancing market is critical and with consequences for competition and new entry, because… Each of the four control areas has its own balancing market, managed by the network operators of RWE, E.On, EnBW and Vattenfall Europe. The current concerns are that the design gives opportunities for strategic manipulation and that rather high balancing costs are passed through into the network charges. The present system was imposed by the Cartel Office in 2001, as part of the remedies in merger cases and replaced unsatisfactory previous arrangements. In all areas there are pay-as-bid auctions; the long-term auction for capacity and short-term auction for energy are separate. Availability of balancing capacity is compensated by a capacity price, while in addition actual usage of the balancing capacity is compensated with an energy price. While the costs for the capacity payment is passed through to the network charges, the costs for (or revenue from) the energy prices is settled with a single balancing price. The E.On area is an exception, here this is calculated *ex post* as the weighted average of the auction bids (MGAP); in the E.On area, the balancing price corresponds to the marginal bid (*Mittlerer Gewichteter Arbeitspreis, MGAP*) Although this is the preferred model in well-functioning, liquid and competitive markets, it appears to be flawed in the German case. There appear to be two different problems currently:

- The first problem is that the system is vulnerable to strategic manipulation. The reason is strategic behaviour of the market parties. If for instance the MGAP is expected to be high relative to the day-ahead price (e.g. EEX), generators want to be long. Although the system reinforces itself, because the MGAP will decrease if all generators are long, the incentive for market parties to speculate on the balancing price may be undesirable as it destabilizes the system.
- The second problem is that market power is said to keep bids and prices relatively high. The issue is far from straightforward and needs more research

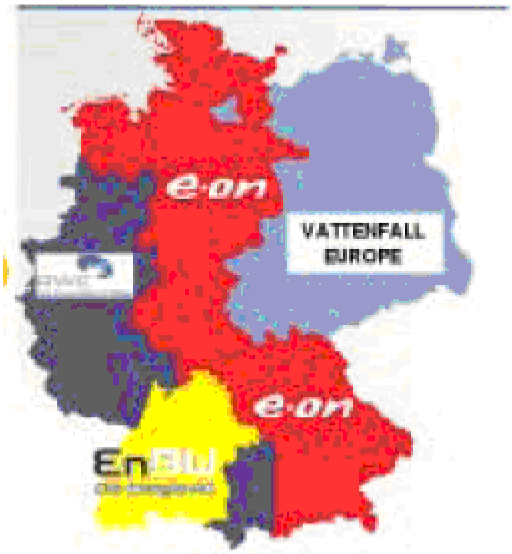
as it depends critically on details. We know that the integrated incumbents are dominant in their control areas, especially on the balancing markets. They can exercise market power if they like. However, the incentives are not clear. First, arbitrage with the spot market matters and can correct perverse incentives. This applies for the energy prices and not for capacity prices. It is interesting to note that the capacity price (for non primary reserve) in the RWE area stopped decreasing at the moment the E.On market was implemented in July 2002. This event reduced liquidity on the RWE market. Second, it is not straightforward how the integrated firms gain form exploiting market power. The generation business of the firm could profit from high prices, but the TSO department would have to pay for this. The energy prices are passed through to the MGAP, which is partly paid by third parties. The capacity prices are passed through into the network charges. The high balancing costs can so be used as a justification for higher network charges.

Illiquidity in the balancing markets (combined with and partly created by market power) can lead to significant differences between the day-ahead and balancing prices. The balancing price follows the day-ahead price roughly, but not perfectly. One contributory problem is that the control areas are separated. The basically technical requirements to participate for generators outside the control area are said to be high, which works to the advantage of the incumbent with generators predominantly inside the control area. Presumably, further (regulatory) steps towards integration of the control areas are required. Already the RWE control centre is the main control centre in Germany, so it might form a natural hub for an independent system operator (ISO).

3.1.3.2 Structure of the German balancing market

In Germany EnBW Transportnetze AG, E.ON Netz GmbH, RWE Transportnetz Strom GmbHNET and Vattenfall Europe Transmission GmbH are TSO and grid owner/operator. Of different reasons they established own, partly Internet- based RPM to procure the various types of balancing power by way of competitive tendering. The markets where gradually established in February 2001 (RWE), December 2001 (E.ON), August 2002 (EnBW) and September 2002 (VE). The areas served by these markets are equal to the areas served by the same TSO`s (figure 3.1.5).

Figure 3.1.5: TSO areas in Germany (Source: Vattenfall, 2004)



The balancing market is at the moment dominated by these power producers. One of the problems is the fact that only power producers can participate in the market place. On the contrary, in Scandinavia, also the industry can participate. This means higher degree of competition and thereby more efficient markets. The balancing period is 15 minutes in Germany (compared to 60 minutes in Norway). The charges are in theory market based. Nordic countries have supernational balancing, whereas Germany has regional. This is clearly a sub optimal solution considering the efficiency of the market. This negative feature is increased by the fact that each balancing area is dominated by one market player.

The general intransparency in the German power market also holds for the balancing market. There are also monopoly positions in the different areas, held by the sister companies of the area's grid company. One of the main price increase arguments brought forward by the Grid operators is the high balancing cost.

For plants covered by the EEG and the CHP law, balancing is not a relevant issue. They simply feed their output into the grid and the DNO has to deal with balancing. As for renewables, the DNO has to re-numerate the electricity at a fixed rate irrespective of the load profile. As a consequence the renewables operator does not have to bear the risk of intermittence. Whether or not the DNO can pass on balancing costs to the TNO, like he does with the energy he buys from renewables and CHP generators, is not entirely clear. A clear and transparent distribution of balancing costs would reduce the disincentives for DNOs to connect DG plants to their grid.

As for other DG plants, balancing does affect their operation. A properly functioning balancing market is developing only slowly. The same goes for reserve markets. Once again the weak regulatory framework has failed to remove barriers to competition. There have been repeated complaints that the providers of balancing energy, especially those connected to a TSO, abuse their market power and the Federal Cartel Office has been repeatedly called upon to investigate balancing prices.

While the TSOs claim that the increasing balancing costs are due to a significant increase of intermittent generation, mainly wind, there are also signs that balancing costs could be reduced if balancing markets became more competitive. Looking at DG as potential participants of balancing markets, there are two main impediments. First, plants need to offer at least 30MW or even 50MW, depending on the balancing zone, to be allowed to participate in the balancing market. This is relatively high but could be overcome by bundling several plants into one virtual balancing plant. This, however, has turned out to be difficult because each plant belongs to a balancing group and it is currently virtually impossible for plants to sell balancing power outside that balancing group. In autumn 2003, SFW and Saarenergie have organised the first virtual balancing plant in Germany, but so far they have only managed to include plant operators managing their own balancing group. As soon as a plant belongs to a balancing group managed by a third party, it cannot participate in the virtual balancing plant.

Solutions German balancing power:

- There should be one balancing zone only.
- The balancing prices must be regulated by REGTEP
- Less barriers to entry.
- More frequent auctions on the prim, sec
- Elbas at EEX

The balancing markets need to become more competitive and access for DG needs to be improved. Complete ownership unbundling would be necessary to separate balancing and provision of balancing energy, thereby removing the current incentive of integrated companies to maintain the demand for balancing energy at a high level and favour their own generating units to meet this demand. As complete unbundling will not be implemented in Germany, it is even more important that the balancing markets will be regulated by the new regulator to ensure competition on this small, but important market.

An important step to increase competition would be to set up one single balancing market for Germany, which is currently split in four balancing zones run by the 4 TSO. Setting up one common market could be done even with four separate TSOs. Once again, a strong regulator could certainly be the main driver behind such a development.

As for participation in balancing markets, the minimum capacity for plants should be reduced from the current 30-50MW. It is relatively difficult for small plants to participate in balancing markets on their own and transaction costs are high. Therefore improving the conditions for virtual balancing plants, so that plants can operate jointly to offer balancing services, would be even more important than reducing the capacity threshold. It is currently virtually impossible for plants belonging to a balancing group run by a third party to participate in a virtual power plant. Contracts for balancing groups would need to be amended to allow for such virtual plants and grid code would probably also need to revised.

3.1.3.3 REGTP

The German Energy Industry Act adopted in 2004 implemented the European reform package on the Internal Energy Market (Directive of 26 June 2003) where the previous option of Negotiated System Access has been omitted.

Some of this part is based on information from “Regulation, Competition and Investment in the German Electricity Market: RegTP or REGTP)” (Brunekreeft and Tweleman, 2004).

The decisive question is if the regulation will become efficient. There are reasons to be optimistic. Regulation has been placed in the hands of the Regulator for Telecommunications and Postal Services, which has rather more than five year’s experience and a reputation for toughness. It will have more authority to gather information, a key problem for the Cartel Office, and the regulator’s decisions will be effective until overruled by a court. This is not new in the Energy Act proposal as this shortcoming had been repaired in 2003 already. Finally, the regulator for energy has an initial budget for 60 employees, which, with over 800 network operators and ex-post cost-based control, may well be necessary. A newly created bureaucracy can be expected to be a new pressure group in the political process and will want to gain in importance. So, even if the first round of regulation is soft, an irreversible process may hopefully have been started. Opinions on the political independence of the REGTP differ. The fact that REGTP belongs to, but is at arm’s length from the Ministry of Economics is not the best guarantee for independence. On the other hand, and in contrast to telecommunications, the federal Ministry has no ownership interests in the energy sector.

Another issue is what can be gained if this regulation takes effect. First, network charges will fall, removing excessive profits, as a result of increased efficiency. Second, the companies will shift their focus from network operation to the competitive business of generation and retail, and the currently low margins in this market will rise. This again will give profit opportunities for new entry, and for instance CCGT will be a normally risky project in opposition to the former hazardous enterprise. This again helps the problem of low investment and security of supply. Lastly, as the threat of competition increases, the integrated firms will tend to use the network on discriminatory basis, increasing the problem of vertical integration. Thus, something needs to be done concerning this issue.

3.1.3.4 Strategic bidding

Many recent empirical studies of oligopoly competition include the analysis of bidding in auction markets. An assumption heavily used is that firms behave according to a particular strategic equilibrium model, this assumption gives the researcher the possibility to map firms' observed pricing or bidding decisions into their unobserved costs of production or their valuations for the auctioned object.

This analysis will not be done in this paper, but we leave it as a possibility for further studies to consider going through with this.

A precondition for testing strategic bidding, which can be done both for the balancing market and for cross-border auctions, is evidence of non-price-taking behaviour. In the electricity market, strategic behaviour can yield prices above marginal cost when balancing demand is positive and below marginal cost when demand is negative. An interesting aspect, which is observed for instance in Spain (Kuhn and Machado, 2004), is that market power can lead to prices that are too high or too low.

If demand is positive, a firm selling multiple units has incentives to increase the bid-price above marginal cost. This sacrifice of additional sales is to raise the revenue earned on inframarginal units. This is the standard oligopoly result that a firm acts a monopolist on residual demand. If total balancing demand is negative, the firms will markdown their bids below marginal costs. The logic for this is similar as for the positive demand[4].

3.1.4 Turbulence

After exploration of the exclusive possibilities of profit, the next question naturally is whether the companies will take advantage of these possibilities. Both exercising

[4] Suppose firm A has contract obligations to serve the customer 100 MW and has submitted a day-ahead schedule to generate 100 MW to cover that contract position. If the total demand is 10 MW lower then anticipated (but not for firm A's customer), there will be a balancing auction. Firm A still has a contract to satisfy, so it pays the balancing market price on the 10 MW short position. The firm exploits market power by bidding below marginal cost to sell itself into a short position but to lower the price at which it buys back the position.

monopoly and inefficient operations have some degree of irreversibility connected to them; increasing efficiency is time consuming and expensive, this also holds for regaining the trust of consumer that have been victims of monopolistic prices. As a consequence there is no given answer to this question. In addition use of market power can trigger changes in the governmental framework. Deciding whether to take advantage of the possibilities of profit is therefore dependent on what consequences this has for future opportunities.

A predictable and static environment makes the probability for future changes small, and therefore increases the willingness to take advantage of the possibilities present. On the other hand, an unpredictable and unstable environment increases the risk connected to inefficient risk and monopolistic behaviour, and can therefore work as a disciplining factor. However, this is not absolute. Sufficient uncertainty could lead to companies harvesting profits today, fearing that the opportunities will vanish in the future. An example of this occurred last December, when Vattenfall in anticipation of the coming regulative regime, significantly increased their network charges.

There are many sources of turbulence in the market conditions; international competition, new entries, customer behaviour, ownership, technological development, etc. The German power sector has without doubt gone through some major changes since the reforms started in 1998.

3.1.4.1 New entry

The post liberalization new entry, other than renewables, has been very modest. Around 200 new suppliers have entered the German market since the deregulation in 1998. There has also been an increase in market players, notably in sales and trading. The obvious candidate for entering the market is gas-fueled CCGT, where there has been four major projects. Two has already failed (OECD, 2003, p 20/21). Of the underlying reason for the failure, in addition to low wholesale electricity prices, was a change in tax law. Gas plants were exempted from paying mineral oil tax, but only for those on-stream before 2004, and for plant with fuel efficiency of over 57,5 %. This was changed in July, allowing for all plants with fuel efficiency over 57,5 % to be exempted for mineral oil tax. Further problems were caused by an increase in the gas prices and problems in gas supply contracts. There exist in Germany a gas spot market but liquidity is very low and dominated by Ruhrgas, and hence for CCGT plants, supply contracts with Ruhrgas is necessary. The situation worsened significantly by the merger between E.On and Ruhrgas mentioned earlier. The two remaining projects are Concord Power (at Lubmin) and a project by Trianel (near Aachen). The first is owned 50 % by EnBW and 25 % by E.On and is in that way not considered a third party. The second is still at fund-raising stage (January 2005).

Further new entry should be expected from renewable energies. The renewable energy act (EEG) combines a technology-dependent feed-in tariff and a take-off obligation on the network operators to whose network the renewable is connected. The feed-in charges, for which the costs are socialised over the network customers, are considered to be high and new renewable capacity, especially wind, is expanding significantly. This method is different from the methods considered in for example Norway, where production from renewables are taken into a certificate market (with obligations on the suppliers to use a percentage “green” energy) to secure a more fair pricing of this electricity. The promotion of renewables is expected to add 15 GW capacity in the next 5 years (Calculated by Brunekreeft and Twelemann using numbers from Pfaffenberger & Hille (2003, p. 5.9)). Currently, wind has a non-negligible output share of slightly below 5%, which is expected to grow to 9% in 2008. It is also necessary to develop other renewables in the coming years.

There are a number of controversies arising from the growth of wind power.

- The feed-in tariff for wind is still so high, according to industry observers, that new plant is built in highly unfavourable places.
- As wind is unreliable, the demand for reserve capacities increases, raising the issue of who is responsible for this, and who will pay for it.
- Another issue is the plans of offshore windfarms in the north, which will demand substantial reinforcement in the network. Should this cost be put on the network operators (which is usual) or is this cost so special it should be covered from other sources?

Another issue is the start of the European emission trading scheme (ETS) in 2005. The start of ETS reduces the necessity to subsidise wind and other renewables. Notwithstanding these arguments, there are no political signs that the system of feed-in tariffs might be changed in the near future.

New entry will be promoted by regulating network charges. As seen over, vertical integration and lack of regulation of network access charges created incentives for making profits from the network and not from the competitive business. Also, despite high concentration in generation and retail the margins were low, lowering the incentives for new entry by third parties. Regulation of network access charges is meant to change this. With the new system, vertically integrated firms should shift the emphasis on securing profits towards the competitive businesses and away from the networks, which will mean that concentration will matter and opportunities for new entries will increase. The new regulatory authorities therefore has a challenge of lowering the network charges at the same time as the margins increase so that the end-user prices (competitive stages) increase. This will offer new opportunities for entrants and secure and increase long-term competitiveness, which again can help securing supply.

3.1.4.2 ETS, NAP and new gas

Some of this part is based on figures and information from "Regulation, Competition and Investment in the German Electricity Market: RegTP or REGTP)" (Brunekreeft and Tweleman, 2004).

The generation mix in Germany relies heavily on coal and lignite (table 3.1.1); and which we can see from figure 3.1.6, the share of gas is still small. With the implementation of the European emission trading scheme (ETS) in January 2005, CCGT may be in a more favourable position because gas emits less CO_2 than coal. The ETS results from the EU Directive of October 2003 (EU Directive 2003/87/EC, establishing a scheme for greenhouse gas emission allowance trading; O.J. L 275/32, 25.10.2003), and is currently in the process of being incorporated into national law in various member states who are required to publish National Allocation Plans (NAP).

Table 3.1.1: Generation mix 2002 (in MW) (*Source: VDEW (2004)*)

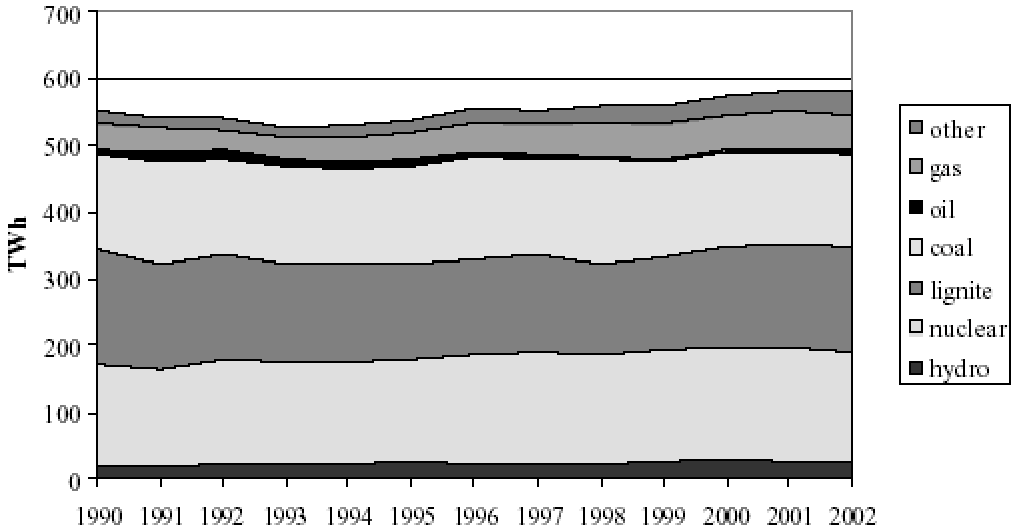
	capacity in MW	shares	Generation TWh	shares
Nuclear	21,283	23%	156	32%
Lignite	18,811	20%	143	29%
Coal	24,882	27%	114	23%
Gas	16,315	17%	36	7%
Hydro & Wind	12,471	13%	45	9%
Total	93,762	100%	494	100%

The ETS aims at introducing a system of tradable greenhouse gas emission rights, the most important of which is CO_2. The degree of detail in the Directive is low with many details left to the decision of member states. This will result in different and possibly conflicting rules. A key aspect arranged by the CEC is the prime method of allocation of CO_2 rights. Art. 10 of the Directive prescribes that for the period 2005 - 2007 at least 95% of all rights in each

member state, and for the period 2008 - 2012 at least 90% must be allocated free of charge. It is left for the member states to decide how the remaining rights are allocated (i.e. free of charge or auctioned). Futures on CO_2 rights are traded already.

Incorporation into German law and details of the allocation method are laid down in the National Allocation Plan for Germany (March 2004), for which the Ministry of Environment is responsible. With minor changes, the NAP passed parliament mid-July 2004 and is officially called *Zuteilungsgesetz* (ZuG). Caps for the sector "Energy and Industry" are 503 Mt CO_2/year for 2005-2007 and 495 Mt CO_2/year 2008-2012, considered by industry observers to be generous. The emission rights for existing plant will be allocated free of charge, based on historical value. This surely sacrifices some public revenue, but need not be inefficient in the manner that some plants cannot handle extra cost if to continue operation. This can be explained by a stranded-cost argument; the system will work out differently for different plants and thereby firms, and allocation free of charge will create profits overall and thereby soften these differences as probably all firms will gain. Problems rises with free of charge allocations to new plants. There are severe potential inefficiencies with new investments and the stranded cost argument is not plausible. But an argument for this is capacity and to promote new entries. There is still a difference between building new capacity and replacing old capacity (nuclear) with new when considering CO_2, but this discussion will not be taken.

Figure 3.1.6: Development of the generation mix in Germany (production)



Source: Pfaffenberger & Hille (2003, p. 3.1).

The ZuG distinguishes between genuinely new plant and replacement of decommissioned old plant for allocation of free of charge capacity in the latter. For a genuinely new plant, the free allocation relies on best available technology (BAT). The precise wording is: "The electricity benchmark is 750g carbon dioxide equivalent/kWh. This value is derived from the weighted average (...) of modern lignite, coal and gas -fired power plants." However, "the allowances will not exceed actual requirement but will be at least 365g carbon dioxide equivalent/kWh." (i.e. based on CCGT) (ZuG, 2004, p. 36). As the upper limit of 750g is the emission of an efficient coal plant, this clause protects coal, and this benchmark will also seem extremely generous to new gas. Therefore the benchmark is reduced to own emission values that correspond to the emission values of new gas. For replacement purposes there is a transfer rule so that rights allocated to the old plant can be carried over to the new plant. This rule avoids delaying replacement, but does not take into consideration the difference in technologies between the two. The fact that CO_2 rights are allocated free of charge to new plants will also mean that rights have to be kept in reserve. For now these have been set to 9 Mt/year, and if more is needed, additional rights must be provided by a government agency, which must buy these rights in the market. There are no possibilities for carrying allowances over from the first (2005 – 2007) to the second (2008 – 2012) period of the Kyoto agreement.

What are the implications for new gas entry into the market? The reason to only consider gas is that it is shown (Peek et. al, 2004) that with even moderate CO_2 prices, new investments to replace old will be gas. A CO_2 emission price increases variable costs and since gas emits less than coal and lignite, the increase is lower for gas than for coal. The key effect of the CO_2 emission price is that if the CO_2 price is high enough, gas will have lower variable costs than either coal or lignite (or both) and this will reverse the merit order. In effect, the load factor of gas will increase substantially (as it will decrease for coal and lignite), which increases output of gas plants *cet. par.*, in turn decreasing average fixed costs of gas plant and thus decreasing the entry price of new gas plant, at least relative to coal and lignite.

There are several factors that influence on the change in the entry price:

- Assuming the rights for existing plants are free
- If there is a cost on getting the rights, there is only an increase in the variable cost (which should be offset by an increase in the electricity price induced by the increase in the opportunity cost of emissions)
- If the allocation is free of charge
    - The ETS has an effect as the CO2 price increases variable costs as an opportunity cost
    - As the rights are freely allocated, they will be windfalls and reduce the fixed cost by the same amount

3.1.4.3 Customer stability

With the market opening, the possibility for switching supplier increased significantly, and since the market opening 35 % of the large industrial users (annual consumption of at least 1 GWh) and only 6 % of small commercial participants. The remaining 65 % of the large industrials and approximately 25 – 50 % of the smaller have renegotiated with their existing supplier. This numbers are not very high, and there has been very little change the last couple of years. In that way, the customer stability can be said to be very high and with the four big companies controlling their areas, it is expected to remain that way, at least until the European market will be one. In accordance, very little turbulence is created from this factor.

3.1.4.4 Ownership

The ownership structure of the largest companies in Germany's electricity sector has been very stable. Both E.On, RWE and EnBW is publicly owned companies noted on financial exchanges. In the case of Vattenfall, it is 100 % state owned by the Swedish state. EnBW is a bit different from the other to publicly owned companies, as Electricité de France (EdF) owns 34,5 % of the company.

3.1.4.5 Speed of innovation

Although you see some technological development in the power business, it cannot be categorised as particularly innovative. The power market in Germany doesn't, at least presently, have to fear competition from technological innovations.

3.1.4.6 Possibilities of cooperation on prices and understanding prices

Even though single companies not has the opportunity to use market power, groups of companies can through development of silent price agreements. The result is a market that appears as a cartel instead of a competitive market. The problem in Germany in this matter is that the four large companies are both electricity suppliers and grid operators in their area. This gives them the opportunity to control which company is supplying the customers in their grid area, and this information is used to maintain a balance that means the supplier and the grid company is one and the same. This can easily be seen from the customer structure in Germany, and in this manner the companies appear as a cartel.

3.2 Congestions

Officially there are no congestions within Germany restricting the flow and causing area prices. On the other hand we have very limited transmission to the neighbouring countries, restricting power flow that could help stabilising the prices. The right to control the intra border transmission on the German side of the border is governed by an auction system, where the auction is handled by the German company controlling the area of Germany that shares a border with a neighbouring country. This is not a very well functioning system. Also research done on the transmission line to Denmark shows that the flow goes in the "wrong direction" - from the high price area to the low price area.

3.2.1 Cross border management in Germany

3.2.1.1 Methods, evaluation and development

There are several basic methods of allocating of net transfer capacity, NTC; the maximum value of generation that can be wheeled through the interface between two systems, which does not lead to network constraints in either system, respecting technical uncertainties on future network conditions. Some of them referred to in the next chapter regarding border countries. To summarise, we shortly present the methods and their strengths/weaknesses in this chapter, which is based on ERRAs report from 2004.

1. Curtailment based on first come, first served

- TSOs establish a coordinated schedule for allocating NTC among bilateral agreements on a regular basis
- For each interface the TSOs would accept "contract flow" until capacity is reached

- This method is not effective if a power exchange is present in at least one of the countries involved, and is therefore not suited for the German market
- Since the four largest companies control the grid, this method will strengthen their market power. An independent TSO would maybe help here, but this would still not help significantly.

