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Risk Management in the German Electricity Market: The Case of Power-Trading Utility Companies

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I. Content

II. List of Abbreviations

AktG	Public Company's Act (Aktiengesetz)
ANN	Artificial neural network model
AR	Autoregressive
ARE	Arbeitsgemeinschaft regionaler Energieversorgungs-Unternehmen
ARMA	Autoregressive moving average model
BDI	Bundesverband der Deutschen Industrie e.V.
BKartA	German Federal Cartel Office (Bundeskartellamt)
BMU	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit
CMD	Chicago Mercantile Exchange
C-VaR	Conditional Value-at-Risk
DIHT	Deutscher Industrie- und Handelskammertag
DVG	Deutsche Verbundgesellschaft
e&i	Elektrotechnik und Informationstechnik (magazine)
ECC	European Commodity Clearing AG
EEG	Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz)
EEX	European Energy Exchange
ENTSO-E	European Network of Transmission System Operators for Electricity
EnWG	Energy Economic Law (Energiewirtschaftsgesetz)
EOE	European Options Exchange
EPEX Spot	European Power Exchange Spot
ESC	Electricity Supply Companies
ET	Energiewirtschaftliche Tagesfragen (magazine)
EU	European Union
GmbHG	Limited Liability Company's Act (Gesetz betreffend die Gesellschaften mit beschränkter Haftung)
GWB	Act against Restrains of Competition (Gesetz gegen Wettbewerbs-beschränkungen)
HGB	Code of Commercial Law (Handelsgesetzbuch)
IAS	International Accounting Standards
ICT	Information and Communication Technology
IEE	Institution of Electrical Engineers
IFRS	International Financial Reporting Standards
IMA	Institute for Mathematics and its Applications
KonTraG	Control and Transparency in Business Act (Gesetz zur Kontrolle und Transparenz im Unternehmensbereich)

KoR	Zeitschrift für kapitalmarktorientierte Rechungslegung (magazine)
LIFFE	London International Financial Futures Exchange
MA	Moving average
MtM	Marking-to-Market
OECD	Organisation for Economic Cooperation and Development
OTC	Over-the-counter
P-ARCH	Periodic generalized autoregressive coefficients heteroscedasticity model
Phelix®	Physical Electricity Index
SOX	Sarbanes-Oxley Act
STAR	Smooth transition autoregressive model
StromGVV	Ordinance Regulating the Provision of Basic Electricity Supplies (Stromgrundversorgungsverordnung)
TSO	Transmission System Operators
uwf	UmweltWirtschaftsForum (magazine)
VaR	Value-at-Risk
VDEW	Verband der Elektrizitätswirtschaft
VDN	Verband der Netzbetreiber
VIK	Verband der Industriellen Energie- und Kraftwirtschaft e.V.
VKU	Verband kommunaler Unternehmen
VV	Verbändevereinbarung
WUW	Wirtschaft und Wettbewerb (magazine)
zfbf	Zeitschrift für betriebswirtschaftliche Forschung (magizine)
ZfE	Zeitschrift für Energiewirtschaft (magazine)
ZNER	Zeitschrift für Neues Energierecht (magazine)

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1 Introduction

1.1 Motivation and Determination of the Topic

Modern societies are facing energy and environmental challenges. In a framework of climate change, escalating global energy consumption, declining fossil sources, and uncertainties regarding future supply, one key question of the 21st century is how to secure a clean and efficient power provision.[1] If even today readily available non-fossil sources are not able to satisfy the power demand, the transition to new energies is unavoidable.[2] This causes the high dynamic of the energy sector within a constantly changing economic, social, and political environment and opens an important and interesting field of research that motivates to write this thesis. Thereby, the focus is on one of the most significant commodities, electric energy. Electricity markets have recently undergone major changes[3], which have affected new chances and risks for involved market participants.

Worldwide efforts to encounter the changes in the energy sector lead to different developments.[4] To fix a scope, which is possible to handle within this thesis, it is appropriate to limit the analysis to one electricity market. Due to the importance of the European Energy Exchange (EEX) in Leipzig, the leading energy exchange in Continental Europe,[5] the German electricity market is in the focus of this analysis.

In the focus are power-trading utility companies (utilities) without own production capacities. Choosing a ‘pure’ trader on the electricity market reflects the increasing importance of power trading in liberalized energy markets,[6] which are characterised in the second chapter. Excluding market participants with own production potential determines the topic and restricts the chances and risks as well as the corresponding risk management techniques. For instance, there are possibilities such as using different kind of power plants with various marginal costs (see 3.1.3) or make-or-buy decisions that enable power-producing companies to optimize their total profit or risk-and-return ratio.[7] However, these are no options for a ‘pure’ trading utility. Therefore, this thesis concentrates on the identification, measurement, and evaluation of such special risks. Basing on this assessment, a risk management process for an exemplary ‘pure’ power-trading utility company taking different risk management strategies, techniques, and instruments into account is analysed in the following.

[1] Cf. Percebois (2008), p. 1f.
[2] Cf. Smil (2006), p. 22f.
[3] Cf. Ross/Kolos/Tompaidis (2006), p. 627.
[4] Cf. Joskow (2008), p. 9f.
[5] Cf. EEX (2010a), p. 1; Percebois (2008), p. 4.
[6] Cf. Sioshansi (2002), p. 449.
[7] Cf. Jahn (2008), p. 299f.