2. Curtailment based on ranking according to power market bids

- Interface between country A where a power exchange is operating and country B with no exchange
- For sales from B, the highest priority is for the lower bid price and for purchases from B, the highest priority is for the highest price
- With more and more exchanges popping up and a vision of a pan-European market, this method is at best temporarily

3. Curtailment based on pro rata rationing

- TSOs establish a coordinated schedule for allocating NTC among bilateral agreements on a regular basis
- If the net requirement for transfer capacity in direction A-B is 125 % of NTC, every request will be cut by one-fifth
- Prices are ignored
- As a consequence, this method is inefficient from a pricing standpoint, but it can help against market power. There is of course better ways to prevent market power from being used, so this method is highly unrecommendable.

4. Curtailment based on relative contribution to physical power flow

- TSOs establish a coordinated schedule for allocating NTC among bilateral agreements on a regular basis
- The highest priority is given to the bilateral transaction with the highest ratio of physical flow in MWh to contract volumes in MWh
- The lowest priority is given to the bilateral transaction with the lowest ratio of physical flow in MWh to contract volumes in MWh

- Prices are again simply ignored
- This method is inefficient from a pricing standpoint

5. Auctioning method

- The TSOs on both sides of the border agree to conduct an auction on a regular basis
- Each market participant offers a price for the use of the transfer capacity in one of the directions
- This gives the TSOs information to find out which is the constrained direction, and can then give the highest priority to the highest bid
- Bids in the constrained direction is accepted until NTC is fully committed
- Often used method, gives the opportunity to control the auction and is in that way surely a driver for use of market power

6. Market splitting

- TSOs establish a power exchange that covers the entire region including the national borders or interfaces that may be congested
- The region is divided into "price areas", so that each area can have its own pool price
- Available Transfer Capacity (ATC) is given to the power exchange
- If there is no congestions, the pool prices (spot price) are the same in all price areas
- In case of congestions, the high price area will be the deficit side (in terms of supply) and the low price are will be the surplus side.
- This method is successfully implemented by Nord Pool in Sweden-Norway-Finland-Denmark

7. Redispatching

- TSOs establish a coordinated schedule for allocating NTC among bilateral agreements on a regular basis

- TSOs would issue dispatch instructions to power stations to relieve congestions, so that there would be "uncongested" dispatch instead of "contract flow" dispatch
- High-cost power stations located in uncongested areas would be asked to generate additional electricity
- The power stations would insist on receiving compensations for this change in the dispatch order and the TSOs therefore need to raise the transmission tariffs to consumers
- The cost of congestion is hidden in the transmission tariff
- Used when there is a regional power exchange as well as bilateral agreements
- Better than market splitting on intradaily basis, because of simplicity
- Can also be used in a region with two or more power exchanges, plus bilateral agreements
- This method is inefficient in the way that it does not at every time produce the cheapest energy, but the marginal cost can raise by more than expected at several times if there are congestions

8. Cross-border coordinated redispatching

- More sophisticated version of redispatching
- All of the TSOs in the region cooperate to find the "uncongested" dispatch order that minimizes the cost of this operation over the whole region
- The TSOs would compensate each other, or else generators in each others' territory
- This will surely function best when there is close cooperation among the TSOs

The European Commission, ETSO (The European Transmission System Operators Association) and CEER (Council of European Energy Regulators) favour the two methods, Auctioning and Market splitting, but there are also some advanced methods that should be considered including Locational marginal pricing and Coordinated auctions which both are in use.

9. Locational marginal pricing

- Require an energy exchange over a large region, including two or more TSOs, so that the exchange arranges spot market transactions across the interface between the TSOs
- The entire region is divided into nodes (small geographic areas) so that each node has its own market-clearing price in each hour
- In case of congestions, there will be "high-priced" and "low-priced" nodes
- When there is no congestions, the market-clearing price will be the same in all nodes
- One of the important points here is that there is no attempt to achieve a uniform tariff over the region covered by the exchange
- This method is a very effective one of managing transmission congestions and is implemented in PJM and other exchanges in the US, and also in Norway

10. Coordinated auctions

- Require to give one auction operator the responsibility for managing all the interfaces in a large geographic area, such that all bids (both import and export requests for all of the national borders) are received simultaneously
- The operator must find a solution that avoids the need for any buyer or seller to participate in more than one auction, to implement a bilateral transaction within the geographic area
- The market clearing prices are determined for all of the borders in one auction
- Implemented in a modest scale in the Belgium/Netherlands/Germany auction and also in the Germany/Poland/Czech Republic auction
- Never implemented in large scale

11. Area-to-area surcharges + coordinated redispatching

- The TSOs publish weekly or monthly tariffs that include area-to-area surcharges which are applied to groups of transactions between any two areas subject to transmission congestions
- The region should be divided in areas such that there is expected to be very little congestions within each area

- The TSOs would set prices that are intended to simulate the results of a coordinated auction, example: In case of a congestion between area A and area B, and the result of an auction would be a cross-border fee of about 2 EUR/MWh, the TSOs would apply a 2 EUR/MWh surcharge for any transaction between a producer/exporter in A and a customer/importer in B
- If the estimates are "good", the cost of redispatching will be minimised
- This method is not pursued by ETSO or CEER because the TSOs would be given an opportunity to set "incorrect" area-to-area surcharges without regard to market conditions

12. Market coupling

- As an alternative to daily auctions
- Example Denmark-Germany
    - During 25 % of the hours the power flow is in the wrong direction
    - Loss on both Germany and Denmark
- Goal:
    - Create better functioning power markets and more reliable spot prices
    - All physical capacity is always used with the power flowing in the right direction
- Create a Market Coupling Auction Office (MCAO), which gets capacity information from the two countries TSOs and market information from the two countries power exchanges
- New company, TradeCo (ex), balance responsible for the market coupling power, and responsible for the power traded at the exchanges due to the market coupling. Has the same obligations towards TSOs as any other market player
- TradeCo will submit his bids/offers later than the other players (after MCAO has calculated the cross-border power flow. TradeCos trading is based on the price differences between the two exchanges, and the company will only trade the amounts calculated by the MCAO

3.2.1.2 Border countries

France

The allocation of capacity only concerns the German side of the cross-border interconnections from the control areas of EnBW and RWE to France. Should capacity rights be required for the transmission of electricity via such interconnections congested on the French side, these will have to be purchased by the respective market player according to the terms and connections applicable in France. The tradable transfer capacity is referred to as NTC, Net Transfer Capacity, which is the available transfer capacity between Germany and France less safety margins which must be reserved for transmission system operation within the European interconnected system.

Auction means the allocation of transmission capacity for the following day, or for the following days in the case of weekends and/or holidays. Within an auction, it is possible that different prices, which an auction participant is willing to pay, and different transmission capacities are communicated for particular hours. It is RWE Transportnetz Strom GmbH that coordinates the joint auction for the Franco-German interconnector on behalf of the TSOs, RWE and EnBW. The auction participants are balancing group managers participating in the auction. A bid is considered to be the time series over 24 hours, consisting of the transmission capacity per hour (in MW – 500 MW max), for which an auction participant bids plus the respective (in euro/MW) per hour. The auction participant submits the bids in a bid file.

Participants: To participate a balancing agreement with the respective transmission system operator (EnBW and/or RWE) must exist. This is necessary because schedules must be submitted from the control area in which the transmission capacity rights were acquired. Prior to the initial participation in an auction, the participant need to contact the auction coordinator to settle administrative issues and for admission purposes. RWE or EnBW can exclude the participants if there are grounds to fear that the participants will fail to meet their payment obligations or will be late with their payments (amongst these grounds are repeatedly avoiding payment, remainders do not help, illiquidity etc.).

Elements of the auction

- Publication by 8 pm
- Deadline 8.30 am, for submitting and cancellation
- Max 10 bids, max 500 MW
- Three cases:
    - 1. bids<capacity: no auction price
    - 2. bids=capacity: auction price=lowest bid
    - 3. bids>capacity: auction price=marginal bid
- Results available at 10 am

While Germany in 2003 imported 20,3 TWh from France, the export was only 0,2 TWh. The transmission system in France is controlled by EdF (Electricitè de France), which controls 45,81 % of EnBW.

Poland and Czech Republic

Cross- border capacity auctions Czech Republic / Germany

The request for capacity at the transmission border between E.ON Netz and CEPS is much higher than the free capacity (E.ON hjemmeside). Capacity auctions are used as a mean to allocate the available capacity. Since 2003 the auctions are realised in co-operation of E.ON Netz and CEPS, and reservations are valid for the entire border crossing. Currently three different auctions are in use: Annual, Monthly and daily auctions. For the monthly and yearly auction the procedures are similar: the auction office announces the available transmission capacity in each direction, a deadline is set and then the bidding begins. In the following part we will elaborate on the special features of the different auctions.

Annual auctions

In 2005 and … the annual auction was organised by the office at E.ON Netz. Two separate auctions are held, one for each directions. The participants of the auctions submit bids until the deadline, which they are ready to pay independently of the transmission fees. With delievery of a bid the participant commits himself to pay the determined auction price for the reserved transmission capacity independently of real using. (se vedlegg for mer info)

If the amount of all requested capacity is less than the transmission capacity available for reservation, the congestion management fee is equal to zero, i.e. each auction capacity participant receives the demanded capacity free of charge. If the sum of requested capacity equals the available capacity, the congestion fee is equal to the lowest bid within the offered capacity. If the sum of all bids exceeds the available capacity, the congestion management fee is determined by the reduced bid.

To use the reserved capacity a valid balancing agreement with E.ON and a valid transmission contract with CEPS for cross-border transmission and at the same time meeting the conditions and financial guarantees resulting from this agreement are necessary. Reservations from the annual auction can be transferred only for whole calendar week(s) to other market participants by the auction participants with reservations.

Monthly auctions

Same procedure

Daily auctions

Each market participant who wants to use its reserved annual or monthly capacity must, in order to do this, submit to E.ON Netz at 8:30 on the Czech border binding schedules that can no longer be changed. If the total of these binding schedules is less than the free capacities for the following day, this difference is offered again in a daily auction.

Table 3.2.1: Auction between Germany and the Czech Republic

	Auction 1: CZ->D			Auction 2: D->CZ		
	Offered capacity [MW]	Reserved capacity [MW]	Price [EUR/MW]	Offered capacity [MW]	Reserved capacity [MW]	Price [EUR/MW]
Annual auction	750	750	36.298,12	450	450	132,00
January	250	250	4.105,00	400	255	0,00
February	200	200	4.292,00	200	200	1,21
March	150	150	8.675,00	130	130	4,45
April	150	150	7.219,00	100	100	4,45
May	150	150	7.099,00	130	130	0,83
June	200	200	6.415,00	90	90	11,11
July	250	250	4.037,00	50	50	158,00
August	200	200	4.356,00	250	249	0,00
September	150	150	4.406,00	270	269	0,00
October	150	150	5.397,00	290	289	0,00
November	150	150	4.681,00	250	249	0,00
December	100	100	5.469,00	150	150	1,01

Cross- border capacity auctions Czech Republic / Germany /Poland

For the border area where Vattenfall is the grid operator, Vattenfall has agreed principles of the coordinated cross border transmission capacities allocation procedure with CEPS (Czech Republic) and PSE-Operator (Poland). This management mechanism is designed as explicit cross border capacity auction to be valid in 2005. The method will be market-based and aims at maximising the capacity while ensuring security and reliability standards. Market participants will bid for commercial profiles between the two TSO operating the neighbouring system. Auctions will be held for yearly, monthly and daily periods. The capacity will be set taking into considerations bid prices, technical availability and reserves necessary. Auctions will be administrated by an Auction Office (AO) which represents the three TSO involved, and will in 2005 be located at CEPS in Prague. Market participants have to register at the Auction Office to take part. Doing this, they accept auction rules.

Some of the main points of using an auction system:

- Network limits are interdependent and affect several border profiles
- Market based methods allows allocation of limited capacity according to the value placed by market participants
- Coordination of; capacity limits assessment, common allocation procedure, common administration of physical transmission rights

Coordinated auctions benefits:

- Common transmission capacities allocation rules in the region
- Maximization of available transmission capacities with secure operation of each concerned transmission system
- Guarantee of transmission capacities allocated in yearly, monthly and daily auctions
- Short term capacity transfer for daily or hourly periods

The auction:

- Bids are submitted to the AO; monthly and yearly by mail, daily by software

- Bids should content identification, cross border capacities to be reserved, offered price
- min 1 MW, max 50 MW. Max 20 bids.

There are three cases as for the Franco-German border for determination of the auction price and the same pricing rules counts (see over). There are some extra rules when it comes to marginal bids. For the daily auctions the “first-come-first-serve” principle is used and the marginal bid can be cut (partially accepted) if marked as divisible in auction form. For the yearly and monthly the marginal bids exceeding capacity are removed and the remaining capacity is allocated in subsequent auctions (year to month, month to day).

Table 3.2.2: Auction between Germany and the Czech Republic/Poland

Auctions results year 2005:

Commercial Profile Direction	*Promise of capacity (MW)*	*Price (EUR/MW)*
VE-T – CEPS	*282*	*0,00*
CEPS – VE-T	*320*	*53 260,80*
VE-T – PSE-O	*0*	*8 935,20*
PSE-O – VE-T	*480*	*101 186,63*

The most important experiences from Poland:

- The auctions Poland > Germany often tend to be quite expensive
- The forward market has developed the last year and the liquidity is good up to the front month
- An expensive and user-unfriendly nomination software
- The PolPX is expensive for traders
- Big scheduling risk (in case of a mistake, the whole schedule is rejected)

The most important experiences from the Czech Republic:

- Daily capacity normally fairly priced
- Low liquidity

There are plans to expand this auction system so that also E.On, Seps (Slovak Republic), APG and Mavir (Hungary) will take part.

The Netherlands

Capacity allocation

Capacity allocation on the Dutch-German border (and the Belgian-Dutch border) takes place under an auction organized by the TSO Auction Office, subsidiary of Dutch TSO, TenneT. There are two independently auctioned interconnectors connecting TenneT with German TSOs, E.On and RWE. Auction takes place at three time intervals, yearly, monthly and daily. The capacity is auctioned in both directions separately. Capacity rights are non-binding options which can be nominated by the holder. If the demand for capacity is less than the available, its price is zero. Otherwise the price of the last accepted bid sets the price. Year and Month capacity can be sold back and is then auctioned on the Month/Day auction and its revenue benefits the seller. If Year or Month capacity is not nominated till the day of execution, it is automatically transferred to the Day auction and the holder of the rights gets no compensation ("use-it-or-loose-it"). The maximum bid is for 400 MW.

Figure 3.2.3: Auction between Germany and the Netherlands

Year	From	To	Yearly Capacity [MW]	Price [EUR/MWH]
2005	RWE	TenneT	356	51 700,00
	TenneT	RWE	356	603,35
	E.On	TenneT	216	51 868,01
	TenneT	E.On	216	603,35
2004	RWE	TenneT	356	54 021,75
	TenneT	RWE	356	878,40
	E.On	TenneT	216	52 704,00
	TenneT	E.On	216	963,60
2003	RWE	TenneT	356	59 130,00
	TenneT	RWE	356	920,00
	E.On	TenneT	216	60 444,12

	TenneT	E.On	216	878,00
2002	RWE	TenneT	356	155 490,00
	TenneT	RWE	356	1 319,00
	E.On	TenneT	216	160 476,00
	TenneT	E.On	216	876,00
2001	RWE	TenneT	356	95 484,00
	TenneT	RWE	356	307,00
	E.On	TenneT	216	92 203,36
	TenneT	E.On	216	750,46

Outcome of capacity auctioning:
The auction does not allow netting, and it follows that the acquired capacity is an option, not an obligation. As a consequence, two identical transactions in opposite directions can use a serious amount of Available Transfer Capacity (ATC), but in fact there will be no physical flow. A great part of ATC is bought up by traders and arbitrageurs, who will only nominate if they expect a satisfactory price evolution. Depending on their missions and goals, some market players prefer to risk paying more for the capacity rights and be sure of having it (price risk) than to bid low and maybe not get it (volume risk). This is observable for the Dutch-German border in 2003, with high fluctuations of daily capacity price and more stable and cheaper long-term capacity prices.

Austria and Switzerland

The connections Switzerland-Austria, Switzerland-Germany and Austria-Germany are not under normal network conditions subject to declarations of bottlenecks. It would be desirable for the TSOs either side of each border to agree standby market mechanisms in case circumstances change. As the market function today, this gives a possibility for market control for the grid companies controlling the borders, which in Germany is E.On, RWE and EnBW, there is unfairness and inefficiency of the methodologies used (“first-come-first-served”, “pro-rata-reduction”). The failures to progress market based mechanisms seem to be attributable to a mixture of well defended vested interests with differences of view about the likely fairness and efficiency of allocations resulting from any auction.

Between Germany and Austria real trading takes place only in long-term and day-ahead contracts, and today only German and Austrian day-ahead prices are comparable based on publicly available price information. The access to German market is identical to Germany-based companies.

The cross-border capacity Germany-Austria and Germany-Switzerland does factually not restrict day-ahead trading today. The capacity price for day-ahead cross-border capacity Germany-Austria and Germany-Switzerland is factually zero.

Denmark

The exchange between Germany and Denmark is divided in two areas, where one is E.On Netz – Eltra and the other is Vattenfall Europe – Elkraft. The system used for allocation of capacity here is auctioning. The principles in the areas are the same, and as an example we use the E.On Netz – Eltra link.

The request for capacity at the transmission border between E.On Netz and Eltra is much higher than the free capacity. For a transparent procedure for the allocation of this transmission capacity without discriminatory auctioning is used. The auction in 2005 is organized by an auction office at E.On Netz. The allocation of free capacities takes place related to the direction. The total capacity between Germany and Denmark West (DK1, Eltra) is 1200 MW, and the transmission capacity offered at the auction is 350 MW. The total capacity between Denmark West and Germany is also 1200 MW, and the transmission capacity offered at the auction is 200 MW. For the capacity Germany – Denmark East (Elkraft) the total capacities are 550 MW both ways.

The auction procedure is much the same as other auctions described earlier in this section.

Summary

As we can see, Germany uses auctioning methods for allocation of capacity on the following borders:

- Denmark
- Czech Republic
- Poland
- France
- The Netherlands

Other allocation methods are used on the following borders:

- Switzerland
- Austria

The import/export is shown in table 3.2.4:

Figure 3.2.4: Export/imports German border (Source: VDN: www.vdn-berlin.de)

Electricity imports and exports from/to Germany in 2003/2004
physical flow in billion kWh

	imports 2004	imports 2003	exports 2004	exports 2003
Austria	4,4	3,3	8,9	9,9
Switzerland	2,8	3,1	11,8	13,2
France	15,5	20,2	0,4	0,2
Luxembourg	0,8	0,8	4,9	5
Netherlands	0,6	0,6	17,3	15
Denmark	5,3	4	3,4	5,4
Czech Republic	13,1	12,8	0,1	0,1
Poland	0,4	0,3	3,2	2,8
Sweden	1,3	0,6	1,5	2,2
Total	44,2	45,7	51,5	53,8

3.2.1.3 Steps to increase competition

To increase competition, it is an option to reduce the importance of national borders as constraints. Another issue is to fix critical and potential critical bottlenecks by incitements for investments in capacity. There are several factors that can be changed to achieve this (ERRA, 2004):

- Identification of the region which NTC needs to be measured and allocated, and a more specific identification of the countries involved
- Definition of the voltage levels of the lines and transformers that are part of the network for transmission, and identification of the TSOs and TAOs involved. Finding of the dispatch centers operated by the TSOs.
- Collect the interconnection agreements and import-export contracts that could be used to measure Notified Transmission Flow (NTF), and use this with the TSOs values of NTC to calculate the Available Transfer Capacity (ATC) on a day-ahead basis.
- Find a method of allocating ATC and implement this method
- Restrict the amount of NTF held by one market participant, if that participant is a monopolist, or influence market prices by restricting other participants' access to cross-border capacity.
- Ensure independence of the TSOs and TAOs from any company or entity involved in generation and supply
- Select the "worst-case scenarios" used by TSOs for planning purposes and to implement the reliability standards for the transmission network (lower-than-expected rainfall, higher-than-expected load growth etc.)
- Forecast annual energy requirements, peak load and resources available to meet them, under different scenarios over a longer time period (ten years).
- Identify critical bottlenecks and propose investment projects that would alleviate or remove these bottlenecks
- Set transmission fees at a level that will enable the TSOs to raise capital and make investments in projects needed to remove critical bottlenecks

Special for Germany, there are some hurdles for cross-border market optimisation today:

- Difference in schedule register mechanisms, timing and format on both sides of the border (e.g 15-minute intervals in Germany, 1-hour intervals across the border)

- Power exchanges uses a range of different trading and clearing systems
- Cross-border “tariff” of 0.50 EUR/MWh
- Allocation of grid constraint capacity through explicit auctions
    - Explicit auctions are not synchronised with respect to: timing, formats, regulations
    - Double uncertainty for constraint capacity and market conditions

To abolish these hurdles, a method can be to harmonise over countries:

- Schedule registration with TSOs:
  Harmonisation of mechanisms, timing and format for schedule registration

- Allocation of grid capacity
    - Harmonisation of mechanisms for capacity allocations:
      Today e.g implicit auctions in Scandinavia, explicit auctions in Germany
    - Harmonisation of mechanisms for explicit capacity allocations
      Timing, formats, regulations, admission, tools

- Power exchanges
  Harmonisation of rules and regulations, admission processes, trading and clearing systems among the different European power exchanges

3.2.2 Exploiting market power in the low price area

This is discussed earlier in the chapter of strategic bidding under “Sources of profability”.

3.2.3 Price differences day-night

For price information, see the analysis later in this paper.

3.3 Company relations and market concentration

In the power sector there are an unusual amount of close relations between companies including; cross- ownership, commonly owned generating facilities and other forms of cooperation. In this chapter we analyse the implications such ownership relations have on the competition in the German power market.

Many companies in Germany have common or crossing ownership interests. In some cases because several companies have a common owner; organised in a concern or laid under a holding company. In other cases one owner has a minor ownership in more than one company; diversified ownership. A third type of crossing ownership exist if power companies has positions in each other's companies, this is called cross-ownership.

Crossing or common ownership can inflict the companies' incitements for competition. Also, ownership relations give an opportunity to coordinate decision-making, for example concerning market strategy, investments, and behaviour towards customers, competitors and governments. The degree of coordination is dependent both the type and size of ownership relations. In some cases the relations are so strong that the companies has to be seen as one entity. On the other hand, when a company only possesses a minority position in another, the relations can be sufficiently weak to consider the companies as independent entities.

3.3.1 The extent and character of the company relations

The four major companies own and control a number of smaller companies and their structure and some of their owner interests are summarised in Appendix xx.xx. As we can see there is not many co-owned companies in Germany. A more important fact is that the major companies own smaller companies in different areas of Germany, according to where they operate as TSOs.

This implicates that the company relations are very limited, and in stead the cooperation is based on a splitting of the market.

Table 3.3.1 The four major companies in Germany

	RWE AG	E.On AG	EnBW AG	Vattenfall Europe
Country	Germany	Germany	Germany	Sweden
Turnover [billion EURO] (Spiegel 33/2004)	12,2	12,9	7,4	8,3
Energy delivered [TWh] (Spiegel 33/2004)	102,5	85,2	64	31,6
Change in financial result Q1 2003 - Q1 2004 (Spiegel 33/2004)	12,40 %	13,40 %	27,30 %	10 %
Noted	Yes	Yes	Yes (EdFI: 34,5 %)	No 100 % state owned
Customers (millions)	25 in Europe (6,2 direct consumers)	12,6 Electricity 3,5 Gas 13,2 Water	4,5	5,7
Other (than el) products	Gas, water	Gas, water, garbage removal	Gas, water, garbage removal	Heat and telecom
Main markets	Germany, UK, USA, Scandinavia	Germany, UK, USA	Germany	Scandinavia, Germany, Poland

3.3.2 Competitive implications

The establishment of relations between power companies could be done by different motives. In some cases it promotes efficiency and has positive implications both for the corporate economy and for the society economy. Some relations are also promoting competitiveness. In other cases, especially if the companies involved coordinates behaviour, and thereby strengthen their possibilities of exercising market power, such relations would undermine competition and lead to society economic losses.

The implications for the German market is that the customers freedom of changing supplier is limited as the different participants (the major) only operates in their market, and is not interested in entering the other areas of Germany to compete.

3.3.2.1 Incitements for competition

This is discussed earlier in the competition analysis, where we look upon the opportunities for regulating the market in such a way that the incitements for competition increases. Some of the factors discussed are the possibility for one TSO, and one auctioning system, along with a common European market, which will reduce the market power of the major four participants in the German market.

3.3.2.2 Ownership and control

The German law is such that a larger company has rights to membership in the board and to influence on the production volumes etc if they own 25 % of the company. As we see from the tables in Appendix xx.xx, the four major companies have controlling amounts of share in a number of companies, concentrated in the area they operate as TSO. This adds to the already significant problem of concentration and segmentation in the German electricity market, as mentioned.

3.3.2.3 Summary

In competition analysis it is usual to measure the competition in the market by the "degree of concentration". A market is more concentrated the less independent market players that participate in the market, and the larger the power of the dominant participants is.

We do not analyze the market concentration by some measuring instrument as the Hirschman-Herfindal index as it is quite clear that the concentration problem exists in the German market. For more about this index, see "Kraft og Makt".

Market concentration is the important issue in the German market. There are four market participants that control 81 % of the market (see chapter 2) and this is a very high number, as also the EU points out (see chapter 3.1). The German market is divided in four areas, one for each of the TSOs. The concentration is visible both in the way the major participants invest in smaller companies and in the customer relations in each area.

3.4 Ownership and competition

There is a strong focus on the power sector from the politicians and the government. This is maybe not a very wanted situation. However, there have been several changes and also the market opening gave more attention to the power sector. In the later period, there has been the issue of a regulator and also the Kyoto obligations have influenced on this sector.

Other issues of constant interest are how the companies are owned, and the competition rules associated with this.

3.4.1 Owner structure

The ownership of the four major companies is as earlier mentioned different. The table 3.4.1 – 3.4.2 show the owner structure of E.On and EnBW. Vattenfall is 100 % owned by the Swedish state, and the statistics for RWE shows that the biggest amount owned in this company is 0,411 % and the three largest owners have some 1,2 % and are Investment and Insurance companies.

Table 3.4.1 Owner structure of E.On Group

Owner structure:	
Geographic:	
Domestic shareholders	54,60 %
Foreign	45,40 %
"- Continental Europe (except Germany)	12,44 %

Corporate:	
Insurances, banks, asset management and investment comp.	58,60 %
Treasury	4,75 %
State of Bavaria	4,96 %
ADRs	2,14 %
Others	29,46 %
Main shareholders:	
Freistaat Bayern	4,90 %
Allianz AG	3,60 %

Table 3.4.1 Owner structure of EnBW AG

Ownerstructure:	
Shareholders:	
Electricité de France International (EdFI)	34,50 %
Zweckverband Oberschwäbische Elektrisitätswerke (OEW)	34,50 %
Deutsche Bank	5,86 %
HSBC Trinkaus & Burkhardt	5,86 %
Badischer Elektrizitätsverband	3,44 %
Gemeindeelektizitätsverband Schwarzwald-Donau	1,58 %
Streubesitz	1,49 %
Sonstige	1,17 %
Own shares	11,60 %

3.4.2 National energy policy targets

The German energy policy is mainly driven by three major targets (Bauknecht, Timpe and Leprich, 2004):

- Security of supply
- Environmental compatibility
- Economic viability

In the course of adopting the Kyoto protocol, the EU has agreed to a common agreement for the countries in the union, which requires Germany to reduce its emissions of greenhouse gases by 21 % until the first commitment period (2008 – 2012) compared to 1990 levels. The German government had announced earlier a voluntary target to reduce CO_2 emissions by 25% until 2005, which will most likely not be met.

There are two energy policy targets, which relate more directly to the development of distributed generation (DG). In the field of renewables, Germany has adopted the target of doubling the share of renewable energy sources in electricity generation. This means an increase from 6,25% in 2000 to 12,5% until 2010. The draft revision of the Renewable Energy Law, which has been agreed within the government, also foresees a long-term target of 20% until 2020. Because a significant part of this target will be fulfilled by offshore wind power and large hydro power plants (which currently make up 3 – 4% of total power generation), not all of this can be regarded as DG.

With regard to cogeneration, a target has been set by a voluntary agreement between the major industry associations, that 20 – 23 million tons of CO_2 emissions shall be avoided through the modernisation of existing and construction of new cogeneration plants. Based on this target, the Cogeneration law of March 2002 sets bonus payments, which have to be paid to cogeneration plant operators. This law is meant to support the development towards the CO_2 reduction goal. In order to reach the target, the electricity generation in cogeneration plants would have to be expanded from approx. 50 TWh/a in 2000 to 100 TWh/a in 2010. Again not all of this can be regarded as DG.

3.4.2.1 Administration of the environment and nature resources

The opening of the electricity and gas markets to competition took place in the context of commitments by the European Union to achieving reductions in the emissions of greenhouse gases. There are numbers of political initiatives introduced to achieve this, amongst them is introducing renewables, and measures and Directives to reduce demand for energy (f. ex. in buildings). Another issue here is the introduction of the ETS.

Germany has a VAT rate at 16, and the average energy tax for electricity is above 15 EURO/MWh (EU, 2005). Concerning renewables, the support mechanism is the feed in tariff. In 2003, 2900 MW of renewables/CHP were built into the German capacity.

3.5 Conclusion qualitative analysis

Generally the power market's special features compared to other markets, makes it especially vulnerable for competition limiting behaviour. The small demand side price sensitivity causes big changes in price due to only small changes in supply. Also, as a consequence of the capacity limitation, even smaller companies have possibilities of exploiting market power in periods of high demand (by adopting their capacity to the demand). And the generally high barriers to entry makes it possible for companies to increase prices considerably without facing the threat of new entrants.

However, in the German market there are several factors contributing to the picture drawn above.

- The significant market concentration
- TSOs, vertical integration
- Balancing services
- Lack of transparency
- Lack of power in the regulating authorities
- Cross-border system

If the liquidity in the future market gets to low, this will have several consequences concerning market power:

a. It gets easy to manipulate, for those of the market participants with amounts of cash and also hedging in the way that they control other parts of the market. (In other words, easy to manipulate for the four major participants in Germany)
b. There will be uncertainty about the price development, as the other traders do not know whether a player can use their market power to change the price or not.

c. This leads to less trading and investment in the future market, which again leads to even greater possibilities for the four major players to influence on the prices.

By abusing their market power, the companies can maintain several benefits:

1. They can sell on the OTC market for a higher price, as the exchange is a note board for the electricity prices in the present and the future.
2. Higher uncertainty and the possibility of manipulation keep new players from entering the market. The major companies can “read” the new entrants marginal cost and price them out of the market.
3. They also keep traders away, as the market is not transparent in the way that the four major companies alone have 90 % of the liquidity in the future markets, and the traders need liquidity to enter in the market.

As the German market is to a large extent controlled by vertical integrated companies, which both operate as TSO and suppliers in their areas, the market power held by these companies is massive.

The general intransparency in the German power market also holds for the balancing market. There are also monopoly positions in the different areas, held by the sister companies of the area’s grid company. One of the main price increase arguments brought forward by the Grid operators is the high balancing cost. As most of the trading takes place outside the EEX and the information concerning transactions are closed, the market is not transparent, leading the way for non-competitive actions to influence on the price.

The main problems considering the auction system used in the cross-border trading can be summarised as:

- There is no risk for the company holding the auctions
- The four large companies in Germany have a triple-role in this system; generator, owner of capacity, and market organisator

- The company holding the auction makes money by dragging other companies into a bid-round.
- There is inefficiencies in this system, as there are separate trading on all of the borders, instead of a system where there is major control over the cross-border trading

Possible solutions on these problems are:

- Financial capacity auction, with similarities with Asian options (passive). Physically there has to be market coupling
- There should be intra-exchange trading with a large market organisator (TSO) for the whole European system

Market concentration is the important issue in the German market. There are four market participants that control 81 % of the market and this is a very high number, as also the EU points out. The concentration is visible both in the way the major participants invest in smaller companies and in the customer relations in each area.

As the German market was deregulated with no regulator, the control and power of the regulating authorities were lacking. This has opened even more possibilities for the abuse of market power, and the intervention possibilities have been few. Due to this, the German market is a system that has not been able to make important changes concerning competition.

However, it is yet to be seen whether the new regulator will have the necessary authority to change the competitive barriers and fulfil the intention of a free and totally open market.

4 Analysis of the prices in the German Electricity Market

4.1 Distinctive characteristics of power prices

In this chapter we will outline some of the factors influencing power prices at EEX and underline some of the distinctive characteristics of the price movements. This is important to understand how prices develop over time, and forms the foundation for the analyses in this thesis.

4.1.1 Non- storability

Electricity may be considered as a flow commodity, with very limited storability and transportability. Both limit the possibility of carrying electricity across time and space, and are crucial factors in explaining the behavior of electricity spot and derivative prices compared to other commodities. The arbitrage possibilities across time and space, which are based on transportability and storability is seriously limited, if not eliminated [Lucia and Schwartz, 2002]. Some of the expectations caused by this special feature are; spot prices that are highly dependent temporal demand and supply conditions, and a different relationship between spot and forward prices than for other commodities.

In a Hydro Power based system, as Nord Pool, the producers can indirectly store electricity in water reservoirs. However in the German, thermal system, the producers have no means of storing, except from the possibility of storing the fuel.

4.1.2 Intraday, day of week and seasonal cycles

The non- storability of electricity makes electricity delivered at different times and on different dates to be perceived as a distinct commodity. In other words, prices are highly dependent on the electricity demand and their determinants in every precise moment; business activity, temporal weather conditions, etc. Therefore, distinguishing between on- peak and off- peak prices, or among future and spot prices corresponding to different time periods, such as seasons is indeed important in power markets [Lucia and Schwartz, 2002].

4.1.3 Mean reversion

Due to the fact that competitive electricity markets are relatively new and long historical data of liquid spot and derivatives prices don't exist, an undisputed agreement of the long- term movements of prices is not established. However, in Energy Risk (1998) Pilipovic defend mean- reversion as the most suitable method for modeling energy prices, and has received support from several published papers on energy prices. Mean- reversion means short- term deviations in prices returning to an equilibrium (not necessarily stationary) in the longer run. The argument supporting this theory is that when facing high prices, producers with high costs will enter the market and subsequently prices will drop. Similarly, facing low prices the same producers will withdraw from the market, leading to an increase of prices.

4.1.4 Time varying volatility

The changes in electricity prices are stochastic, and the volatility gives the strength/size of these movements. Volatility is often modeled stationary to simplify, although itself can be volatile and should be modeled as a combination of a time-varying and a stochastic term [Pilipovic, 1998]. Excessive and time- varying volatility with evidence of heteroscedasticity both in conditional and unconditional variance characterizes electricity prices. The former reflects the influence demand, capacity margin and trading volume has on volatility levels, and the latter describes the observed clustering of tranquil or unstable periods (GARCH effects), specifying volatility as a function of its lagged values and previous disturbances [Bunn and Karakatasani, 2003]. As mentioned in chapter xx.xx, Bessembinder and Lemmon [2002] predicts that a pattern exists for the volatility of spot prices, higher (lower) during periods of high (low) demand.

Lucia and Schwartz (2002) find an annual average spot price volatility in Nord Pool of 189 % during the period from 1993 until 1999. Volatility calculations from other electricity markets show similar numbers, and are orders of magnitude higher than for other commodities and financial assets. We come back to the volatility for the German Spot Market (EEX) later in this chapter.

4.1.5 Extreme prices/price speaks

As a result of the distinct features of the electricity markets, erratic extreme behavior with fast- reverting spikes, as opposed to "smooth" regime- switching [Kaminski, 1997], and non- normality manifested as positive skewness and leptokurtosis often characterize prices in electricity markets.

Lucia and Schwartz [2002] find a kurtosis of 3,5 for Elspot at Nord Pool during the period from 1993-1999, while a normal distribution has a kurtosis of 3. This indicates higher possibility for extreme prices than for a normal distribution. In the same paper they find positive skewness indicating that the probability for high extreme prices is higher than the probability for low ones.

4.1.6 Fundamental drivers in the German Power Market

Another characteristic of power prices is the underlying fundamental drivers for the market. These are the fuels; gas, coal (and oil), and also increasingly CO_2, due to the Kyoto Protocol and the obligations for the EU (including Germany) to meet the demands set.

As an introduction to this topic we have to focus on the development of the pan-European electricity market. Competition in electricity and gas markets remains a key element of the drive in the EU to develop a single market in goods and services. The liberalisation process started in the early 1990s following the liberalisation of the England and Wales and Norwegian electricity markets. The EU adopted a directive on electricity liberalisation in December 1996, and this directive became a catalyst for wider electricity liberalisation across Europe, but the progress was rather slow and patchy. As a consequence, the EU was led to once again go inside the liberalisation measure that led to a new and more robust set of liberalising measures in June 2003. These measures are now being transposed into national law among the members of the EU and this should yield further liberalisation. The critics of a more liberalised market is raised on the questions on how to combine the competing objectives of competition, security of supply and environmental protection.

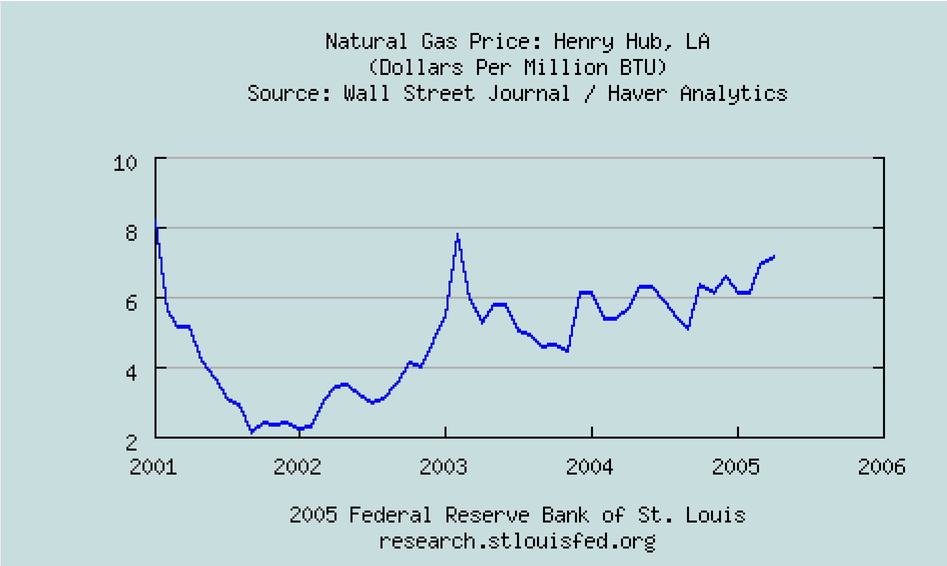
European power flows increasingly depend on market fundamentals rather than historic long-term contracts. When there exist significant price differences between to markets, there will be a flow across boarders. An important observation is that even when market prices are similar and there exist capacity, price changes in one area will affect the prices in other markets. We can see this from figure 4.1.1, which shows the correlation of German and French prices in the period 2002-2003. More about cross-border trading can be found in the qualitative analysis, chapter 4.2.

4.1.6.1 Gas

The liberalisation of the gas market in the EU lags significantly behind the liberalisation of the power market. On of the problems is that of the market concentration and this is why the original gas directive from 1998 did not help in the development in the way the electricity directive did. As a consequence the directive was revised in 2003, but still the only truly liberalised market in Europe is the UK market. There exist some limited wholesale trading at other points, such as in the Netherlands and Belgium and there is more attention on development of new hubs. However, there is little real competition within Continental gas markets.

Gas prices are nevertheless a fundamental determinant of EU power prices, particularly in the UK, since there exist gas-fired stations. Along with coal-fired plants the gas stations featuring at the margin according to the relative economics of burning gas and coal. Correlation can be very strong at times. Gas prices in Continental Europe remain largely driven by oil-price indexation clauses in long term purchase contracts. With further liberalisation (more flexibility) the linkage to oil prices should in time become less prevalent. Gas prices will respond to new supply sources (LNG, pipelines from Norway, North-Africa etc.) as well as to the liberalised competition. Another consideration is that according to the new CO_2-trading, a great part of the carbon-intensive coal-burn will be replaced by gas. In figure 4.1.2 we see the development of the gas price in the years of the trading on electricity exchanges in Germany. In Germany, gas is a significant driver for the peak price.

Figure 4.1.2: Gas price development 2001 – 2005 (Source: Wall Street Journal)



4.1.6.2 Coal

Thermal coal imports into the EU (UK, Germany, Spain and Italy) increased from 90 million tonnes in the mid-1990s to 135 million tonnes in 2003. This means that indigenous coal is being replaced by imported coal and has two main consequences:

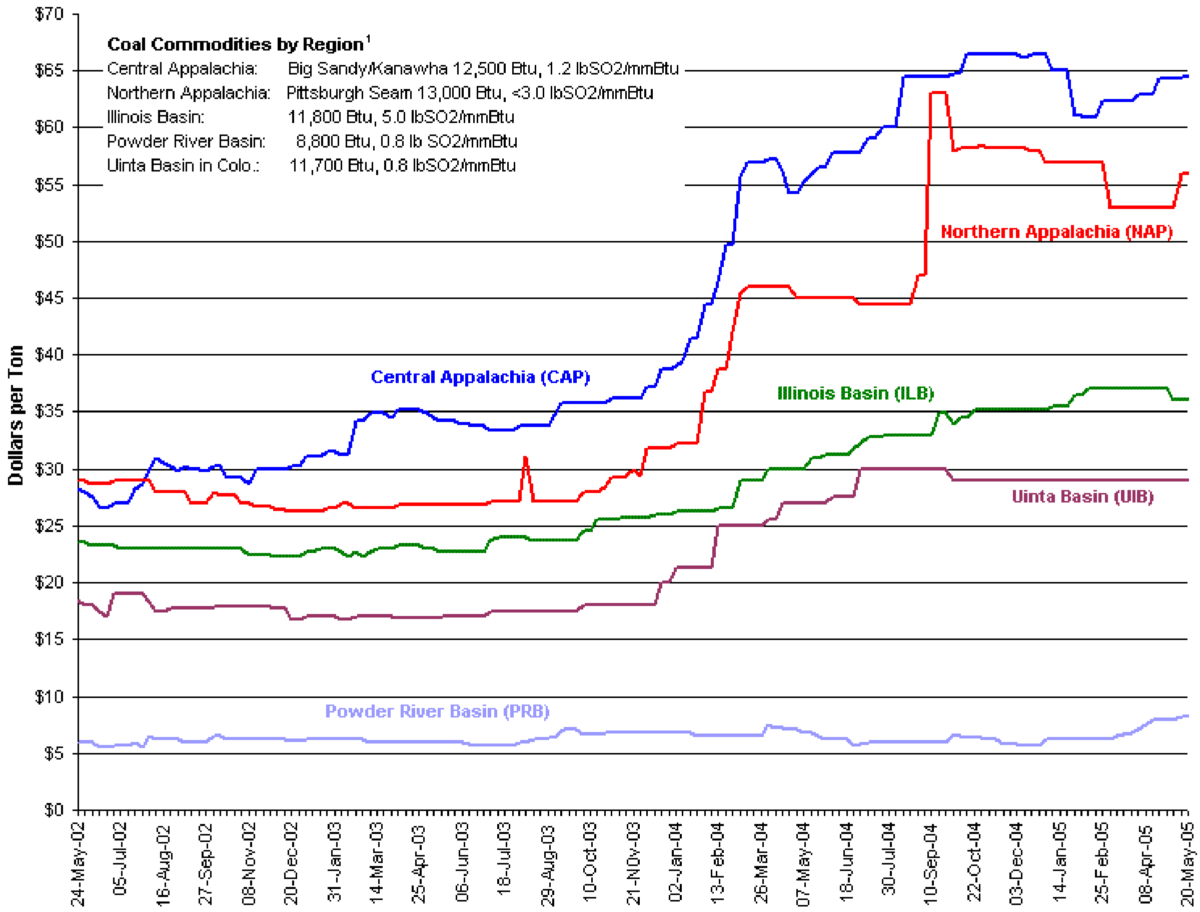
- Generators increasingly compete for similarly priced coal from the same sources. A generator's competitiveness now depends on its efficiency and success in hedging than on cheap (in many cases subsidised) coal.
- The distant origin of the coal (South Africa, Colombia, Indonesia and Russia) leads to increased importance for ocean freight and port conditions (logistics) in the delivered price of coal.

As a consequence the generators must take a global approach to sourcing their coal and pay more attention to global economic activities. Local sources can protect against supply interruptions and imported coal can relieve constraints on greenhouse-gases that limit local coal burn.

Europe burns less than 10 % (500 million tonnes) of worldwide coal production (5,3 billion tonnes) and therefore Europe remains a price taker. This means that the European energy markets don't impact on the coal price, as the Asian and American demands do. The European development including liberalised power markets, uncertain spark spreads and increased imports and exports have increased the volume uncertainty. Thus, while much indigenous coal is still traded on long-term contracts, spot markets are increasingly important for marginal volumes of coal (both imported and indigenous). Increased volume risk has also led to indexed physical purchase contracts, combined with more active trading of coal derivatives and hedging of the coal-power price spread. In addition to swings in the burn patterns, increasingly dependence on physical spot markets rather than long-term purchase agreement has contributed to more volatility during the last few years.

There are several factors that influence on the fluctuations of the price. To exemplify some of these factors, we go deeper on what happened when the price leapfrogged during a few months in 2003. First of all, Europe had been through a very cold winter, with some extremely low temperatures during January and February. This caused high production all over Europe and the Nordic countries were in an import-situation (hydro was not sufficient). In addition the summer came warm, and as a consequence the demand for cooling during the summer was very high. A dry summer also led to low hydro production and shortage of cooling water for thermal plants, which meant less nuclear power production. Other factors were low wind power output and a strike in France that led to limited export. The consequence of these factors was insecurity in demand and large grid disturbances, and so coal became more important than ever. The price increased to twice the earlier level. We can see the development from figure 4.1.3.

Figure 4.1.3: Coal price development 2002-2005



The coal market outlook:

- Demand growth within power generation, China and India main growth markets
- Long term prices determined by market fundamentals
- No reserves problems
- Higher degree of international trade
- OECD demand prospects will be highly influenced by environmental factors

The regional outlook for Europe:

- Coal looses market share to gas, if gas prices are low and stable and if gas supply is secure
- Environmental policies
- Imports to grow from 223 mt in 2002 to >300 mt in 2020

The market fundamentals here referred to is the coal itself and the shipping costs. It is expected that the cost of coal will lower to cost efficiency in mining and transportation, but that this will be offset by higher oil costs for transportation. There are some key factors to watch for the future development of the price:

- Development of coal supply/demand balance
- Freight rates
- Gas prices
- Costs for CO_2 emissions, CO_2 capture

The freight elemental in the coal price has increased from about 5 % before 2003 to about 25 % by the end of 2003, as we can see in figure 4.1.4.

4.1.6.3 Impact of carbon trading on the electricity market

In January 2005, the EU saw the start of its new carbon emissions trading scheme, which is part of the EU's efforts to control CO_2 emissions under its Kyoto Protocol commitments. This scheme covers large carbon-emitting industry in the 25 member states. The key elements of the scheme is:

- Each installation covered by the scheme requires a permit to emit CO_2.
- Each EU member state will issue emission allowances for those installations covered by the scheme
- This allowances will be tradable between installations and across EU
- At the end of each year, each installation must surrender allowances equal to its emissions of carbon

Electricity generation activities account for the vast majority of CO_2 covered by the scheme and thus CO_2 will become a major driver of European electricity prices from 2005 and on. Since the intent of the scheme is to reduce CO_2 emissions, the generators will receive fewer allowances for CO_2 than their former producing levels indicates. The generators now face the choice between:

- Limiting generations to the allowances received

- Generating more electricity and buying additional allowances from other participants
- Generating less electricity and selling allowances from their initial allocations

Theoretically, as generators frame offer prices that reflects the opportunity cost of generating (the cost of buying or not selling an allowance), the price of the CO_2 should factor into the power price. This will also cause difference between power produced from coal and power generated in gas-fired stations, since coal-fired generation emits roughly twice as much CO_2 as gas-fired generation.

From 2005 onward the power traders need a fundamental understanding of the CO_2-allowance market and the associated drivers of CO_2-prices. For a range of gas and coal prices, an associated "break-even" price for CO_2 can be calculated. This is illustrated in figure 4.1.5, which shows a simplistic calculation of the equilibrium price for CO_2 given relative gas and coal prices. There are some significant external drivers of the future price of carbon:

- The degree to which the fungibility of CO_2 allowances across time and across EU results in correlation between annual power prices and convergence between power prices across the EU.
- The extent to which the burden of meeting the EU's Kyoto commitments falls on the scheme versus other CO_2 emitting activities.
- Linking directive
- Environmental legislation

The first month of the carbon trading has given some interesting results. In the beginning, the majority of the trading companies found the price too high, but there was a change in March. To be competitive, gas need a certain CO_2 price, so that the marginal cost of gas power is equal to or just below the marginal cost of coal power. The price of the ETS has now stabilised in the European market.

4.2 The data

In this chapter we will try to focus on the issues mentioned above in our analysis of the available price data for the German Market. Since the EEX is a relatively young exchange, the number of data available is small, which decreases some possibilities for the statistical part of the analysis. However, we try to give an overview of the parts we think should be included in a thorough analysis, and we think should be used when there are more data available in some years.

The analysis done in this master- thesis is based on historical data on futures and spot prices from EEX covering the period from June 2000 until April 2005. These were the data available to us from the EEX. The spot data used is daily averages for the base and peak hours (explain more about how this is calculated).

4.2.1 Spot prices

Figure 4.2.1 shows the monthly average Base (average all hours) and Peak (8-20) load prices for the period between June 2000 and May 2005. The graph can be divided into three major periods. Two periods recognised by relatively "normal" prices and one period with volatile and unpredictable price movements. The first period from June 2000 until November 2001 is a stable period, as we see the Base prices varies below 23 Euros/MWh and Peak prices varies below 28 Euros/MWh. Then follows a period of volatile and unpredictable prices from November 2001 until late 2003. First we see three months of extreme prices, November 2001 to January 2002, peaking in December with monthly average base prices at around 42 Euros/MWh and Peak Prices at 61 Euros/MWh. A central occurrence that can be related to this spike, is the bankruptcy of the American energy giant Enron. While Enron did not control much capacity in Germany, contracts had to be renegotiated. As a result, the prices needed to increase to reduce the losses, and German wholesale prices reached an all- time high in December 2001 (Müsgens, 2004)

Following this extreme period, there were four “normal” months before peak prices increased during the summer of 2002 and widened the gap between base and peak prices to reach a new level that seems to have held for the rest of the analyses period. This increasing gap can be seen from figure 4.2.2. Some of the possible explanations for this increased gap could be increased skewness in the prices, increased general demand (less difference between the demand in the summer and the demand in the winter), market power (the prices are held high due to abuse of market power by the four major companies, Müsgens), new volatility pattern, increasing prices in the fuel market (will give highest leap for the peak price over time.

Prices peaked again in January and February 2003 due cold weather conditions, with temperatures down to – 10 °C. This is the coldest single day temperature for the entire price period.

In the period June to August 2003 the prices peaked and reached record levels for summer months. The peak almost reached the 60 EURO mark, while the spread between peak and base was the highest ever, with a difference over 20 EURO at maximum. This was caused by several extraordinary events happening at the same time (heat wave, causing high consumption during peak hours and to warm cooling water for nuclear plants, shortage of coal supply etc.). The summer of 2003 is discussed further in the section “Coal” (4.1.6) above.

The last period with stable prices then follows from November 2003 to January 2005. During this period the Base prices varies between 25 and 32 Euros/MWh whereas the Peak price varies between 32 and 42 Euros/MWh, and has clearly reached a new equilibrium level. Due to all the extraordinary events happening between the two stable periods it is difficult to state the exact time for the shift in prices.

Then in February 2005 we see a big jump in prices again due the start of the Emission trading. This time the prices are expected to stay at a higher level, but it is to early to say exactly what the equilibrium level will be. Another issue concerning this is the difference between base and peak. With higher emission costs for base production, the spread could be likely to decrease. However, the question remains of what type of capacity will be built to meet the increased demand in the years to come, and what capacity will be built to replace nuclear power.

Figure 4.2.1 Monthly average base load and peak load prices

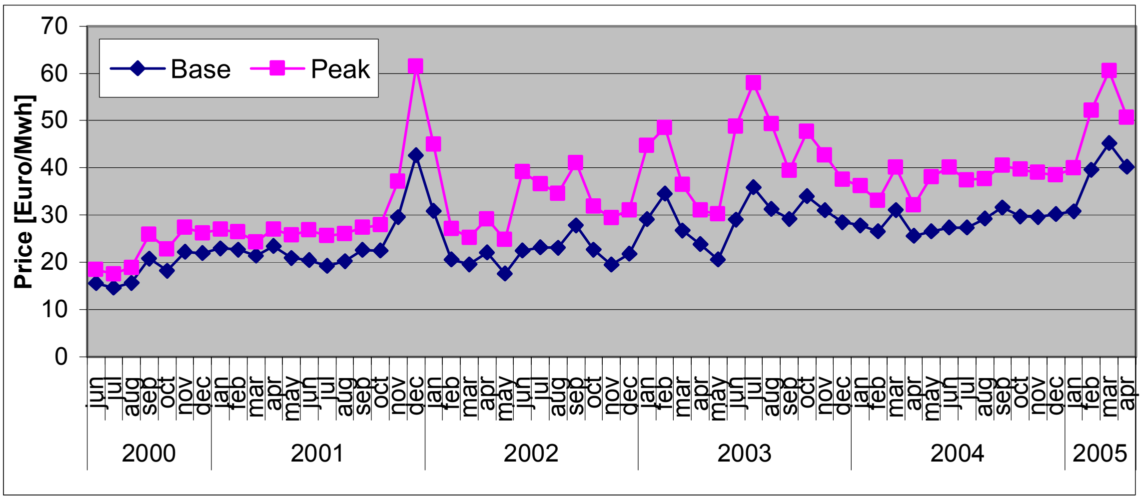
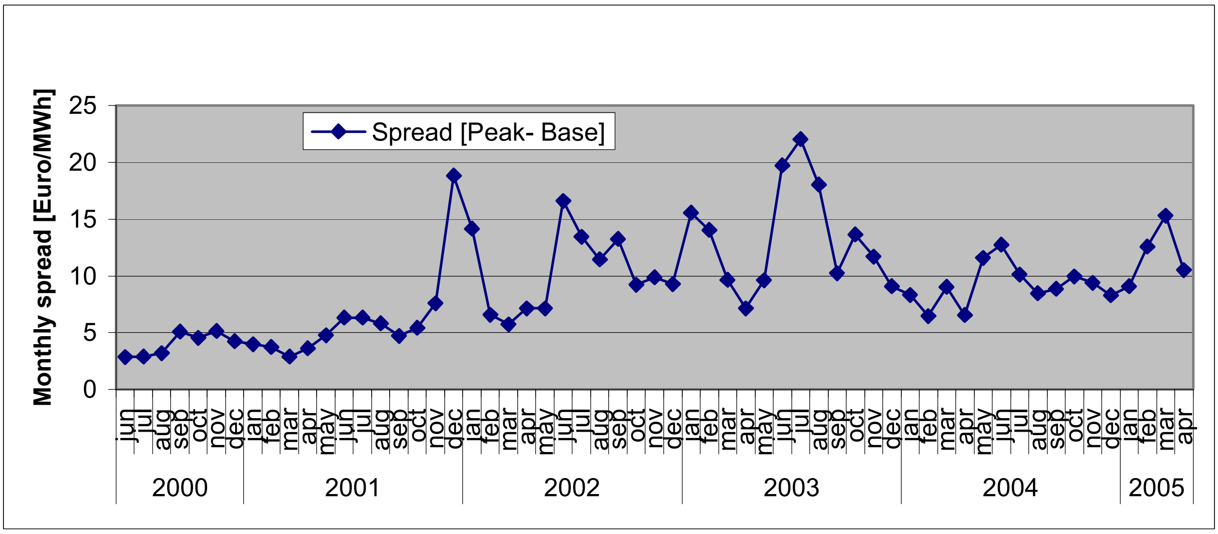


Figure 4.2.2 Monthly spread between base load and peak load prices



4.2.2 Volatility

Table 4.2.1 shows the volatility we calculated for Base and Peak load prices in the German power market during the period from June 2000 until April 2005.

Table 4.2.1: Volatility in the Base and Peak price, June 2000 – April 2005

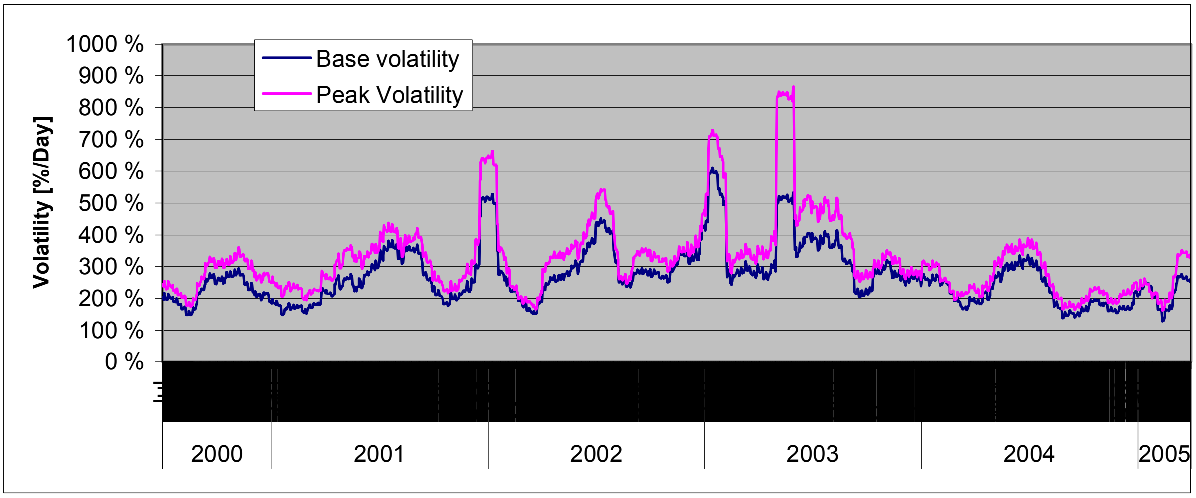
	Annual volatility Base	Annual volatility Peak
2000	220 %	268 %
2001	283 %	343 %
2002	301 %	349 %
2003	343 %	446 %
2004	222 %	257 %
2005	216 %	261 %
2000-2005	280 %	341 %

Comparing with Nord Pool, Lucia and Schwartz calculated a volatility of 189% for Nord Pool during the period from 1993-1999 of 189%, and Vallevik and Øyan [2004] calculated a volatility of 199% during the period from 11. January 2001 until the 31. December 2003. As we see from table 4.2.1 the German volatility is substantially higher both for Base and Peak prices. Some of the explanation for this could be; the small demand side trading on the exchange (much higher number of generators trading on the exchange for hedging purposes, the consumers mostly use the OTC or other bilateral agreements), the price increases are very significant with higher demand, possibilities for manipulation caused by abuse of market power in the way of with-holding capacity. This will have a greater influence on the peak price than on the base price, which we can see on the volumes. The influence will be greatest in the summer as the peak jumps (increases) are at the largest.

The years 2002 and 2003 has the highest volatility, which is explained by the special occurrences (earlier in this chapter) during these years, leading to price spikes and great variability. The only "normal" years so far since the opening of EEX, without any extraordinary occurrences, is 2000 and 2004. These years are also the ones with the lowest volatility, and is an indication of what level of volatility that could be expected if, and when the market stabilizes.

As we see the yearly changes in volatility are rather big, as a consequence calculating with constant volatility in the German power market would be a huge mistake. We also calculated a 30 days moving average of the volatility to see how the volatility changes during the year, the results are shown in figure 4.2.3

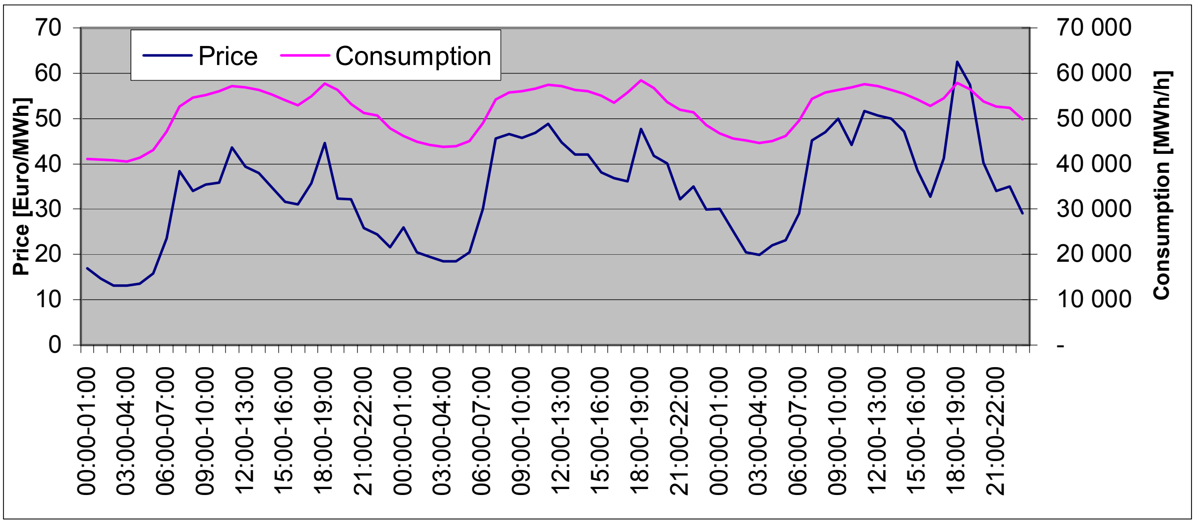
Figure 4.2.3: Volatility peak and base, % Day



4.2.3 Intra-day, day of week and seasonal cycles

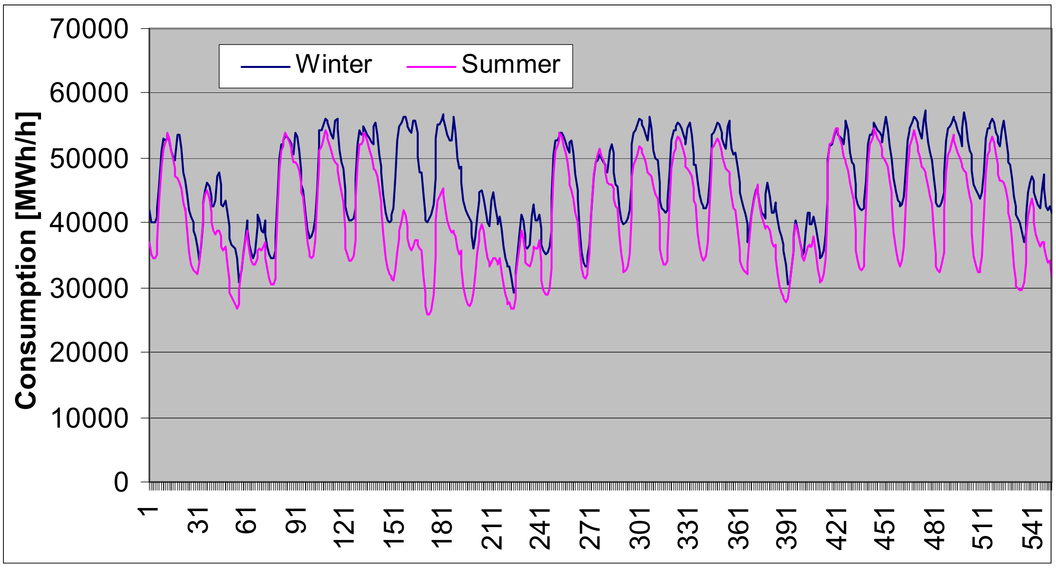
The behaviour of the German electricity prices is characterized by several of the distinguishing features of electricity prices, beginning with their regular intra-day variations. Figure 4.2.6 shows the hourly prices and demand from January 10 until January 12 2003, and the intra-day pattern can be observed quite clearly. As expected prices are on average greater during weekdays when the demand is greater, also the weekdays have a very similar pattern. The price begins to rise at around 6 am as people wake and the workday begins. The price increase continues during the day and has its first peak with demand at roughly 12 a.m. Then prices decrease for a couple of hours before it rises and peaks again at roughly 7 p.m. Prices begin to fall again as the day closes. As we see from this graph it is clearly that prices are mimicking demand.

Figure 4.2.6: Hourly price and demand, January 10 – January 12, 2003



This is data for the winter, data for summer months show similar intra- day patterns, only with some distinct differences. Figure 4.2.7 shows demand for both summer and winter months.

Figure 4.2.7: Consumption patterns, summer (June 13 to July 10) vs winter (January 17 to February 11) 2003



As we see off peak demand for summer is considerably lower than off- peak for winter. However, peak hour consumption is almost the same as for winter months. This creates a greater gap between off- peak and peak demand during summer, and as we see in figures 4.2.8 and 4.2.9 this causes higher prices for peak hours during summer months with equal consumption as winter. A contributing factor to this is the nuclear power plant maintenance during summer months.

Figure 4.2.8: Hourly prices and consumption 8- 17 February 2003

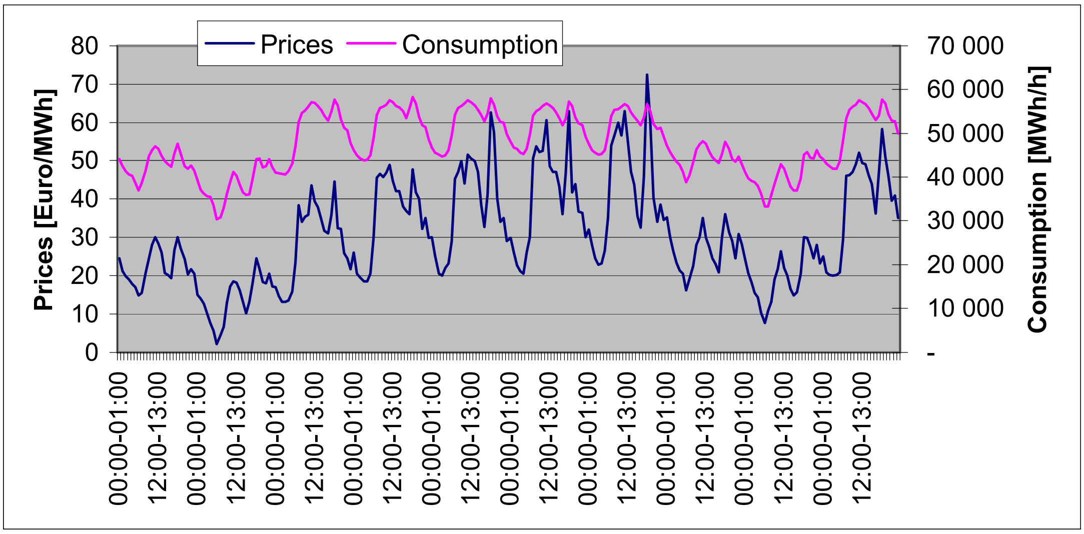
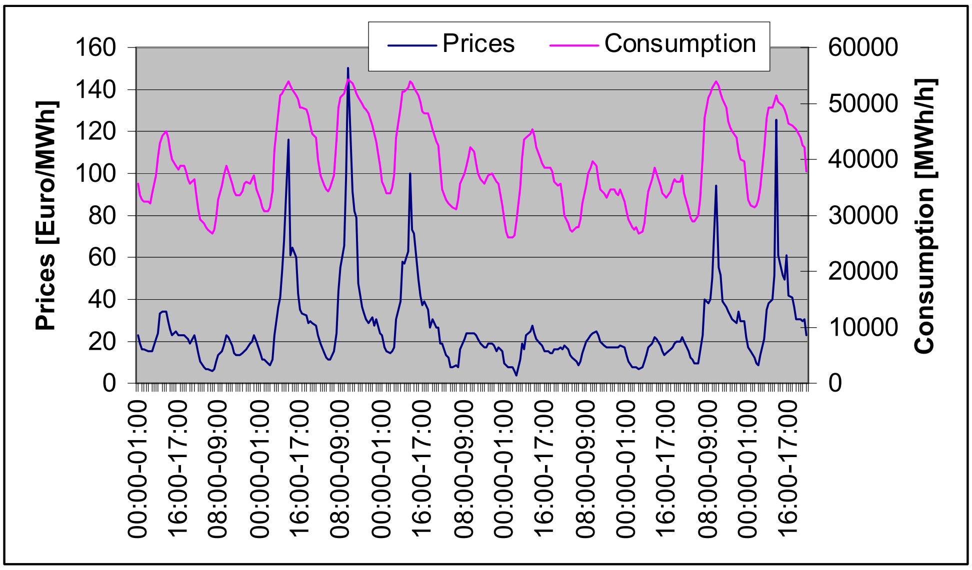


Figure 4.2.9: Hourly prices and consumption 14-24 June 2003



From these figures (4.2.8 and 4.2.9) we can also very clearly see the weekly pattern present in the German electricity prices. The weekdays show similar consumption and price pattern, whereas Saturday and Sunday show considerably lower prices and consumption. The obvious reason for this is the reduced industrial consumption during weekends.

As opposed to the Nordic market, the German electricity market does not show a strong seasonal variation of spot prices, although the demand definitely has a seasonal pattern. Figures 4.2.10 and 4.2.11 shows historical base load prices and consumption for 2003 and 2004.

Figure 4.2.10: Consumption and base-load prices in Germany 2003.

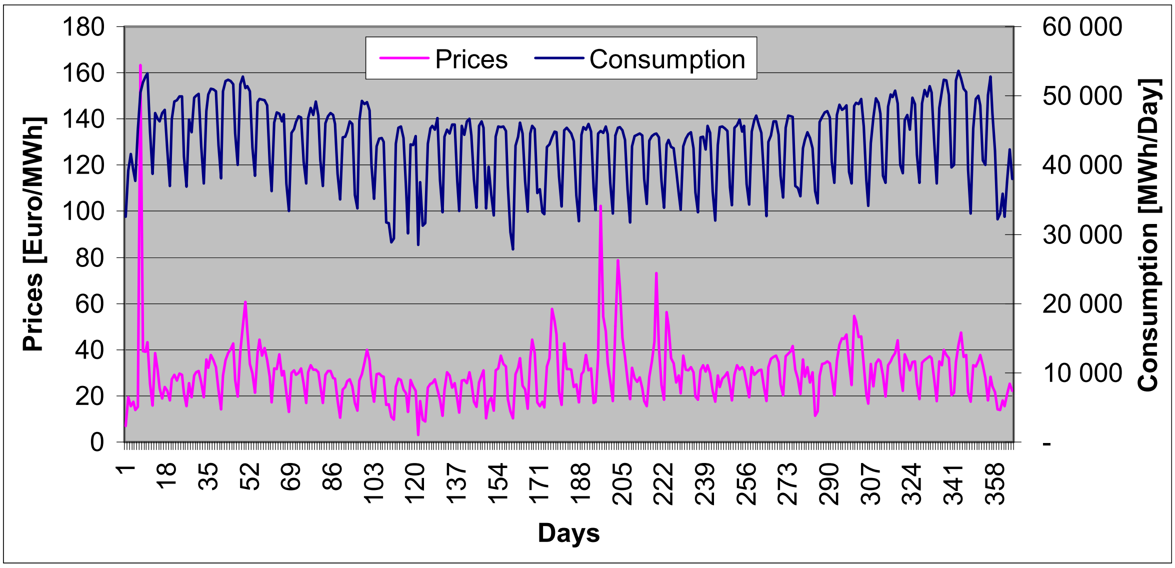
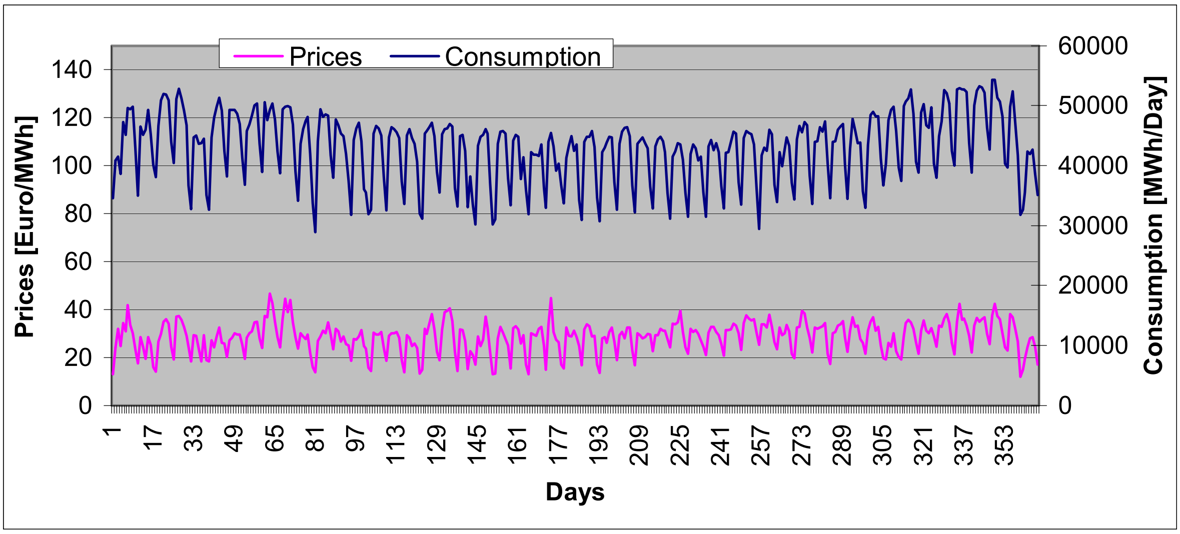


Figure 4.2.11: Consumption and base-load prices in Germany 2004.



There are several reasons for this. First, maintenance of the nuclear base load plants is executed during the period from April to September; this will of course contribute to higher base load prices in this low demand period. Secondly, although the demand is lower during summer, as mentioned earlier, the gap between off peak and peak demand increases in periods of high temperatures (cooling need). As a consequence peak load plants with higher variable costs are used, causing increased peak prices that contribute to decreasing the seasonal price pattern one would expect from the watching the yearly demand curve. Studying the historical base and peak load prices (figure 4.2.12 – 4.2.15) we see that the seasonal variations in German electricity prices is more of a variation in volatility than a distinct price variation, which follows demand.

Figure 4.2.12: Daily base load prices in the German electricity market June 2000- 2002

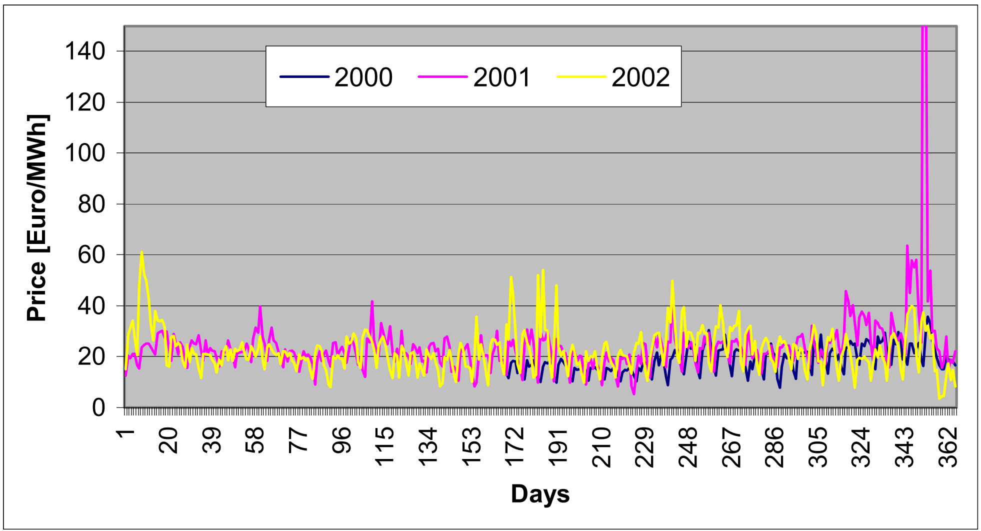


Figure 4.2.13: Daily base load prices in the German electricity market 2003 - April 2005

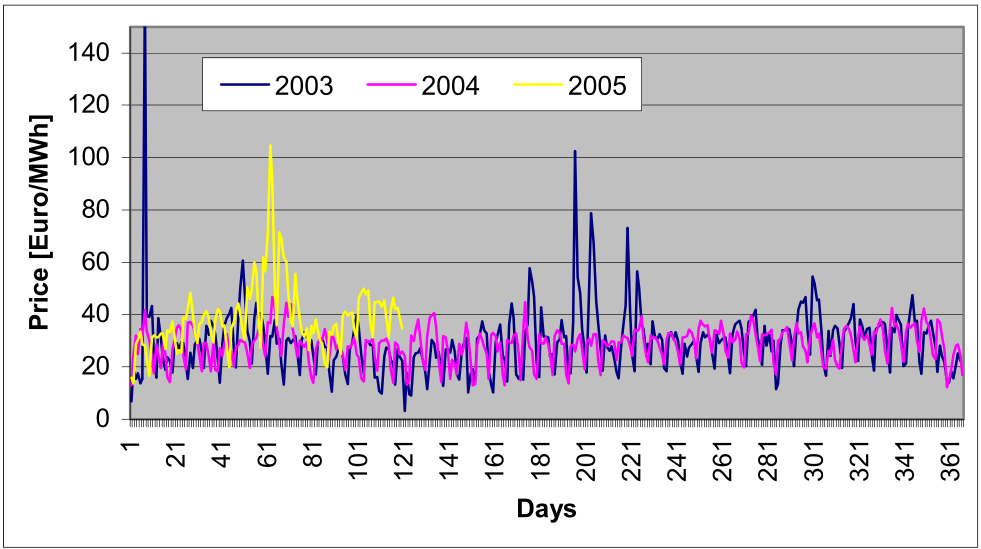


Figure 4.2.14: **Daily peak load prices in the German electricity market June 2000- 2002**

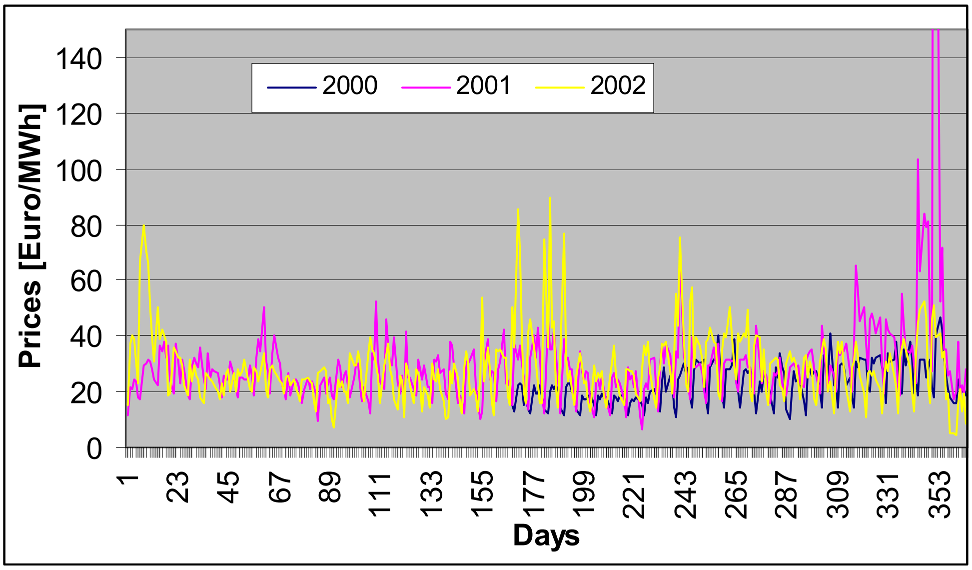
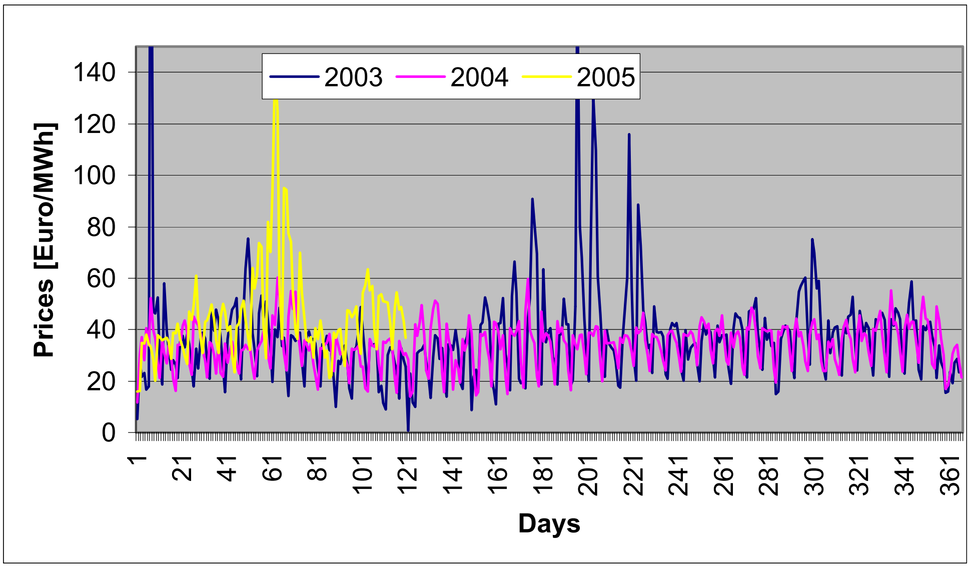


Figure 4.2.15: **Daily peak load prices in the German electricity market 2003 - April 2005**



We see that the possibility for periods of high (spiky/volatile) prices increases during the winter when demand is high and the available capacity margin is limited, and during hot summer days with a large peak demand caused by the need for cooling. The conditions leading to low prices in the German market are; big amount of unregulated power in the system, high wind power generation combined with a weak demand side. The prices also show signs of mean- reversion, to a non- stationary mean. This becomes quite clear when watching figure 4.2.1, which shows the average monthly prices. In the first stabile period the base mean was clearly around 20

EURO/MWh and the peak mean was around 25 EURO/MWh. Then through the period of very volatile prices it is not easy to spot the mean, however when the prices settle again in the end of 2003, they clearly return to a new mean. The base mean was now around 30 EURO/MWh, and the peak was around 40 EURO/MWh. In an efficient market one would expect this mean to be determined by the long- term fundamental price movements. In the following figures we show the historical development of …. And the prices.

4.2.4 Extreme prices/ price spikes

As mentioned in section … electricity spot prices are often characterized by positive skewness and leptokurtosis, in this section we present our calculations of skewness and kurtosis for the German market. We then use this results as input in our hypothesis for the risk premiums in chapter …..

We calculated the skewness and kurtosis for the base and peak load prices during the period from June 2000- April 2005. For baseload prices we found a kurtosis of 77,0 and a skewness of 5,67. For peakload prices we found a kurtosis and skewness of 161,0 and 9,16 respectively.

This is rather high numbers, compared to what Lucia and Schwartz [2002] find for NordPool. However, in this respect it is important to stress that the methods that are usually used for calculating skewness and kurtosis (also what we used here), are rather unstable because they are very sensitive to extreme prices.
Lucia and Schwartz [2002] find a kurtosis of 3,5 for Elspot at Nord Pool during the period from 1993-1999, while a normal distribution has a kurtosis of 3.
According to the model of Bessembinder and Lemmon, presented in chapter…, one of the factors influencing the size and sign of the forward premium is the skewness of spot prices throughout the year. Figure … and … show the monthly skewness for electricity prices in Germany.

Figure 4.2.17: monthly skewness of peak load spot prices.

	2000	2001	2002	2003	2004	2005	average monthly
January		-0,34	0,99	4,69	-0,33	-0,27	0,95
February		0,35	-0,87	0,21	-0,48	0,58	-0,04
March		1,07	-0,57	-1,01	0,04	1,36	0,18
April		0,85	-0,51	-0,14	-1,14	-0,58	-0,30
May		-0,31	-0,35	-0,71	-0,13		-0,37
June	-0,45	-0,16	0,97	0,37	-0,36		0,07
July	-0,48	-0,16	1,74	2,03	-1,27		0,37
August	0,05	0,72	1,27	1,56	-0,30		0,66
September	-0,41	-0,63	-0,37	-0,42	-0,83		-0,53
October	-0,63	0,12	-0,33	-0,14	-0,88		-0,37
November	-0,52	0,10	-0,24	-0,66	-0,32		-0,33
December	0,80	3,40	0,04	0,05	-0,64		0,73

Figure 4.2.17: monthly skewness of peak load spot prices.

	2000	2001	2002	2003	2004	2005	average monthly
January		-0,24	1,13	5,04	-0,31	0,08	1,14
February		0,53	-0,32	0,17	-0,36	0,86	0,17
March		1,48	-0,46	-0,80	0,53	1,46	0,44
April		0,97	-0,39	-0,24	-0,95	-0,44	-0,21
May		0,07	-0,19	-0,66	-0,12		-0,22
June	-0,41	-0,03	1,42	0,57	-0,20		0,27
July	-0,34	0,16	2,04	2,30	-1,12		0,61
August	0,51	1,64	1,80	1,91	-0,46		1,08
September	-0,35	-0,29	-0,19	-0,50	-0,65		-0,39
October	-0,49	0,54	-0,42	0,30	-0,80		-0,17
November	-0,35	0,31	-0,32	-0,56	-0,22		-0,23
December	0,81	3,71	0,08	0,11	-0,19		0,90

As we see for baseload prices, the skewness is on average positive for December, January, March, June, July and August, and negative for the remaining months. The results for the peak prices are equivalent, except that the average for February are positive.

5 Future Markets

Trading in futures contracts emerged in the agricultural sector. For years futures markets were confined to traditional agricultural products. However, in the past three decades there has been an explosion in the variety of products served by these contracts. The expansion started with new agricultural contracts (especially meat) and precious metals. The second stage of the expansion, starting in the 1970s, brought in financial instruments including currency, stock index contracts and interest rates. Then followed oil and a number of other industrial products. The fourth stage, which continues to evolve today, introduced options on future contracts. In the 1990s, pioneered by Norway and England, we have seen the development of futures markets for electric power. Germany was also an early starter….

Electricity forwards markets are immature compared to most of the other well-established forward markets. Useful insight can be learnt about the possible pitfalls for the electricity forward markets, looking at experiences from mature markets.
In this chapter we first discuss the main function forward markets traditionally serve, because they are essential for the understanding of the following chapters about criteria for well functioning markets and (hedging strategies? Skal det være med).

5.1 The main functions of futures markets

Three functions according to Treat(1990):

1. Price discovery
2. Risk management, hedging
3. Speculative opportunity, attract risk capital

But also other hypothesis from Adilov 2005 about strategic reasons for existence

5.2 Criteria for successful forward markets

John Elting Threat, a former director of the New York Mercantile Exhange (one of the world's leading exchanges for futures trading), points out 9 criteria for successful futures markets. Treat claims that in assessing the suitability of any new forward market, these conditions needs to be analyzed. Although these criteria not are a part of Fama's definition of efficient markets we think they might be just as important for the overall efficiency of a futures market. In the following chapter we comment upon each criterion with the new electricity forward market in Germany in mind.

5.2.1 Price volatility

Price volatility is perhaps the single most important criterion for it provides the basic economic justification for futures trading, which is to provide to the hedger against adverse price fluctuations. Price volatility is also necessary to attract risk capital from speculators and essential to ensure sufficient liquidity to maintain the market. Quantitative indicators: variations of plus or minus 20% per annum are assumed to be the minimum necessary to sustain futures trading. In general, the greater the degree of volatility , the more likely a futures market will survive.

Table …. Show the annual volatility of the German Peak load and Base load prices between June 2000 and April 2005, and as we see the German electricity market has no problems fulfilling the criterion. The annual Base load volatility fluctuates between 220% and 343 %, whereas the Peak load volatility is even higher fluctuating between 257% and 446%. However, figure … is more interesting showing a 30 days moving average of the volatility for the same time period. Here we see great intra- year variations, and periods of extreme volatility. Reaching a maximum of 867% for peak prices in the period with extreme prices during the summer of 2003. The maximum for base prices of 612% was reached during the winter of 2002\2003. The question is whether the volatility is too high, deterring speculators from the market because the risk is to high. The suspected use of market power by the major German electricity companies add to this problem, and could be some of the explanation why the liquidity at EEX is rather low.

5.2.2 Uncertain supply and demand

Uncertain supply and demand are generally the causes of price volatility and therefore generally present when price volatility is found. Quantitative indicators: in energy markets, which typically display rather high inelasticity of price demand, variations of plus or minus 10% during a two- year period should be sufficient to sustain futures trading.

While the long- time demand for electricity in Germany has shown a stable increase….. figures. The short time demand is highly volatile because of the stochastic element In temperature and weather conditions which naturally affect the power demand. The supply side capacity is also variable of different reasons: unexpected outages of power plants, variable inflow to hydro power plants, variable wind conditions at windmill sites, restrictions and breakdowns in the national and international grid, nuclear plant maintenance etc. As we see the variability in supply and demand should definitely be sufficient in the German power market, and these variations are also reflected in the very volatile spot prices observed in the market.

5.2.3 Deliverable supplies

If there are not sufficient deliverable supplies of the commodity meeting the quality, speculations, futures trading will fail. However, there must be some uncertainty about the sufficiency of supplies if the previous conditions are to be met. Quantitative indicators: storage capacity equal to at least 30 days demand is highly desirable.

Storage of electricity is generally not possible for consumers. The consumers do not need storage either as long as they are continuously supplied with sufficient quantities.

As mentioned earlier the non- storability of electricity is one of the main features that distinguish it from other commodities. And the electricity market is in this way different from other commodity markets, where supply and consumption does not take place continuously. In Germany as shown in figure … the generation is dominated by coal and ne…. These sources are relatively stable, and producers keeps storages of fuel to meet demand. And

5.2.4 Product homogeneity

Product homogeneity is another prerequisite. Futures contracts are traded on the premise that product taken on a delivery will meet certain quality specifications. The commodity must therefore have certain key characteristics that are quantifiable, allowing the clear differentiation of the product must be capable of being described by objective, quantifiable standards.

This should not be a problem in the electricity market, since the quality of electricity that consumers receive is generally both homogenous and high. There is always a small probability for grid breakdowns or interruptions in delivery, but the security of the German grid is normally very good.

5.2.5 Product perishability

Product perishability can be a deterrent to trading. In general a product should have a shelf life sufficiently long enough to permit storage and delivery as called for under the contract. In addition, the maintenance of stocks of the commodity will both facilitate deliveries and provide a ready pool of potential hedgers. Quantitative indicators: products should have a minimum shelf life of 6- 12 months.

Electricity is definitely a perishable good: it is non storable and with instantaneous supply and consumption. Storing power today for future physical delivery is only possible for producers with hydro- power reservoirs. Power kept as water in reservoirs has in that sense an infinite stock life. Other participants cannot buy power in the market today, store it, and then sell the power in the future, which is possible for most other commodities. This, however, does not prevent them from shorting futures contracts. Hedging is possible for both producers and other participants. Although electricity is a perishable good, this alone should not be a major deterrent to trading in the German market.

5.2.6 Market concentration

Market concentration is a difficult factor to quantify. A successful futures market is a highlt competitive market, marked by a large number of buyers and sellers. No one market participant, or plausible combination of market participants, should possess sufficient market power to exert unilateral control either in the short or medium term. Quantitative indicators: in general, the market share of the top five firms should less than 50% and the top ten firms should have less than 80%.

The reason for this requirement is that if one single company (or constellation of companies) actively influences the price development in the spot and/ or futures market on to it's own advantage. This would be unfair for other participants in the market and reduce their profit opportunities. A price setting and dominant producer may have both the incentive and ability to suppress the market (Amundsen and Singh (1992).

In the German power market the concentration is rather high. Our calculations ….
We see the market concentration in the German market as one of the biggest threats for a well functioning forward market. As long as several major companies has a possibility of exercising market power, and thereby infer large losses to other market players, new market players will be hesitant about entering the market.

5.2.7 Price information

Readily available price information is critical to market success. A sufficiently broad base of price information to permit evaluation of spot prices and their relationship to futures prices is of major importance. Convergence between these two prices as the

delivery period approaches is essential. Quantitative indicators: daily cash market prices should be available from at least two independent sources.
Her skal det skrives etter en at analysen av informasjonsflyten er analysert.

5.2.8 Unique trading opportunity

Unique trading opportunity is another key factor. If an existing market for a commodity has reasonable liquidity and is serving its customers well, it is extremely difficult to launch a copycat contract. Quantitative indicators: the ideal candidate would be a commodity that is not currently traded on any futures exchange in the world and has not been subject of a failed attempt in the previous five years.

EEX is the only official power exchange in Germany, and competition from other foreign exchanges is highly unlikely. However, there is also a market place for forward contracts in the bilateral market, and so far this is where the majority of the forward trading in Germany takes place.(tall) ….

5.2.9 Market timing

Market timing (and blind luck) are often critical to the success or failure of a contract. However, they are often impossible to forecast. Ideally, contracts should be introduced to coincide with high levels of cash market activity, to the extent these are predictable.

Er det flere punkt for elektrisitet spesielt (doktorgrad ollmar)

Summary

6 Future pricing theory

There are two ordinary views of commodity futures pricing. The first is the standard no arbitrage or cost of carry models. This is also known as the theory of storage. Classical literature on these models includes Kaldor (1939), Working (1948), Brennan (1958) and Telser (1958). The second approach used is based on equilibrium considerations. This alternative view splits a futures price into the expected risk premium and a forecast of future spot price. The classical literature on this approach includes Keynes (1930) and Hicks (1939). Recent work applied on the field of electricity includes Routledge et al (2001) and Bessembinder & Lemmon (2002). In the following sections we will outline the basis of these two different theories, and try to show how useful they are explaining the dynamics of the electricity forward markets.

6.1 The theory of storage

This traditional view explains the difference between futures prices and the spot price in terms of interest foregone in storing the commodity, warehousing costs and convenience yield on inventory. The convenience yield can be explained as the premium a holder is willing to pay to benefit from having the commodity instead of the futures. These benefits may include the ability to profit from temporary local shortages or the ability to keep a production process running [Hull, 2000].
Following the theory of storage, the futures price at time t for a contract with maturity at time T is given by the range [McDonald, 2003]

$$S_t e^{r(T-t)} + U - Y \le F_{t,T} \le S_t e^{r(T-t)} + U$$

where S_t is the spot price at time t, r is the interest rate, U is the storing cost from t to T and Y is the convenience yield for the period. If the convenience yield and storing costs are expressed as proportions of the spot price, the futures price can be expressed by the range:

$$S_t e^{(r+u-y)(T-t)} \leq F_{t,T} \leq S_t e^{(r+u)(T-t)}$$

The concept of convenience yield gives a no-arbitrage region for the forward price rather than a no-arbitrage price [McDonald, 2003]. This is because the average investor will not necessarily be able to earn the convenience yield, i.e. participants benefiting from holding the commodity physically are likely to hold the optimal amount already. Pindyck (1994) concludes that convenience yield is highly convex in inventories for commodities as copper, heating oil and lumber. The convenience yield becomes very large when inventories become small. This prevents stock-outs from occurring.

6.2 The equilibrium approach

The second general approach used in the literature to model forward prices is based on equilibrium considerations. Examples of this approach includes Keynes(1930), Hicks(1939), Cootner (1960), Richard and Sundaresan (1981), Hirshleifer (1988, 1990), Routledge et al (2000), Bessembinder and Lemmon (2002) and many more. Most of these focus on the relationship between the forward price and the expected spot price. In particular, this literature has traditionally focused on what is termed the forward premium, and as a consequence this approach is also known as the theory of risk premium. Usually the forward premium is defined as the difference between the forward price and the expected spot price. In the literature, the forward premium represents the equilibrium compensation for bearing the price and/or demand risk for the underlying commodity.

A speculator with a long position hopes that the price of the asset will be above the futures price at maturity. Suppose the speculator puts the present value of the futures price into a risk free investment at time t while simultaneously taking a long futures position. The cash flows to the speculator are

Time t: $-F_{t,T} e^{-r(T-t)}$

Time T: S_T

Where S_T is the value of the asset at time T. The present value of the investment is

$$-F_{t,T}e^{-r(T-t)} + E[S_T]e^{-k(T-t)}$$

where k is the discount rate appropriate for the investment and E denotes the expected value. Assuming that all investment opportunities in securities markets have zero net present value gives:

$$F_{t,T} = E[S_T]e^{(r-k)(T-t)}$$

The difference between k and r is the risk premium. A typical equilibrium approach to commodity pricing is a model or theory that calculate or explain the size of k. Two well- known equilibrium asset- pricing models are CAPM and APT. However, as explained by Maudal and Solum (2003), they do not relate very well to electricity markets, and therefore we choose not to elaborate more on these theories. Other well-known models include the classic hedging- pressure theory, suggested by Keynes, Hicks and others. This model argues that the risk premium component of prices is dependent on the risk preferences of hedgers and speculators. They argued that in bacwardation, hedgers in commodity markets are producers who will sell their wares forward at lower prices than those expected in spot markets, paying en insurance premium for reducing risk. In this situation the forward price will be lower than the expected spot price.

$$F_{t,T} < E[S_T]$$

This happens, as speculators require a premium or compensation for taking risk, implying that k > r, when following (3.3). The hedgers are prepared to take positions reducing their expected payoff, since they at the same time are reducing their risk. This situation, where the futures price is lower than the expected spot price is called normal backwardation.

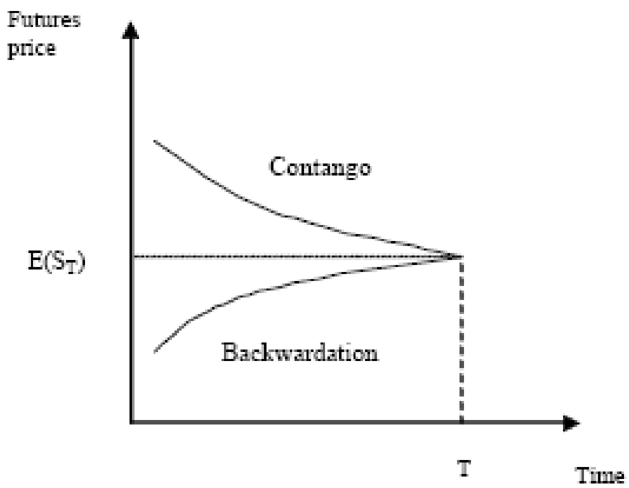
The opposite situation occur when buyers wish to hedge their exposure and pay a premium on futures prices to speculators which take their risk:
If the hedgers hold long positions and the speculators hold short positions, the futures price will be above the expected spot price

$$F_{t,T} > E[S_T]$$

This situation is known as contango. According to (3.3) this should happen if k < r.

Some authors refer to the terms contango and backwardation somewhat different from that above. E.g. Pilipovic (1998) and McDonald (2003) say the market is in contango when the forward curve is upward sloping and in backwardation when the forward curve is downward sloping. This is what Hull (2000) characterizes as normal market and inverted market respectively. We hereby emphasis that when we refer to contango and backwardation, we follow the framework given by (3.6) and (3.5). The following figure is included for clarifying and visual purposes [Copeland & Weston, 1988]

Figure 6.2.1: The definition of backwardation and contango in the forward market (Source:)



Various literatures have argued for different hypothesis concerning the sign and size of the risk premiums in commodity markets followed by empirical research. In the following chapters we will present some of this research and comment on how it relates to electricity markets.

6.3 Aspects from the literature on risk premium

As explained in the previous chapter the equilibrium futures pricing literature explains premium or bias in futures prices in relation to aggregate hedging pressure by producers and consumers. In summary, this literature implies that the forward premium should be fundamentally related to economic risks and the willingness of different market participants to bear this risk [Longstaff and Wang, 2002]. Keynes and Hicks proposed the theory of normal backwardation for commodity markets, arguing that producers take short positions in the futures market to hedge their initial long position in the commodity. Their supply of futures contracts, or hedging pressure, tends to drive down the futures price relative the expected value of the future spot price. More recent work in which producers also face quantity risks as well as price risk has shown that they might take long instead of short futures positions, arguing that producers will want to hedge their overall income risk by going long if quantity is relatively variable compared to price (elastic demand) and going short in the opposite case. So upward and downward bias in the future price depends on whether the aggregate hedging pressure by producers are long or short [Hirshleifer, 1990]. Another argument used to support the theory of normal backwardation is that consumers rather than producers are driven by the fixed costs of the futures market. The reasoning goes as follows. Many consumers relative to producers result in very small positions of consumers, and sufficiently small transaction costs will deter only consumers.

Empirical analyses from commodity markets have given some support for the theory of normal backwardation. However, the results are far from conclusive.
Fama & French (1987) employ univariate tests for expected premiums and find some evidence of positive returns from a long futures position in 19 of 21 commodities on a 1 to 3 monthshorizon. However, they stress the fact that the validity of the statistical tests employed are discussable. Chang (1985) also finds support for the theory of normal backwardation in wheat, corn and soybeans futures markets. In the case of corn and soybeans, Chang (1985) finds that the speculators were rewarded a risk premium for the bearing of risk rather than for their favourable forecasting ability, and emphasizes that the theory of backwardation is ideal for explaining this.

The kind of reasoning for backwardation as given by Hirshleifer (1990) is not valid for the Electricity markets, especially not on a short time horizon. First, demand for electricity has historically been viewed as inelastic in the case of small residential consumers [Wangensteen, 2001]. However, these are not participating in the futures market. Retailers and large electricity consumers do participate on the buyer side of the futures market and may appear very elastic to prices. Second, because retailers and large consumers constitute the demand side, transaction costs will not necessarily cause the demand side to deter the futures market. Hence the classic backwardation situation for many commodities does not have to occur in the German electricity market electricity market. We will elaborate further on equilibrium theory related to electricity markets in the next section, and what factors that influence the hedging pressure in these markets.

6.4 Futures pricing theory and electricity markets

Electricity has certain characteristics that make it differ from other commodities. Electricity can be considered as a flow commodity strongly characterized by its very limited storability and transportability. Both limits to the possibility of carrying electricity across time and space are crucial in explaining the behaviour of electricity spot and derivatives prices compared to other commodities [Lucia & Schwartz, 2002]. These limitations reduce arbitrage possibilities, which are based on links across time and space. This will affect the spot–futures relationship, thus the theory of storage or cost-of-carry models do not really apply for pricing power forwards [Bessembinder & Lemmon, 2002]. This inability for market players to arbitrage this non storable commodity may explain why evidence is strong for relatively sizable risk premiums in electricity markets [Mork 2004]. Hedgers are forced to use derivative markets to reduce risk rather than exercise a "buy and hold" strategy. For the same reason, there tend to exist longer maturity contracts in electricity markets than for other commodities.

Other special features in electricity markets, which adds to the complexity markets participants are facing when pricing risk are information asymmetries, regulatory risk and market power of some of the agents. In this context, as Newbery er al. (2004) emphasize, it would be unrealistic to assume that forward electricity prices are the best forecasts of future spot prices reflecting expectations on fundamental demand and supply conditions. We take the same perspective as Karakatsani and Bunn (2005), that equilibrium forward prices in the electricity markets are determined as a result of the demand and supply of hedges, which is a reflection of the relative risk aversion of market participants, the speculative positions and the perceived cost of risk as well as a function of the basic fundamental drivers of supply and demand for the physical commodity.

In the following sections of this chapter we present some of the recent theories and analysis on equilibrium forward prices for electricity and other commodities, and what factors that influence the hedging pressure over time. Then empirical evidence from deregulated electricity markets around the world are presented. Just as important as their quantitive results, are how they explain the existence of the forward premium, only this way we can get closer towards understanding the complex dynamics of electricity spot and forward prices. However, due that all this markets are still young, the empirical results can only be viewed as preliminary evidence.

Equilibrium pricing model introduced by Bessembinder and Lemmon

In the paper "Equilibrium Pricing and Optimal Hedging In Electricity Forward Markets" (), Bessembinder and Lemon present a equilibrium model of electricity spot and forward markets, that can be applied when prices are determined by industry participants concerned with both the mean and risk of their profits, rather than outside speculators. First they evaluate the power producers' and retailers' net demand for forward contracts, and use the results here to obtain closed form solutions for the equilibrium forward power price and optimal forward positions. The implications of the model are then illustrated through a set of simulations showing that the equilibrium forward price can be greater or less than expected delivery date spot price, depending on expected market demand and demand volatility. More specifically their model states that the forward risk premium is a function of the difference between two covariance terms that can be approximated as the variance and skewness of spot prices, respectively. When expected power demand is low and demand variability is modest (as might be expected during the temperate months of spring and fall) there is little skewness in spot prices, and power retailers' desire to hedge their revenues leads to a downward bias in equilibrium forward prices. In contrast, when expected demand is high relative to capacity or demand is more variable, the distribution of spot power prices becomes positively skewed. Short forward positions incur large losses if upward spikes in spot prices occur, and the equilibrium forward price is therefore bid up to compensate skewness in the spot price distribution.

In the U.S power demand is largest and most variable in the summer. The model therefore predicts an upwards bias (contango) in the forward power prices for summer delievery.

Their model makes the following testable hypothesis regarding the forward premium in power prices:

the equililbrium forward premium decreases in the anticipated variance of wholesale prices, ceteris paribus.

the equilibrium forward premium increases in the anticipated skewness of wholesale prices, ceteris paribus.

the equilibrium forward premium is convex, initially decreasing and then increasing, in the variability of power demand, ceteris paribus.

the equilibrium forward premium increases in expected power demand, ceteris paribus.

Dong and Liu

In "Equilibrium Forward Contracts on Nonstorable Commodities in the Presence of Market Power", Long and Diu model the forward contract negotiation on a non-storable commodity between a supplier and a manufacturer by a Nash bargaining game, and derive its unique equilibrium in closed form. In addition to the forward contract, they can also trade in the spot market for the commodity. As in the Bessembinder and Lemmon paper, both the supplier and the manufacturer are risk sensitive, but opposed to Bessembinder and Lemmon assuming that both retailers and producers are price takers, Liu and Dong assumes that both the manufacturer and supplier have significant market power in the power market because of the "limited number of market participant phenomena" in the world wide electricity markets. The main argument for assuming risk- aversion being that decision makers are indeed risk sensitive in decision setting where the firm's risk is not diversifiable and the markets are imperfect.

They find that in contrast to a forward contract on a storable commodity, the forward price on a non- storeable commodity can be non- monotonic in the spot price; the equilibrium forward price can be lower or higher than the expected spot price, depending on the supplier's just in time (JIT) capability and market power; both the equilibrium forward price volatility and the forward quantity volatility decrease as the time to maturity increases. They explain this non- monotonicity by two offsetting effects, the strengthening of the speculation benefit and the weakening of the hedging benefit as, as the spot price increases. They also find that the forward price is lower than the expected spot price for winter, spring and fall in , and explain this by the supplier's low capacity reservation cost (i.e., strong JIT capability). In particular, the supplier's weak market power drives the equilibrium forward price close to his capacity reservation cost, which is lower than the expected spot price. In summer, however, the supplier has strong market power and a high capacity reservation cost, and they find that the forward price is higher than the expected spot price.

As we see this modell has many implications as the Bessembinder and Lemmon model, predicting time varying premiums for the electricity markets, with a contango situation for periods with low demand and prices, and backwardation for periods of low demand and prices.

Karakatasani and Bunn 2004

In this paper Karakatasani and Bunn argue that the pricing risk in forward electricity trading is a complex issue confounded by the non- storability of the commodity, market power of some of the agents (Borenstein et. Al. 2002), information asymmetries and regulatory risk. In this context it would be unrealistic to assume what forward prices reflect are the best forecast of future spot prices reflecting expectations on fundamental demand and supply conditions. Instead, what forward prices reflect are demand and supply of hedges, which is a reflection of the relative risk aversion of participants, the speculative positions and the perceived cost of risk as well as a function of the basic fundamental drivers of supply and demand of the physical demand for the physical commodity.

Instead of proposing a new equilibrium model, they point out several important factors which impact on the hedging pressure of different electricity markets. One of the questions they address is whether the sign of the forward premium can be reversed, and under which conditions it may occur. They try to uncover systematic patterns in the sign of the day ahead forward premium and clarify further its sensitivity different changes in the surroundings.

They present the following hypothesis on the forward premium

The sign of the premium changes sign during day depending on the diverse technological characteristics and market power potential of the operating plants, which imply diverse hedging incentives. More specifically, generators may receive or contribute a premium depending on whether they possesses the technical flexibility to bear suppliers' price and demand risk or instead, intend to hedge their own operational risks.
The forward premium may present a systematic and to some extent, expected component, reflecting for instance: i) market consensus for pricing systematic risks, such as technical, regulatory and trading (e.g illiquidity) risks, ii) persistent market manipulation and iii) persistent errors in agent predictive models due to non-transparent information.
in addition to perceived price and demand risks, captured by LW, the forward premium is likely to respond to strategic variables, such as the amount of capacity available, which is an index of security of supply but also prone to manipulation by generators.
The responses of forward premium t influential factors may be dynamic reflecting agent learning, which is substantial due to highly repetitive auctions or bilateral transactions, the adaptive market structure as well as regulatory interventions.
There is an interaction between spot and forward markets, as opposed to a one-directional causality, created by technical reasons as well as strategic incentives. It is plausible that the forward premium, which is induced by spot price volatility and skewness, influences subsequently the spot price by aggecting capacity scheduling decisions (e.g maintenance or hydro release)

6.5 Empirical results from electricity markets

The evidence for forward premiums are stronger in electricity markets, than for other commodity markets.

Bessembinder and Lemmon (2002) test whether data from PJM and CALPX are consistent with the broad implications of their model. They find that in each market the forward price is biased upward in the summer months, and that the bias is much smaller during the other seasons. This is consistent with the model prediction that high skewness in spot prices will lead to an upward bias in the forward price.

Longstaff & Wang (2002) have conducted an empirical analysis of electricity forward pricing
at the PJM market, USA, using a high-frequency data set of hourly spot and day-ahead
forward prices. They focus on how the electricity forward prices are related to expected spot prices, and test whether the forward premium, as economic theory suggests, is a compensation given to markets participants for bearing risk. L &W first test the sign of the forward premium, before examining how the premium relates to three of the fundamental economic risks present in the electricity markets (price uncertainty, quantity uncertainty and the risk of price spikes occurring as demand approaches system capacity), in order to test whether prices in electricity markets represent the outcome of a rational market clearing process.
Longstaff & Wang find significant risk premiums in electricity forward prices at PJM. These premiums vary systematically throughout the day and are directly related to all the economic risks mentioned above. L and W also regress the mean premium on the variance and skewness and measures of the spot price during the sample period, and find evidence supporting the hypothesis proposed by Bessembinder and Lemmon; that the risk of price spikes arising from unanticipated sudden increases in power demand can have significant effects on the size and even the sign of the premium.

Shawky, Marathe and Barrett (2003) find strong evidence for risk premiums in California- Oregon Border (COB)

In the Nordic power market, which is one of the most mature and efficient electricity markets in the world. Maudal and Solum (2003) find evidence of significant time-varying premiums. Supporting the broad implications of the model introduced by Bessembinder and Lemmon.
Mork (2004) draw some of the same conclusions for the Nordic market, and also find evidence of learning effects in the market, leading to increasing forward premiums after periods of extreme prices. Also, he find evidence of increasing premiums after the departure of speculators from the market, caused by the ENRON bankruptcy.

In a recent paper from the UK market, Karakatsani and Bunn (2005), comments on the sign and economic properties of day- ahead forward premium in the british electricity market after the reforms introduced in March 2001. They find that the following factors influence the magnitude and sign of the foreward premium:
Price risks; they find increasing sensitivity to the imbalance price risk following governmental interventions.
Capacity availability which is confounded by strategic behaviour. They find a decline of strategic impact on the magnitude of the forward premium, which can be interpreted as a sign of gradual market efficiency.
Trading inefficiencies
Aspects of market design
They also find diurnal reversals in the day ahead forward premiums, supporting the model presented by Bessembinder and Lemmon.

7 Risk and hedging

7.1 Market participants and risk

The participants can be risk neutral, risk averse or risk seeking. However, it is reasonable to
believe that most participants are risk averse as they would probably prefer a sure outcome to

an unsure outcome with the same expected value. Risk averse participants have concave
utility functions, which means that the marginal utility of income is decreasing. While a risk
neutral participant only considers expected income, a risk averse participant takes both
expected income and risk into consideration.

Even though most participants are expected to be risk averse, it's important to note that there exist different degrees of risk aversion. The fact that a company's utility is a non- linear function of income results in risk and risk analysis always having to be connected to the company's complete income and complete risk. The corporate management's evaluation of goals and strategy also entails an evaluation of the company's attitude towards risk. From such an analysis it is decided on which risk profile the
contract portfolio should have. A company with large risk factors beyond the purchase of
power will probably accept a lower level of risk in its contract portfolio than a company with
low risk beyond the purchase of power. The share of the budget used for power purchase will
also influence the risk acceptable for contracts.
In the financial community the portfolio management aims at investing in a combination of securities that jointly results in high-expected return while keeping the risk within the desired level. For the power market this means buying and selling contracts in order to ensure low purchasing price of power for the case of a consumer, and to ensure high selling price for the case of a producer, based on the chosen level of risk. Diversifying the investments among a number of different companies is a strategy for reducing risk in the financial community. A pure electric power company has not this opportunity to reduce its risk if it operates in the power industry exclusively. For consumers, the share of the total power consumption purchased at fixed prices and the share purchased at spot prices, tells something about their risk exposure.

7.2 The basis of the risk premium in the electricity market

The risk present in electricity markets have different sources. According to Wangensteen (2001), there are three main sources of risks in the Nordic electricity market, as we see it this is the same in the German electricity market. These are:

Market risk; - this is risk connected to price fluctuations som følge av changes in demand and supply. Included here are:

- Price risk

This is associated with the uncertainty connected to future spot prices.

- Volume risk

This is related to the future volume of power and is often caused by temperature dependent consumption.

- Counter party risk

This is the risk of the opposite party of the contract not being able to pay or deliver.

- Liquidity risk

This type of risk arises from the fact that some markets periodically experience low liquidity, which makes it more difficult to close or change positions at desired moments of time.

The volume risk and price risk is not totally independent, since the price tend to increase as the demand increases.

Strategic risk; closely linked to political decisions and covers changes in external conditions. Examples are changes in the energy laws, concessions, rules for power exchange, introduction of emission trading, interest rates and foreign currency

Technical risk. Technical risk relates to outages in production and distribution facilities.

In this paper we are only interested in the risk that are of significance for the market participants and their hedging decisions, because this is what affects the size of the forward premium. Obviously, the market risk is the most important in this context. In most cases the greatest risk is connected to the price risk. Bessembinder & Lemmon (2001) and Longstaff & Wang (2001) show that price risk is a major risk for both buyers and sellers of electricity. Longstaff & Wang (2001) point out that the complexity of the market makes it difficult to argue that the participants always take the same position in the term market, whether long or short. There can be considerable volume risk for power producers as demand varies with the temperature. The latter is also relevant for the retailers. In the short term, electricity demand can be fairly well forecasted, but deviations are almost certain to take place. A power retailer that contracts to buy power in the bilateral market may experience that demand turns out to be less than anticipated and will not be able to sell his contracted volume to end-users. If the spot price drops, which is likely to happen when demand is less than anticipated, the retailer will lose by selling his excess volume in the market. On the other hand, unexpected cold weather might force a retailer to buy more power in the spot market. Spikes in demand are very often associated with high spot prices [Knittel& Roberts, 2000].

In summary, both volume risk and price risk are important to market participants. Their profits are driven by the total cost or revenue associated with power which again is driven by the product of quantity (volume) and price. Participants can hedge price risk by entering into derivative contracts in the organised market, EEX, or in the bilateral market. These contracts only hedge the contractual volume.
Longstaff & Wang (2001) and Bessembinder & Lemmon (2001) also discuss a related source
of risk, the risk of total demand approaching or exceeding the physical limits of power generation. These extreme situations will cause extreme prices, also known as price spikes.

Quoting Longstaff & Wang (2001):
"The risk of price spikes as demand approaches system capacity is an extreme type of price risk which may have important implications for the relation between spot and forward prices in the PJM market."
The counter party risk can be perfectly hedged by entering standard contracts at EEX. For these kind of contracts EEX Clearing handles the counter party risk.
The liquidity risk is more severe for other electricity markets. Her noe om likviditeten I EEX, evt henvisning til andre steder vi kommenterer dette.
Fortsettelse om de andre risiko faktorene, tilknytt ny teori.

As a consequence of the significant level of risk in the electricity markets, producers, retailers and consumers have a demand for products for handling this risk. This includes an array of different products and methods. However we only focus on forward contracts in our thesis.

7.3 Different market participants and their hedging needs

We divide the electricity market's participants into producers, retailers and large electricity consumers. Even though some of the largest firms in the German electricity market, as explained in chapter …, entail business that relates to all three participant groups. In the following sections we describe the behavior of the market participants, and how they manage the risk omtalt in the previous chapter.

7.3.1 Producers

Here, we assume power producers to sell power in the wholesale market and to large electricity consumers.
According to Bessembinder and Lemmon (2002) the ex-post profit of producer i, π_i, is given by

$$\pi_{Pi} = P_W Q_{Pi}^W + P_F Q_{Pi}^F - F - \frac{a}{c}(Q_{Pi})^c$$

The explanation for the variables are given in chapter….. In the German market the futures and forward contracts are financial instruments, implying that the profit is given by

$$\pi_{Pi} = P_W Q_{Pi}^W + (P_F - P_W) Q_{Pi}^F - F - \frac{a}{c}(Q_{Pi})^c$$

Q^F_{Pi} must then be interpreted as the volume hedged in the forward market for this time step. We here exclude the possibility of speculating in the forward market. $Q^F_{Pi} > 0$ indicates a net short position for the producer and $Q^F_{Pi} < 0$ indicates a long position. Here Q^W_{Pi} is the volume sold in the spot market and equals the physical production

The producers in the German market are mainly thermal producers, and do not the opportunity to store electricity in the same way as a hydro power producers. In consequence, they are not as flexible in production, and this increases their need for hedging. However, as showed in …. Spotprices in Germany are recognized by skewness during summer and winter, which indicates that the probability for high extreme prices is higher than the probability for low ones. A critical aspect in the interpretation of how this influences the hedging pressure is the asymmetric positions of generators and suppliers towards this risk, induced by technical issues and market design [Karaktasani and Bunn, 2004]. Producers (generators) has the ability to profit from spot price fluctuations by exploiting various parameters, such as plant portfolio, degree of horizontal integration, technical flexibility to adjust production in short-time scales and potential for market power. This certainly holds for the German power market where four large vertically and horizontally integrated companies owning a diversified plant portfolio controls the market.

Engaging into forward contracts reduces the sensitivity of generators' profits, but may also create incentives for them to induce volatility in the spot market to impose hedging pressure and in this way extract higher forward premiums [Batstone, 2001].

But more profit from price peaks etc

A logical assumption would be that producers in pre dominantly hedge their risk by excercising a long strategy in the forward market.

7.3.2 The demand side

Retailers and large industrial power consumers dominate the demand side of the German power market. The demand side secures their obligations pre- dominantly through innta long positions in the forward market.

In the PJM market, retailers buy the difference between realized retail demand and previous forward purchases. The ex-post profits for each retailer j is given by [Bessembinder & Lemmon, 2002]

$$\pi_{Rj} = P_R Q_{Rj} + P_F Q_{Rj}^F - P_W (Q_{Rj} + Q_{Rj}^F)$$

where P_R is the fixed retail price and Q_{Rj}^F is the quantity sold forward by retailer j (purchased if negative). For the German market with pure financial futures and forward contracts this should be rewritten as

$$\pi_{Rj} = P_R Q_{Rj} + (P_F - P_W) Q_{Rj}^F - P_W Q_{Rj}$$

The first expression on the right side indicates the income. The second term indicates the income or cost from holding a financial position, while the third term indicates the cost of purchasing power in the spot market. From conversations with participants in the market, we have the impression that the retailers operate with a quite short time horizon in their hedging decisions. The norm seems to be to secure their volume only weeks before delivery. Some of the explanation of this is that the sluttbrukerne can change retailer on a short notice, which introduces a considerable volume risk for the retailers. As mentioned in the previous section, producers are prone to profit from extreme prices both due to the asymmetric positions of producers and suppliers and the possibility of extracting higher forward premiums. In contrast, retailers are exposed to risks implied by spot price and retail demand. The latter is almost inelastic to price in the short- term and, as opposed to aggregated demand, it is very complex to predict. This effect is strengthened during the winter in Germany because end user consumption is believed to be the dominant reason for extreme prices in EEX during winter- time. (skriv I priser om hva som er den dominerende grunnen for høye priser I ulike årstider)

Large electricity consumers include all kinds of industry, but power demanding companies operating in the ferroalloy industry, chemistry industry and in manufacture of paper are among the largest industrial consumers in Germany, as mentioned in chapter…. We can write the cost of purchasing power for such a firm as the sum of energy bought spot corrected for gains or losses in the forward market

$$Cost_{Li} = P_W Q_{Li}^W + P^F Q_{Li}^F$$

7.3.3 Speculators

The volatile prices in the electricity market are the reason for the hedging performed by the market participants mentioned in the previous sections. However, this is what attracts the speculators to the market. The considerable volatility and presence of risk premiums rises the possibilities for earning big profits for risk seeking participants. This, in combination with the fact that the forward contracts traded at EEX are financial contracts, not connected to physical delievery attract speculators to the market.

7.4 Hypotheses about the risk premium in the German Power Market

Based on the previous chapters, we state the following hypotheses for the risk premium in the German power market.

1. The short- term forward contracts are on average contango.
2. The forward market experience variations in the short-term premium, with contango in the cold season and lower premiums in the spring season and autumn months.
3. The forward market is in backwardiation in the longer term contracts.
4. The extreme prices during the summer of 2003 lead to a structural change in the risk premium, due to increased hedging by consumers (retailers).

Here, we define short term as month contracts, and longer term as quarter and year contracts. It also refers to the time horizon until expiration date that we choose to analyze the forward premium. We choose a longer analyzing period on the quarter and year contracts because these are naturally traded for a longer period before expiration than the month contracts.

7.4.1 Explanation for hypothesis 1

We will here briefly summarize the indications for an average contango situation in the short- term premium.
First, the conditions leading to a backwardation situation for certain commodities are often the opposite of the conditions that prevail in the German power market, as explained in chapter …
Our description of the hedging needs for the different types of producers and retailers have shown differences in the ability to benefit from the variability in prices and demand.
As we know the German power market is dominated by thermal production. Thermal producers are much less flexible due to constraints regarding regulation of output and costs, compares to hydropower producers. For this reason, the thermal base load producers will have a larger position of their expected production hedged in the forward market. The marginal production costs of thermal producers are convex and exponentially increasing with production. In this respect, profits for thermal producers change more closely with spot prices than for hydropower producers. This should contribute to increased demand for long hedges and lower forward prices in Germany compared to for example Norway.

On the other hand, retailers and large consumers are unable to store power in any sense. The composition of the retailers' end- users will also affect the retailers' demand for hedging. According to the work of Maudal and Solum (2003), retailers with a fixed price will hedge a large part of his expected retailer quantity. Also retailers with a variable price structure will hedge significant parts of its expected retail quantity, while retailers that offer a spot price with a mark- up will only take positions in the forward market if he can find a significant premium in the market. Traditionally, the use of a variable price structure or a fixed price structure has been widespread. This indicates a high demand of hedging from the retailers.

Third, the retailers' short horizon in the futures market indicates an increased demand for a long position in the weeks before maturity. This means that the pressure is driven towards a contango situation in the weeks before maturity.
Also the possibility for and history of market power in the German power market in combination with a history of highly unstable unpredictable prices add to the retailers and large power consumers demand for short hedges.
Altogether this would lead to an unbalanced hedging pressure, indicating a contango situation. If all the participants in the market had been risk neutral, and such a situation was expected, they should optimally take long positions in the futures market to exploit this fact. However, we believe the participants are too risk averse to exploit the full potential of this and thereby this effect is not strong enough to balance the hedging pressure, giving an equilibrium contango situation.

7.4.2 Explanation for hypothesis 2

In our discussion we described how the need for hedges is stronger for retailers than for the producers. This is particularly severe in the cold seasons when demand is high and price spikes potentially can occur. The effect of price spikes can be measured by the skewness of the distribution of prices. As we see from our calculations in chapter… this is higher during summer and winter months than for spring and autumn in Germany. The reasons for this are explained in the price analyses. As we explained earlier extreme prices are less important for power producers when deciding hedging positions. We find positive sign of the skewness estimates for the entire price series in the German market; this reveals that high extreme values are more probable than low extreme values. This positive skewness of the price distribution is beneficial to power producers, and their short hedging demand due to this phenomenon is decreasing. However, as a result of the negative skewness for spring and autumn months it is reasonable to believe that the covariation between these producers' "but- for-hedging" revenues and spot price is strengthening (see Bessembinder and Lemmon (2002) for explanation). This again optimally induces producers to take larger short positions for these periods. At the same time of year demand is decreasing, making especially retailers reduce their long positions. We don't think it is reasonable to believe the effect of this situation to be strong enough to shift the hedging pressure to a situation of backwardation, because of the information asymmetries present in the German market. We do, however, expect a significant decrease in risk preium for the months of negative skewness. As we see from the results from our skewness calculations, the peak prices are more skewed than base prices, and we would therefore expect a overall higher retail hedging pressure for peak load prices, resulting in higher overall risk premiums. However, it should at least decrease the premium substantially. If participants expect the seasonal variations, they should optimally take positions in the futures market to exploit this fact. However, we believe the participants are too risk averse to exploit the full potential of this and thereby this effect is not strong enough to balance the hedging pressure.

7.4.3 Explanation for hypothesis 3

As mentioned, information given by the participants indicates that retailers have a quite short horizon in their hedging. Industrial participants like companies in the ferroalloy industry , chemistry industry and paper manufacturers will normally have a longer time horizon when it comes to hedging. Our impression is that large producers will probably have a quite long hedging position, this is verified through conversation with Norsk Hydro ASA, a major player in the German aluminum industry. In the bilateral market 5- 10- and 20-years contracts are traded.

Producers have stronger incentives to hedge on a long time horizon than retailers. Retailers change their fixed retail price on a regular basis and are thus able to transfer costs to their customers in the long run. This is probably the reason why producers have strong resources dealing with analysis. Being able to predict prices in the long term well is also important for valuing producers' long term investments and to make decisions on whether to invest or not.

Also, Syvertsen (2001) draws on the investment perspective of power assets and claims that forward prices must be lower than expected spot prices when using a discount rate higher than the risk free rate. Investments in power assets are mostly long-term investments and to the extent of the validity of Syvertsen's theory, we would expect to observe this in the long term.

7.4.4 Explanation for hypothesis 1

In a young market such as EEX, events may occur which result in changes in the behaviour of the market participants. Bessembinder and Lemmon (2002) discuss the learning effect that may arise in new markets. With the highly repetitive auctions present in electricity markets, naturally agents will develop their trading and hedging strategies as their experience and knowledge increases. Such a learning effect may have occurred after the summer of 2003. As mentioned earlier during the summer of 2003, several factors contributed to extreme prices during the period from June until August. Prices and volatilities shot up to record levels in June 2003. These extreme prices followed a period of highly volatile prices in the German power market, which may contribute to the learning effect. We propose the hypothesis that this incident increased hedging from the demand side and caused a shift in risk premiums.

8 Empirical Analysis

8.1 Estimating the risk premium

In order to estimate the forward premiums and test these hypotheses, we use the same framework as Mork (2004). The future premium is defined as the percentage difference between the futures (or forwards) price at time t and the expected spot price at time T, or

$$P_{t,T} = \frac{F_{t,T} - E(S_T)}{F_{t,T}}$$

Where $T - t$ is the number of trading days to maturity. Thus the premium will be positive if consumers hedge more than producers, and negative if producers hedge more than consumers. As mentioned earlier it is impossible to observe the expected spot price directly, Mork solves this estimating the forward premium by differencing the futures or forward price with the realized spot system price in the delivery period:

$$\hat{P}_{t,T} = \frac{F_{t,T} - \overline{S}_T}{F_{t,T}}$$

The difference $\hat{P}_{t,T} - P_{t,T}$ is then a pure expectations error, which can be assumed to be uncorrelated with information at time t under rational expectations. We estimated premiums for the period 2002- April 2005, because this is the period for which we had complete data. However, the introduction of emission trading starting February 2005 put considerable stress to the German prices. This also affected the forward premiums a great deal, and given the limited data available they would have very big impact on the statistical analysis. We therefore leave the months from February to April 2005 out of our estimations. Due to the very limited period for which historical data are available, the uncertainty about the results of the statistical tests is considerable. However, we still see our results important as an indication of the size of the risk premium in Germany, and what trends the further development of the market is taking.

8.2 Estimation of the short- term risk premium

Here we concentrate on the month contracts, which is the one of the exchange- traded contracts on EEX with the shortest delivery period. The premium is estimated for month contracts in the period January 2002 to April 2005, because this is the period we have complete data for month contracts. We have chosen to estimate the premium for a 100 day period, both to see how the premium develops over time and to increase the statistical significance of our data.

As explained in the hypothesis chapter we expect a positive premium on average for month forward contracts because of the retail hedging pressure. In the following statistical analysis we leave the months from February 2005 until April 2005 out our analysis of reasons explained earlier. We also perform an additional analysis leaving out the data from the summer of 2003 (June- August). This is based on the same argument as leaving out the numbers from the emission trading. As explained in the price analysis several coinciding hendelser this summer lead to extreme prices over a long period, this lead to forward premiums in this period not representative for the norm in the German power market.

In the following statistical analysis we first estimate premiums for base load contracts, thereafter premiums on peakload contracts are estimated. In order to see how the forward premiums evolved over time, closing in on maturity date premiums for contracts traded 1, 30, 60 and 90 days before maturity are estimated.

8.2.1 Baseload contracts

The printout from Minitab of the descriptive statistics for base load month contracts is given below:

Descriptive Statistics: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

Variable	N	N*	Mean	SE Mean	TrMean	StDev	Median
Prem 1 d	37	0	0,0362	0,0241	0,0400	0,1467	0,0464
Prem 30 d	37	0	0,0269	0,0327	0,0317	0,1988	0,0547
Prem 60 d	37	0	0,00980	0,0332	0,0222	0,2018	0,0267
Prem 90 d	37	0	-0,0139	0,0325	0,000455	0,1977	0,0154

We observe that both the mean are positive for all variables except the 90 day premium. However, the median is positive for all variables. A 5% trimmed mean is calculated. Minitab removes the smallest 5 % and the largest 5 % of the values (rounded to the nearest integer), and the averages the remaining values. The trimmed mean is also positive. This indicate a mean positive risk premium i.e. contango.
For the 1, 30, 60 and 90- day risk premium a two sided hypothesis test is given by

$H_0 : \mathrm{Prem} = 0$ vs $H_1 : \mathrm{Prem} \neq 0$

was performed. The printout from Minitab is given below:

One-Sample T: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

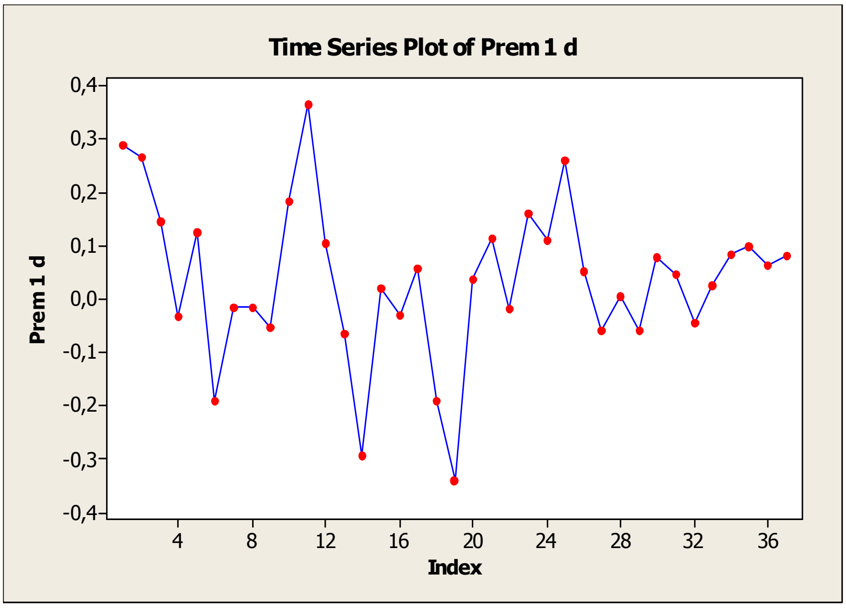
```
Test of mu = 0 vs not = 0

Variable    N       Mean     StDev   SE Mean      T      P
Prem 1 d   37   0,036152  0,146692  0,024116   1,50  0,143
Prem 30 d  37   0,026878  0,198847  0,032690   0,82  0,416
Prem 60 d  37   0,009802  0,201792  0,033174   0,30  0,769
Prem 90 d  37  -0,013948  0,197745  0,032509  -0,43  0,670
```

As we see, H_0 is not rejected for the base load contracts with 1, 30, 60 and 90- days to maturity, with p- values of 0,143, 0,416, 0,769, and 0,670 respectively.

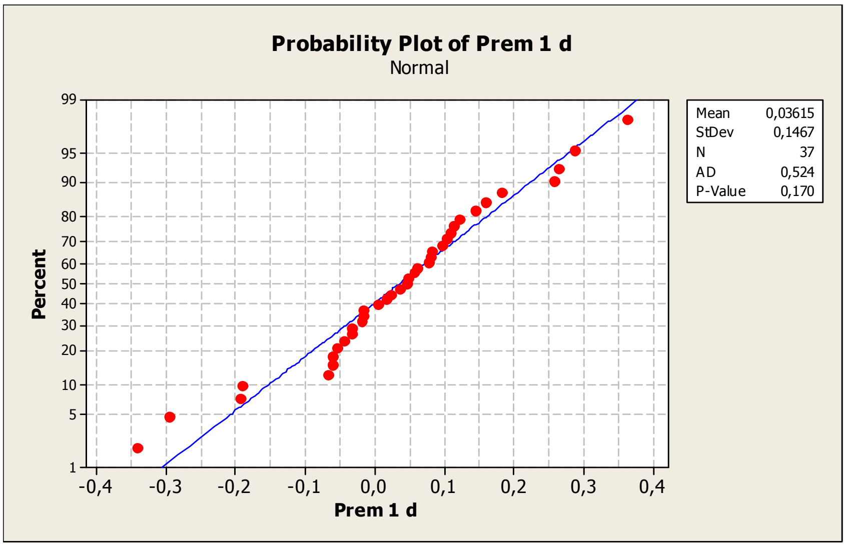
To justify the use of t- tests we have to verify that the data are normally distributed and random. We inspect whether this is true by performing a time series plot and a normality test.

Figure 8.2.1: time- series plot of the 1-day premium for month base load contracts.



By inspection the data seem to be random, but there might be a seasonal component. A seasonal component would be in line with our hypothesis. The time- series graphs for the 30, 60 and 90- day premium for base load contracts show the same randomness. This indicate that the use of t- test is valid for this data set.

Figure 8.2.2: normal probability plot for the 1-day premium for month base load contracts.



We observe fatter tails than what would be expected from the normal distribution. Anderson-Darling normality test is used to determine if data follow a normal distribution. If the p-value is lower than the pre-determined level of significance, the data do not follow a normal distribution. With a 95% significance level the P- value of 0,17 is well within swhat is needed to assume a normal distribution. The P- values from the 30, 60 and 90- day Anderson- Darling test for normality was 0,559, 0,090

and 0,224 respectively, which indicates that the assumption of normality holds for all distributions.
According to the central limit theorem you can do a t- sample test and have increasing confidence in the result as the number of observations increases. We only have 37 observations, which is a small number. Also, we are not certain about the randomness of our distributions; we will therefore try to see our results from another point of view.
Non- parametric statistics can be applied when the distribution is not normally distributed. The signed- rank test utilizes both the sign and the magnitude of the observations. For this test to be valid, the observations should be approximately symmetric [Walpole et al, 1998]. We test whether this assumption holds for our sample by performing descriptive statistics. The distribution is quite symmetric, with a skewness of –0,33. For the 30, 60, and 90 day premiums The skewness was –044, -0,98 and –1,05 respectively. In it important to stress that our number of data points is on the limit of what is needed to be able to draw valid conclusions. As rule of thumb (according to the help function of Minitab), you should have at least 25 to 30 data points. Interpreting a plot with too few data points may lead to incorrect conclusions.

The results from the signed rank test on the data are given below:

Wilcoxon Signed Rank Test: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

```
Test of median = 0,000000 versus median not = 0,000000

                  N
                 for   Wilcoxon
             N  Test  Statistic      P  Estimated Median
Prem 1 d    37    37      474,0  0,066           0,03922
Prem 30 d   37    37      424,0  0,277           0,03544
Prem 60 d   37    37      409,0  0,390           0,02027
Prem 90 d   37    37      351,0  1,000       -0,00009785
```

The p- values are all above 0,05, and H_0 is not rejected on a 95% level of significance. This does not support our hypothesis. However all the medians except the one for the 90- day premium are positive, which gives some support for our hypothesis of a contango situation for the short term premium.

We then perform the same statistical analysis on the data excluding the premiums from the summer of 2003, because as argued earlier data from this period could introduce some disturbance in our estimations. The printout of the descriptive data from Minitab is given below:

Descriptive Statistics: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

Variable	N	N*	Mean	SE Mean	TrMean	StDev	Median
Prem 1 d	34	0	0,0539	0,0225	0,0555	0,1315	0,0543
Prem 30 d	34	0	0,0601	0,0285	0,0587	0,1660	0,0580
Prem 60 d	34	0	0,0494	0,0258	0,0474	0,1502	0,0578
Prem 90 d	34	0	0,0252	0,0250	0,0256	0,1456	0,0332

We observe that the mean and the median are positive for all time intervals. The trimmed mean is also positive, indicating positive risk premiums. Compared to the descriptive data for the entire period, including the summer of 2003, we see a distinct increase of the mean risk premium for all the variables.

We then perform the same hypothesis test on these data. The printout from Minitab is given below:

One-Sample T: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

Test of mu = 0 vs not = 0

Variable	N	Mean	StDev	SE Mean	95% CI	T	P
Prem 1 d	34	0,053926	0,131454	0,022544	(0,008060; 0,099793)	2,39	0,023
Prem 30 d	34	0,060089	0,166006	0,028470	(0,002167; 0,118011)	2,11	0,042
Prem 60 d	34	0,049356	0,150159	0,025752	(-0,003037; 0,101749)	1,92	0,064
Prem 90 d	34	0,025223	0,145613	0,024972	(-0,025584; 0,076030)	1,01	0,320

H_0 is now rejected at a 5% significance level for the base load contracts with 1 and 30- days to maturity, with p- values of 0,023 and 0,042 respectively. However, H_0 is not rejected for the contracts with 30 and 60 days to maturity, with p- values of 0,064 and 0,320.

The tests for normality for this sample gave better results for the Andereson- Darling normality test than for the distribution from the entire period. This indicates validity for the normality assumption, and supports the use of t- tests.

We also performed a signed rank test for this distribution, to gain additional support for the
results from the t- test. The results from Minitab are given below:

Wilcoxon Signed Rank Test: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

Test of median = 0,000000 versus median not = 0,000000

	N	N for Test	Wilcoxon Statistic	P	Estimated Median

Prem 1 d	34	34	441,0	0,014	0,04965
Prem 30 d	34	34	414,0	0,047	0,05803
Prem 60 d	34	34	407,0	0,062	0,05037
Prem 90 d	34	34	351,0	0,365	0,02740

The p- values are below 5% for the 1 and 90- day premium, and 0,05803 and 0,05037 for the to others. The medians are positive and support the results from the t- test, giving an on average positive premium for the month base load contracts in this sample.

8.2.2 Peak contracts

In this section we perform the same analysis on peak load data as performed on the base load contracts. Entire period descriptive statistics are given below:

Descriptive Statistics: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

Variable	N	N*	Mean	SE Mean	TrMean	StDev	Median
Prem 1 d	37	0	0,0639	0,0295	0,0693	0,1796	0,0804
Prem 30 d	37	0	0,0635	0,0397	0,0733	0,2415	0,1186
Prem 60 d	37	0	0,0445	0,0418	0,0587	0,2541	0,1190
Prem 90 d	37	0	0,0238	0,0411	0,0406	0,2501	0,0866

We observe that the mean, median and trimmed mean are positive for all the time intervals, indicating mean positive risk premiums i.e. contango. Compared to the base load premiums are substantially bigger. (skewness and kurt)

For the 1, 30, 60 and 90- day risk premium a two sided hypothesis test is given by

$$H_0 : Prem = 0 \text{ vs } H_1 : Prem \neq 0$$

was performed. The printout from Minitab is given below:

One-Sample T: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

Test of mu = 0 vs not = 0

Variable	N	Mean	StDev	SE Mean	95% CI	T	P
Prem 1 d	37	0,063876	0,179624	0,029530	(0,003986; 0,123766)	2,16	0,037
Prem 30 d	37	0,063459	0,241455	0,039695	(-0,017046; 0,143964)	1,60	0,119
Prem 60 d	37	0,044508	0,254085	0,041771	(-0,040208; 0,129224)	1,07	0,294
Prem 90 d	37	0,023795	0,250095	0,041115	(-0,059590; 0,107181)	0,58	0,566

H_0 is only rejected for the 1 day premium, with a p- value of 0,037. For the 30, 60 and 90- day premium H_0 is not rejected with p- values of 0,119, 0,294 and 0,566 respectively. However we notice lower p- values than for the base load contracts in the same analysis period.

To validate the use of t- test, tests of normality is performed. The results are given in the appendix…. The Anderson- Darling normality test gives p- values of 0,066, 0,055, 0,006 and 0,013 for the 1, 30, 60 and 90- day premium respectively. At a significance level of 95%, normality is rejected for the 60 and 90- day premium, and the results from the t- test for these samples can be questioned. We perform a signed rank test to gain additional insight. Results from Minitab are given below:

Wilcoxon Signed Rank Test: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

```
Test of median = 0,000000 versus median not = 0,000000

                 N
                for   Wilcoxon         Estimated
           N   Test  Statistic      P     Median
Prem 1 d   37    37      515,0  0,014    0,07616
Prem 30 d  37    37      468,0  0,080    0,08972
Prem 60 d  37    37      448,0  0,148    0,07401
Prem 90 d  37    37      412,0  0,365    0,04444
```

H_0 is only rejected for the 1 day premium, with a p- value of 0,014. For the 30, 60 and 90- day premium H_0 is not rejected with p- values of 0,080, 0,148 and 0,365 respectively.

As for the base load contracts we perform the same analysis, excluding the premiums for the summer of 2003. The printout of Minitab is given below:

Descriptive Statistics: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

```
Variable    N  N*    Mean  SE Mean  TrMean   StDev  Median
Prem 1 d   34   0  0,0853   0,0276  0,0908  0,1611  0,0812
Prem 30 d  34   0  0,1035   0,0345  0,1081  0,2011  0,1304
Prem 60 d  34   0  0,0930   0,0336  0,0978  0,1959  0,1242
Prem 90 d  34   0  0,0710   0,0336  0,0769  0,1961  0,1180
```

We observe that the mean, median and trimmed mean are positive for all the time intervals, indicating mean positive risk premiums i.e. contango.

The same t- test performed on this data gives the following results from Minitab:

One-Sample T: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

```
Test of mu = 0 vs not = 0


Variable    N      Mean     StDev   SE Mean          95% CI              T      P
Prem 1 d   34  0,085332  0,161125  0,027633  (0,029113; 0,141552)  3,09  0,004
Prem 30 d  34  0,103504  0,201100  0,034488  (0,033337; 0,173671)  3,00  0,005
Prem 60 d  34  0,092987  0,195903  0,033597  (0,024633; 0,161341)  2,77  0,009
Prem 90 d  34  0,070951  0,196066  0,033625  (0,002541; 0,139362)  2,11  0,043
```

H_0 is now rejected at a 5% significance level for all the peak load contracts with 1, 30, 60 and 90 days to maturity, with p- values of 0,004, 0,005, 0,004 and 0,043 respectively.

Also the normality test shows better results for this distribution, supporting the results from the t- test. However, there are still some signs of non- normality, so we perform the signed- rank test to gain additional insight. A signed rank test on the same sample gives the following results:

Wilcoxon Signed Rank Test: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d

```
Test of median = 0,000000 versus median not = 0,000000

                 N
               for   Wilcoxon          Estimated
            N  Test  Statistic       P    Median
Prem 1 d   34    34      476,0   0,002   0,08801
Prem 30 d  34    34      456,0   0,007    0,1144
Prem 60 d  34    34      445,0   0,012    0,1119
Prem 90 d  34    34      411,0   0,053   0,08679
```

The p- values are well under 0,5 for all but the 90- day premium, where it is 0,053. H_0 is rejected on a 95% level of significance for the 1, 30, and 60 day risk premium. The p- value for the 90- day premium is also very close to rejecting H_0. This supports our hypothesis of contango situation for the short- term peak- load contracts.

8.3 *Estimation of the seasonal variation of the short term- premium*

A very common method used testing population means is ANOVA (Analysis of variance). In the following section we will use this method to test whether there are significantly differences between the mean risk premiums from month to month, both for peak and base load contracts. The test is performed of the pooled distribution containing all the observations in the 1, 30, 60 and 90- day premium distributions. This is done to increase the statistical significance of our very limited data.

The ANOVA tests the hypothesis

$H_0: RP_{Jan} = RP_{Feb} = ... = RP_{Dec}$ vs. H_1: At least two different from each other.

Where RP is the abbreviation for risk premium. First we test the Hypothesis on the Base load contract samples, then we test peal load samples.

8.3.1 Base contracts

Part of the printout of Minitab is given below:

One-way ANOVA: January; February; March; April; May; June; July; august; ...

Source	DF	SS	MS	F	P
Factor	11	1,7677	0,1607	6,51	0,000
Error	136	3,3578	0,0247		
Total	147	5,1255			

S = 0,1571   R-Sq = 34,49%   R-Sq(adj) = 29,19%

From the p- value of the ANOVA, we see that there is a 0,0 % chance of the mean being the same for all months. This strongly supports our hypothesis of time varying premiums. Next we perform a t- test to learn more about the size of the monthly premiums. A printout of the results from the t- test is given below

One-Sample T: January; February; March; April; May; June; July; august; ...

Test of mu = 0 vs not = 0

Variable	N	Mean	StDev	SE Mean	T	P
January	16	0,077325	0,173022	0,043255	1,79	0,094
February	12	0,084451	0,270480	0,078081	1,08	0,303
March	12	0,041068	0,111967	0,032322	1,27	0,230
April	12	0,041169	0,072766	0,021006	1,96	0,076
May	12	0,055912	0,071724	0,020705	2,70	0,021
June	12	-0,099354	0,150330	0,043397	-2,29	0,043
July	12	-0,208698	0,268905	0,077626	-2,69	0,021
august	12	-0,133742	0,158174	0,045661	-2,93	0,014
September	12	-0,052797	0,121055	0,034946	-1,51	0,159
October	12	0,026578	0,121393	0,035043	0,76	0,464
November	12	0,185520	0,121136	0,034969	5,31	0,000
December	12	0,138353	0,065641	0,018949	7,30	0,000

The p- values and confidence intervals indicate a positive premium for May, November and December. Whereas, they indicate negative negative premiums June, July and August. For the rest of the months the test is inconclusive on the sign of the premium. However indications are given through the sign and size of the mean.

As the data have shown deviations from the assumption of normal distribution, we also perform a non- parametric test. The Kruskal- Wallis test is a non-parametric test for the differences in value [Warpole et al., 1998], that we use to compare the different means of the different months. Using this test we presume that the populations have approximately the same standard deviations. From the ANOVA we have that the standard deviation range from 0,07 to 0,27, indicating that the specifications are not perfectly fulfilled. However, we still perform the test and the results are given below:

Kruskal-Wallis Test: Premium versus Month

Kruskal-Wallis Test on Premium

Month	N	Median	Ave Rank	Z
April	12	0,006909	75,8	0,11
August	12	-0,094487	37,8	-3,10
December	12	0,134672	110,1	3,00
February	12	0,196384	90,8	1,37
January	16	0,103646	87,9	1,32
July	12	-0,168687	37,2	-3,15
June	12	-0,124612	45,5	-2,44
March	12	0,026498	76,7	0,18
May	12	0,057192	82,6	0,68
November	12	0,189267	116,4	3,53

October	12	0,082691	76,8	0,20
September	12	-0,042663	52,2	-1,88
Overall	148		74,5	

H = 50,20 DF = 11 P = 0,000
H = 50,20 DF = 11 P = 0,000 (adjusted for ties)

Also this test give a p- value of 0,00, implying that the chance of observing 12 samples as separated as these, when the months in fact has the same median is 0,0% (given that the assumptions are fulfilled).

8.3.2 Peak contracts

The same tests are then performed on the month peak load samples. The results from the one- way ANOVA are given below:

One-way ANOVA: January; February; March; April; May; June; July; august; ...

Source	DF	SS	MS	F	P
Factor	11	3,0178	0,2743	7,68	0,000
Error	136	4,8586	0,0357		
Total	147	7,8764			

S = 0,1890   R-Sq = 38,31%   R-Sq(adj) = 33,33%

From the p- value we see that there is a 0,0% chance of the mean being the same for all the months. The t-test give the following results

One-Sample T: January; February; March; April; May; June; July; august; ...

Test of mu = 0 vs not = 0

Variable	N	Mean	StDev	SE Mean	T	P
January	16	0,108759	0,241279	0,060320	1,80	0,092
February	12	0,161622	0,281848	0,081362	1,99	0,072
March	12	0,119397	0,108396	0,031291	3,82	0,003
April	12	0,123431	0,110969	0,032034	3,85	0,003
May	12	0,064678	0,082125	0,023707	2,73	0,020
June	12	-0,194369	0,218111	0,062963	-3,09	0,010
July	12	-0,239744	0,315442	0,091060	-2,63	0,023
august	12	-0,096874	0,217612	0,062819	-1,54	0,151
September	12	0,013439	0,178328	0,051479	0,26	0,799
October	12	0,073202	0,120896	0,034900	2,10	0,060
November	12	0,242295	0,080378	0,023203	10,44	0,000
December	12	0,191130	0,068909	0,019892	9,61	0,000

The p- values and confidence intervals indicate a positive premium for March, April, May, November and December. Whereas, they indicate negative premiums June and July. For the rest of the months the test is inconclusive on the sign of the premium. However, indications are given through the sign and size of the mean. Although these results show considerable variations in the standard deviation, we still perform a Kruskal- Wallis test to gain additional insight. The results of this test is given below:

Kruskal-Wallis Test: Premium versus Month

Kruskal-Wallis Test on Premium

Month	N	Median	Ave Rank	Z
April	12	0,11848	83,8	0,78

August	12	-0,04964	44,9	-2,49
December	12	0,19326	106,4	2,69
February	12	0,25664	96,3	1,84
January	16	0,14078	85,9	1,13
July	12	-0,26208	35,3	-3,31
June	12	-0,33372	31,9	-3,59
March	12	0,14145	84,8	0,87
May	12	0,07392	67,7	-0,58
November	12	0,24763	117,5	3,62
October	12	0,09966	74,3	-0,01
September	12	0,03603	61,3	-1,11
Overall	148		74,5	

H = 53,29 DF = 11 P = 0,000

As from the test on the base load contracts, the p- value say that there is a 0,0% chance of the mean being the same for all the months.

8.4 Estimation of the long term risk premium

When estimating the long- term premium we estimate premiums for quarter, peak and base load contracts. We rule year contracts, which are also traded at EEX, out on the analysis because the available data are very limited and not sufficient for drawing any conclusions.

8.4.1 Base contracts

The printout from Minitab below shows the descriptive statistics for the base load contracts:

Descriptive Statistics: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d; Prem 120 d

Variable	N	N*	Mean	SE Mean	TrMean	StDev	Minimum	Q1
Prem 1 d	11	0	0,0196	0,0426	0,0126	0,1414	-0,1552	-0,1219
Prem 30 d	11	0	0,000611	0,0517	0,0119	0,1716	-0,3437	-0,1030
Prem 60 d	11	0	-0,0211	0,0528	-0,00176	0,1753	-0,3962	-0,1091
Prem 90 d	10	1	-0,0462	0,0579	-0,0285	0,1832	-0,4115	-0,1565
Prem 120 d	10	1	-0,0696	0,0528	-0,0574	0,1670	-0,3974	-0,1636

Variable	Median	Q3	Maximum
Prem 1 d	-0,00748	0,1446	0,2573
Prem 30 d	0,0218	0,1531	0,2435
Prem 60 d	-0,0485	0,1376	0,1803
Prem 90 d	-0,0435	0,1089	0,1774
Prem 120 d	-0,0632	0,0612	0,1610

The mean an trimmed mean are slightly positive for the 1 and 30 day- premium, whereas they are negative for the 60, 90 and 120 day- premium. This partly supports our hypothesis, to gain additional insight we perform a t- test. The results are given below:

One-Sample T: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d; Prem 120 d

Test of mu = 0 vs not = 0

Variable	N	Mean	StDev	SE Mean	95% CI	T
Prem 1 d	11	0,019562	0,141442	0,042646	(-0,075460; 0,114584)	0,46
Prem 30 d	11	0,000611	0,171590	0,051736	(-0,114664; 0,115887)	0,01
Prem 60 d	11	-0,021066	0,175256	0,052842	(-0,138805; 0,096673)	-0,40
Prem 90 d	10	-0,046181	0,183176	0,057925	(-0,177217; 0,084855)	-0,80
Prem 120 d	10	-0,069557	0,167014	0,052815	(-0,189032; 0,049918)	-1,32

Variable	P
Prem 1 d	0,656
Prem 30 d	0,991
Prem 60 d	0,699
Prem 90 d	0,446
Prem 120 d	0,220

The p- values are well above 5% meaning that the hypothesis cannot be rejected at a 95% significance level.

8.4.2 Peak contracts

The printout from Minitab below show the descriptive statistics for the peak load contracts:

Descriptive Statistics: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d; Prem 120 d

Variable	N	N*	Mean	SE Mean	TrMean	StDev
Prem 1 d	11	0	-0,0405	0,0872	-0,00564	0,2894
Prem 30 d	11	0	-0,0672	0,115	-0,00554	0,383
Prem 60 d	11	0	-0,0913	0,123	-0,0178	0,409
Prem 90 d	10	1	-0,111	0,138	-0,0298	0,436
Prem 120 d	10	1	-0,134	0,134	-0,0532	0,424

The mean an trimmed mean are negative for the 1, 30, 60, 90 and 120 day- premium. This partly supports our hypothesis, to gain additional insight we perform a t- test. The results are given below:

One-Sample T: Prem 1 d; Prem 30 d; Prem 60 d; Prem 90 d; Prem 120 d

Test of mu = 0 vs not = 0

Variable	N	Mean	StDev	SE Mean	95% CI	T
Prem 1 d	11	-0,040497	0,289363	0,087246	(-0,234894; 0,153900)	-0,46
Prem 30 d	11	-0,067218	0,383007	0,115481	(-0,324525; 0,190089)	-0,58
Prem 60 d	11	-0,091300	0,408715	0,123232	(-0,365879; 0,183278)	-0,74
Prem 90 d	10	-0,111488	0,436255	0,137956	(-0,423567; 0,200590)	-0,81
Prem 120 d	10	-0,134492	0,423578	0,133947	(-0,437502; 0,168518)	-1,00

Variable	P
Prem 1 d	0,652
Prem 30 d	0,573
Prem 60 d	0,476
Prem 90 d	0,440

Prem 120 d	0,342

The p- values are well above 5% meaning that the hypothesis cannot be rejected at a 95% significance level. However, although the tests don't statistically support our hypothesis of backwardation for quarter contracts are supported by the mean and trimmed mean of the peak premiums.

8.5 Test for structural change in the forward premium

In this part we test whether the extreme prices during the summer of 2003 lead to a structural change of the forward premium in the German power market, due to a learning effect. We test this hypothesis on the data for month premiums for both base load and peak load contracts, which we applied for the testing of the first hypothesis.

8.5.1 Base contracts

First, we test this for the base load data. Descriptive statistics for the sample period are given below:

Descriptive Statistics: Pre summer 2003; Summer 2003; After summer 2003

Variable	N	N*	Mean	SE Mean	TrMean	StDev	Minimum	Q1
Pre summer 2003	68	0	0,0183	0,0210	0,0151	0,1731	-0,2940	-0,1316
Summer 2003	12	0	-0,3528	0,0560	-0,3616	0,1941	-0,6536	-0,5067
After summer 2003	68	0	0,0760	0,0135	0,0758	0,1110	-0,2199	0,00691

Variable	Median	Q3	Maximum
Pre summer 2003	0,00129	0,1457	0,4281
Summer 2003	-0,3207	-0,2565	0,0357
After summer 2003	0,0653	0,1480	0,3876

These data show positive mean, trimmed mean, and median for the period pre and after the summer of 2003. The premium for the summer of 2003 shows negative values. We observe a considerable difference in the premium pre and after the summer of 2003.
Next we perform a one sample t- test to gain insight on the sign and sixe of the premiums. The results are given below:

One-Sample T: Pre summer 2003; Summer 2003; After summer 2003

Test of mu = 0 vs not = 0

Variable	N	Mean	StDev	SE Mean	95% CI
Pre summer 2003	68	0,018267	0,173103	0,020992	(-0,023633; 0,060167)
Summer 2003	12	-0,352795	0,194114	0,056036	(-0,476129; -0,229460)
After summer 2003	68	0,076031	0,111042	0,013466	(0,049153; 0,102908)

Variable	T	P
Pre summer 2003	0,87	0,387
Summer 2003	-6,30	0,000
After summer 200	5,65	0,000

The p- values and means indicate a positive premium for the period after the summer of 2003, and a negative premium for the Summer of 2003. The test show inconclusive results for the period pre summer of 2003. To test whether the mean pre and after the summer of 2003 is equal, we perform a one way ANOVA on the samples. The results are given below:

One-way ANOVA: Pre summer 2003; After summer 2003

```
Source   DF      SS      MS     F      P
Factor    1  0,1134  0,1134  5,36  0,022
Error   134  2,8338  0,0211
Total   135  2,9472

S = 0,1454   R-Sq = 3,85%   R-Sq(adj) = 3,13%
```

At a 95% level of significance the p- value of 0,022 is sufficient to reject the Hypothesis of equal means, which supports our hypothesis of increasing risk premiums. A paired t- test is performed to further investigate this. A paired t- test tests the following hypothesis

$$H_0 : \mu_{RP} \mathrm{PreSummer2003} - \mu_{RP} \mathrm{AfterSummer2003} = 0 \text{ vs}$$
$$H_1 : \mu_{RP} \mathrm{PreSummer2003} - \mu_{RP} \mathrm{AfterSummer2003} \neq 0$$

The results from the paired t-test are given below:

Paired T-Test and CI: Pre summer 2003; After summer 2003

```
Paired T for Pre summer 2003 - After summer 2003

                   N       Mean     StDev   SE Mean
Pre summer 2003   68   0,018267  0,173103  0,020992
After summer 200  68   0,076031  0,111042  0,013466
Difference        68  -0,057764  0,221289  0,026835

95% CI for mean difference: (-0,111327; -0,004200)
T-Test of mean difference = 0 (vs not = 0): T-Value = -2,15  P-Value = 0,035
```

The confidence interval for the mean difference does not include zero, which suggests a difference between them. H_0 is rejected at a significance level of 95%, with a p- value of 3,5%. The all negative confidence interval, support our hypothesis of a significant increase in the forward premium after the summer of 2003. However we decided to perform an additional statistical test to increase the reliability of the conclusion. The two- sample t-test is an un- paired test for the following hypothesis for the same hypothesis. The difference is that….

Two-Sample T-Test and CI: Pre summer 2003; After summer 2003

```
Two-sample T for Pre summer 2003 vs After summer 2003

                   N   Mean  StDev  SE Mean
Pre summer 2003   68  0,018  0,173    0,021
After summer 200  68  0,076  0,111    0,013


Difference = mu (Pre summer 2003) - mu (After summer 2003)
Estimate for difference:  -0,057764
95% CI for difference:  (-0,107169; -0,008359)
```

```
T-Test of difference = 0 (vs not =): T-Value = -2,32  P-Value = 0,022  DF =
114
```

We observe that also this test rejects H_0 at a 95 % significance level, with a p- value of 2,2%. This supports our hypothesis.
To justify the use of t- tests we perform a normality test on the samples. The results of the normality test are given in figures 8.2.4 and 8.2.5.

Figure 8.5.1: Normal probability plot for the pre summer 2003 data

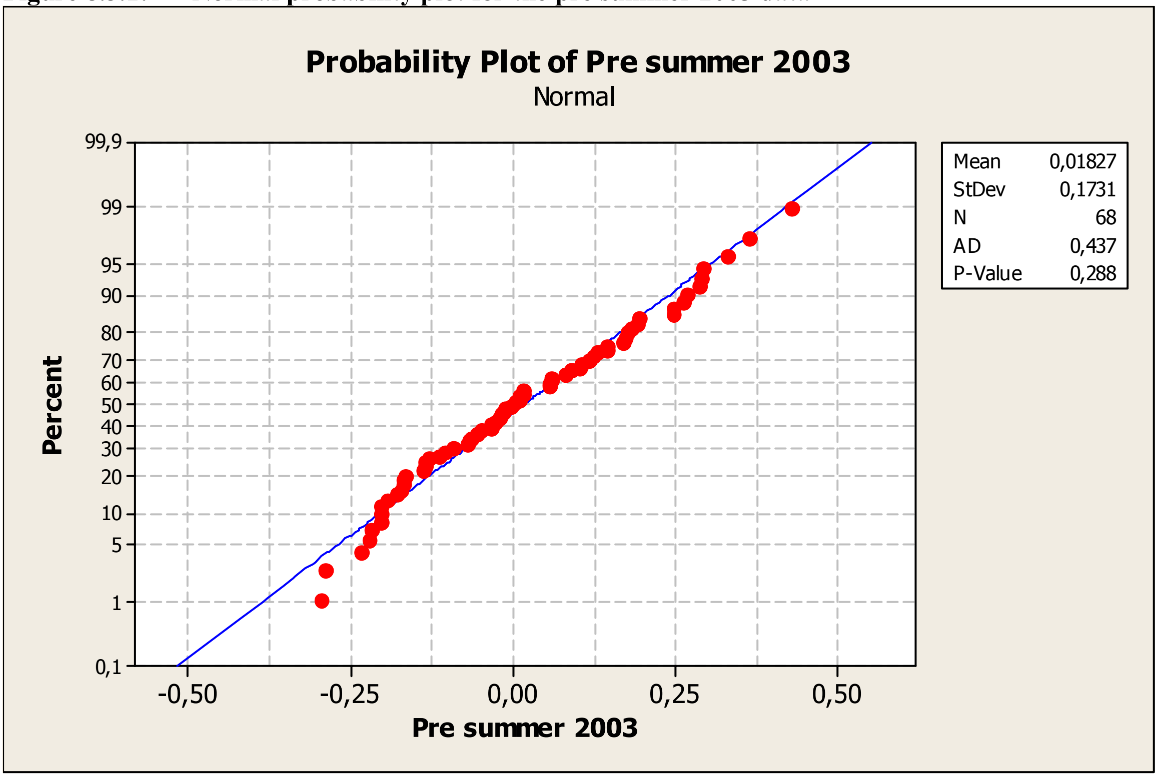
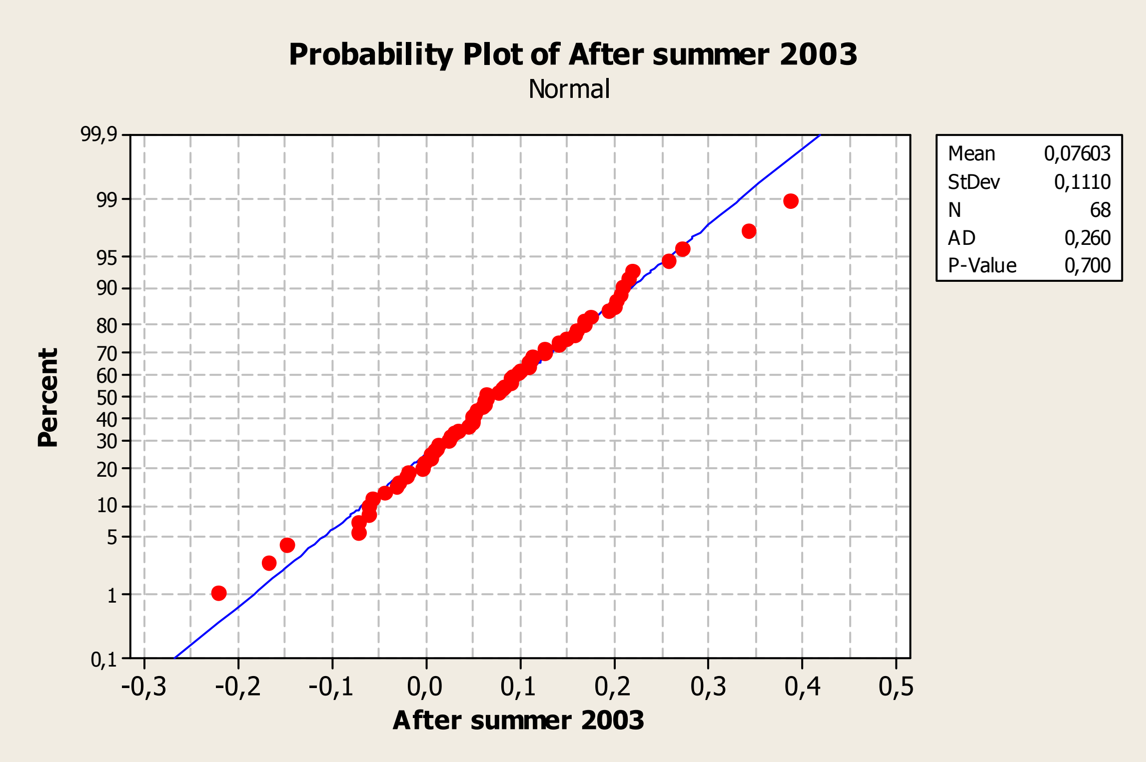


Figure 8.5.2: **Normal probability plot for the after summer 2003 data**



The p- values of 0,288 and 0,700 support our assumption of normality for the two data sets at a 95% significance level, and justify the use of t- tests.

8.5.2 Peak contracts

Then, the same analysis is performed on the quarter peak load contracts.

Descriptive Statistics: Pre summer 2003; Summer 2003; After summer 2003

```
Variable            N  N*     Mean  SE Mean   TrMean   StDev  Minimum       Q1
Pre summer 2003    68   0   0,0240   0,0257   0,0230  0,2120  -0,3556  -0,1746
Summer 2003        12   0  -0,3963   0,0641  -0,4130  0,2221  -0,7159  -0,5861
After summer 200   68   0   0,1524   0,0160   0,1511  0,1323  -0,2218   0,0696

Variable           Median       Q3  Maximum
Pre summer 2003    0,0530   0,1877   0,4803
Summer 2003       -0,3613  -0,2949   0,0903
After summer 200   0,1398   0,2381   0,5300
```

These data show positive mean, trimmed mean, and median for the period pre and after the summer of 2003. The premium for the summer of 2003 shows negative values. We observe a considerable difference in the premium pre and after the summer of 2003.
Next we perform a one sample t- test to gain insight on the sign and sixe of the premiums. The results are given below:

One-Sample T: Pre summer 2003; Summer 2003; After summer 2003

```
Test of mu = 0 vs not = 0
```

```
Variable           N       Mean     StDev   SE Mean          95% CI
Pre summer 2003   68   0,023980  0,212002  0,025709  (-0,027335;  0,075295)
Summer 2003       12  -0,396308  0,222051  0,064101  (-0,537393; -0,255224)
After summer 200  68   0,152407  0,132339  0,016048  ( 0,120374;  0,184440)

Variable              T      P
Pre summer 2003    0,93  0,354
Summer 2003       -6,18  0,000
After summer 200   9,50  0,000
```

The p- values and means indicate a positive premium for the period after the summer of 2003, and a negative premium for the Summer of 2003. The test show inconclusive results for the period pre summer of 2003. To test whether the mean pre and after the summer of 2003 is equal, we perform a one way ANOVA on the samples. The results are given below:

One-way ANOVA: Pre summer 2003; After summer 2003

```
Source   DF      SS      MS      F      P
Factor    1  0,5608  0,5608  17,96  0,000
Error   134  4,1847  0,0312
Total   135  4,7455

S = 0,1767   R-Sq = 11,82%   R-Sq(adj) = 11,16%
```

With a p- value of 0,00 the Hypothesis of equal means are rejected on all levels of significance, which supports our hypothesis of increasing risk premiums. A paired t-test and two sample t- test, equivalent two the ones applied for the base load contract, are performed to further investigate this. The results from the test are given below:

Paired T-Test and CI: Pre summer 2003; After summer 2003

```
Paired T for Pre summer 2003 - After summer 2003

                   N       Mean     StDev   SE Mean
Pre summer 2003   68   0,023980  0,212002  0,025709
After summer 200  68   0,152407  0,132339  0,016048
Difference        68  -0,128427  0,266943  0,032372


95% CI for mean difference: (-0,193041; -0,063813)
T-Test of mean difference = 0 (vs not = 0): T-Value = -3,97  P-Value = 0,000
```

Two-Sample T-Test and CI: Pre summer 2003; After summer 2003

```
Two-sample T for Pre summer 2003 vs After summer 2003

                   N   Mean  StDev  SE Mean
Pre summer 2003   68  0,024  0,212    0,026
After summer 200  68  0,152  0,132    0,016


Difference = mu (Pre summer 2003) - mu (After summer 2003)
Estimate for difference:  -0,128427
95% CI for difference:  (-0,188476; -0,068378)
T-Test of difference = 0 (vs not =): T-Value = -4,24  P-Value = 0,000  DF =
112
```

We observe all negative, and very similar 95% confidence intervals for both the tests. This supports our hypothesis. The p- value are 0,0% for both tests, rejecting equal means for all significance levels.

9 Discussion and conclusions

9.1 Discussion of the empirical results

This chapter discusses the results of our empirical analyses compared to the hypothesis in chapter …
Her eller ett annet sted må vi ta med noe om størrelsen på forward premium, opp mot effektivitet, benchmarking opp mot andre land og noe om det fakta at musgens allerede har påvist markedsmakt og høyere priser og at premien kommer i tillegg til dette.
Vurder å ta med følgende:
One interesting feature of these numbers is that the forward premium is decreasing with increasing time to maturity. This is the opposite of what one would expect, and also what Mork (2004) found for the Nordic electricity market: larger premiums the further they are from delivery (i.e., larger premiums for larger risk). We are uncertain about the reason for this peculiar result, one contributing factor could be that retailers wait until the last couple of weeks before they ente

9.1.1 Hypothesis 1

Base load contracts:
For the risk premium on base load month contracts estimated for the entire period, we don't find significant premiums for the 1, 30, 60 or 90- day premiums. The p- values from the tests are 0,143, 0,416, 0,769, and 0,670 respectively. However the mean values are positive for all but the 90- day premium. The results of the estimation where the data for the summer of 2003 are left out are more supportive of our hypothesis. Here we find significant premiums for the 1 and 30- day premium, with p-values of 0,023 and 0,042 respectively. We don't find significant premiums for the 60 and 90- day premium, with p- values of 0,064 and 0,320. The means of the premiums are positive for all the samples. We observe that the premiums increases as we move toward maturity date, this is the opposite of the results Mork (2004) find for the month contracts in NordPool. One plausible explanation for this is that retailers in EEX secure their volume only weeks before delivery, and thereby induce an increase in the forward premium.

Peak load contracts:
For the risk premium on the peak load month contracts estimated for the entire premium, we find significant premium for the 1- day premium, with a p- value of 0,037. For the 30, 60 and 90- day premiums, we don't fond significant premiums with p- values of 0,119, 0,294 and 0,566 respectively. The means are positive for all samples, and bigger than for the base load contracts, as expected. The results of the estimation where the data for the summer of 2003 are left out are more supportive of our hypothesis. Here we find significant premiums for the for all the peak load

contracts, with p- values of 0,004, 0,005, 0,004 and 0,043 respectively. We observe that the results from the tests on peak contracts are more supportive of our hypothesis, and show consistent higher mean values for premiums. This is in line with our expectations of higher risk premiums for peak load contracts due to the relatively more skewed distribution of spot peak prices compared to spot base prices.

9.1.2 Hypothesis 2

Base load contracts
We find positive mean values of the forward premiums are positive from October to May, however the p- values are only significant for May, November and December. The mean values are negative for June, July, August and September, with significant p- values for June, July and August. The positive premiums for the winter months are in line with our hypothesis. However, we get negative premiums for the summer months, contradicting our hypothesis. One explanation for this is that the market still is young, and that market participants still are learning about the dynamics of the market. Also, we have included the data from the summer of 2003 in our analysis and this data show betydelige negative values that could affect our results. Another observation supporting our hypothesis is that the mean values of the spring and autumn months are lower than the mean premiums for winter. This is in line with our expectations of higher premiums for months with more skewed spot prices.

Peak load contracts
For the peak contracts we find positive mean values from September to May, however the p- values are only significant for March, April, May, November and December. The mean values are negative for June, July and August, with significant p- values for June and July. . The positive premiums for the winter months are in line with our hypothesis. However, we get negative premiums for the summer months, contradicting our hypothesis. One explanation for this is that the market still is young, and that market participants still are learning about the dynamics of the market. Also, we have included the data from the summer of 2003 in our analysis and this data show betydelige negative values that could affect our results. Another observation supporting our hypothesis is that the mean values of the spring and autumn months are lower than the mean premiums for winter. This is in line with our expectations of higher premiums for months with more skewed spot prices, induced by increased demand side hedging pressure for these months.

9.1.3 Hypothesis 3

Base load contracts
For the risk premium on base load month contracts estimated for the entire period, we don't find significant premiums for the 1, 30, 60 or 90- day premiums. The mean values are negative for the 60, 90 and 120 day premiums and their values are –0,0211, –0,046 and -0,070 respectively. The median for the same samples are all negative. Although we don't find significance these results clearly indicates lower risk premiums for the quarter contracts, supporting our hypothesis.

Peak load contracts

The results from the tests on the peak load contracts also show no significant premiums for the 1, 30, 60 or 90- day premiums. The mean values are negative for the 1, 30, 60, 90 and 120 day premiums and their values are –0,041, -0,067, -0,091, -0,11 and –0, 13. The medians are also negative for all the samples. Although no significance, the results here are supportive of our hypothesis. The very limited number of observations in our samples probably explains the lack of significance.

9.1.4 Hypothesis 4

Base load contracts
Our estimations show mean the risk premium pre and after the summer of 2003 of 0,018 and 0,076 respectively. The medians and the trimmed mean estimated for the same sample show similar results. The p- values show that the pre- summer results are not significant, whereas the after- summer results are significant. The one- way ANOVA rejects the hypothesis of equal means pre and after the summer of 2003, with a p- value of 0,022. The paired t- test and the two- sample t- test also rejects that the difference of the means equal zero, with p- values of 0,035 and 0,022. Also we observe the following 95% confidence intervals for the paired t- test and the two sample t- test: (-0,111; -0,0042) and (-0,107; -0,0084). These tests support our hypothesis of an increased risk premium due to learning effects. Another plausible explanation for this, is that this has happened due to increasing volatility in the German power market induced by market power by generators, in order to extract increased premiums. No matter how you interpret the results, they have caused more expensive hedging for the demand side in the German power market, and a market that are less efficient from their point of view.

Peak load contracts
The estimations for the peak load premiums show similar results as for the base load contracts. The mean risk premiums pre and after the summer of 2003 were 0,024 and 0,152 respectively. The medians and the trimmed mean estimated for the same sample show similar results. The p- values show that the pre- summer results are not significant, whereas the after- summer results are significant. The one- way ANOVA rejects the hypothesis of equal means pre and after the summer of 2003, with a p- value of 0,0. The paired t- test and the two- sample t- test also rejects that the difference of the means equal zero, with p- values of 0,00 and 0,00. Also we observe the following 95% confidence intervals for the paired t- test and the two sample t- test: (-0,193; -0,0638) and (-0,188; -0,068). These tests strongly support our hypothesis of an increased risk premium due to learning effects.

9.1.5 Sources of error estimating the risk premium

The main uncertainty factor connected to estimations of risk premiums is how one chooses to estimate the expected spot price. The expected spot price is very likely to be based on assumptions about the factors determining supply and demand.
In our empirical analyses we estimate the ex- post, or realized forward premiums. An implicit assumption using this framework is that the expected spot prices equal actual market prices in the delivery period for a contract. This hypothesis of unbiasedness could be restrictive in the presence of information asymmetries, learning and market

inefficiencies. This is definitely a valid point for the German market, which is a young and immature market where we throughout this paper have argued that information asymmetries, learning and market inefficiencies definitely are present. The fact that our analysis period are short and that this has been a period of turbulence for the German power market add to this problem. Many of the periods of extreme prices during the analysis period were, as explained in the price analysis, caused by unexpected incidents, not demand peaks.

Our framework will in such periods underestimate the forward premium in the market, because the expected spot price we use in our estimations are higher than what the market actually expected. For instance there are no way the market could have expected the extreme prices of the summer of 2003, and all the incidents leading to it. Also, the extreme prices during the winter of 2001, partly caused by the ENRON bankruptcy, would be impossible to predict. These weaknesses have definitely impacted our estimations, and are some of the explanation of the unexpected negative premiums for the summer. However, the alternative methods of calculating the risk premiums also have similar problems connected to them.

9.2 Conclusions

In the last section of this thesis we have presented the main functions for a future market and the criteria needed for functional futures markets. We find that some of the criteria for functional futures markets are not fulfilled in the German power market;
We also present future pricing theory for equilibrium pricing in electricity markets, and how this relate to the hedging pressure and expectations for risk premiums for the different forward contracts traded at EEX. We find that for the producers, the optimal positions depend on the ability to benefit from variations in the prices, production technology, yearly variations in the skewness of spot prices and ….. For the retailers, we find that their hedging needs are dependent on their exposure to high demand in periods of high prices and, as for producers, the skewness and variation of skewness throughout the year. Based on the theory presented, we present four hypothesis regarding the risk premium; we expect a positive risk premium on average for the short- term contracts (month contracts), regular variations for this short- term premium throughout the year, a negative long term premium (quarter contracts) and a structural change for the short- term premium, due to learning effects in the market following the period of volatile prices culminating in the extreme prices of the summer of 2003. We also expected overall higher risk premiums for peak load contracts than the baseload contracts, due the higer skewness and kurtosis for the peak price distribution.

Based on three years of data, we find

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Appendix