1.2 Research Questions and General Structure

Various challenges containing different kind of risks, indicated in the previous section, cause new requirements and tasks for the corporate management of power-trading utilities.[8] As characterised in 2.3 the risk management process slips into the focus of current efforts and leads to the basic research question of this thesis:

> "*How can a power-trading utility create its risk management process in order to encounter the changing framework in the German electricity market?*"

For the structured analysis of an optimal design of this process, the leading research question is subdivided into three secondary questions following the classic risk management process. In general, it starts with risk identification, measurement, and evaluation, followed by risk control, with risk management instruments, and ends up with risk controlling based on the chosen risk management strategy.[9]

a) Which influence has the liberalization of the German electricity market got on the environment and framework of a power-trading utility?

To illustrate the relevance and importance of this topic, it is essential to analyse the reasons and effects of the indicated changing environment for power trading in the German electricity market in chapter 2. The characterised framework sensitizes for chances and occurring fields of risk and problems for utilities, which are operating within this market.

b) Which risks result from this development (risk identification)? How can a utility evaluate and measure such risks in order to deal with them?

Not only the identification of risks but also their categorizing in 3.1 enables a structured analysis in chapter 3. The evaluation of the main risk, fluctuating electricity prices,[10] in 3.2 is essential to understand how volatile and eventful the German electricity market is. It provides important fundamentals[11] for measuring the risks in 3.3 and finally developing adequate strategies using effective instruments.

c) Which kind of objectives can utilities pursue with their risk management process under these terms? How to use different risk management instruments to realize the chosen strategy?

After evaluation and measurement of the risks, the corporate management of the utility has to decide how to face these challenges. Different general kinds of risk

[8] Cf. Todem/Stigler (2002), p. 170.
[9] Cf. Wolke (2008), p. 4.
[10] Cf. Sioshansi (2002), p. 450f.
[11] Cf. Pilipovic (2007), p. 2.

management objectives and strategies characterised in 4.1 are possible. Knowing the company's risk management policy the assessment of potential risk management instruments in 4.2 can consider the intention behind their potential utilization.
Finally, this process builds the basis for analysing different risk management strategies in 4.3 and sensitizes for accruing limits and problems of power trading in the German electricity market (see 4.4).

Answering the secondary questions in the mentioned sections makes it possible to sum up the results within the final chapter 5 and to answer the basic research question. Thereby, the structure of this study allows involving empirical data of the EEX and other institutions in order to consolidate the analysis. Furthermore, this thesis provides an outlook on potential developments and gives indications for further fields of research.

2 Relevance of Risk Management in the German Electricity Market

2.1 Development of the German Electricity Market

The basis for the development of the German electricity market after World War II was the cooperation of national grid companies to establish a framework that enables the distribution of power over long distances.[12] German electricity supply companies (ESC) founded in 1948 the Deutsche Verbundgesellschaft (DVG) to coordinate the national electricity transformation network with the objective to reconstruct and extend the power grid in order to enlarge the efficiency of electric energy supply.[13] To ensure a failure-free operation, permanent adaption of produced electricity to fluctuating demand is essential. In the end, the necessity to compensate load differences is the basis for power trading in liberalized electricity markets.[14]

Due to the strategic importance of power for modern economics,[15] governments intervene to enforce political aims.[16] This framework of some big ESCs coordinating the transmission and political interventions caused the traditional structure of compound trading between a limited number of market participants. The core element of this regime was the division of the German electricity market into sales territories. The end-customers were legally bound to buy power from the ESC of their region. In return, the ESC had the obligation to provide electricity to each customer and there was a regulatory supervision of the electricity prices.[17] Thus, the ESC had a monopoly position within their service areas. Because the contracts that guaranteed this situation would have impinged the competition law, the German Act against Restrains of Competition (GWB) contained a special article that exclusively allowed such agreements.[18] In the end, prices and regions where regulated within the monopolistic German electricity market without real competition.

Basing on the hope that competition in the electricity sector would lead to cheaper power prices, several countries started to deregulate these markets at the end of the 1980s.[19] Therefore, directive 96/92/EC from 12/19/1996 of the European Union (EU) forced the development of a competitive electricity market in order to establish smooth operation of the European internal market. Besides the establishment of competition, the transmission network is especially in view in order to ensure the security, reliability,

[12] Cf. Zahoransky (2009), p. 354.
[13] Cf. Suck (2008), p. 87.
[14] Cf. Jochum/Pfaffenberger (2005), p. 74f.
[15] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 113.
[16] Cf. Ockenfels (2007), p. 46.
[17] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 171; Heuck/Dettmann/Schulz (2007), p. 486f.
[18] Cf. § 103 GWB (old version); Kleest/Reuter (2002), p. 6.
[19] Cf. Ockenfels (2007), p. 46.

and efficiency of the system with transparent and non-discriminatory criteria regarding its access. To enable the EU and the member states to carry out their checks, unbundling and transparency of the company's accounts were also included in these rules. According to article 27 of directive 96/92/EC, the member states had to transform these regulations into national law by February 1999.[20]

Germany followed in 1998 with the revision of the Energy Economic Law (EnWG).[21] To realize the requirements of this law, the parties involved implemented the Verbände-vereinbarung (VV) in 1999 and its update the VV II in 2001 to establish criteria for system usage charges and principles for non-discriminatory access to the power grid following directive 96/92/EC.[22] Further regulations of various market members such as the transmission code for network and system rules of the German transmission system operators (TSO)[23] or the Operations Handbook of the European Network of Transmission System Operators for Electricity (ENTSO-E) followed. ENTSO-E is a cooperation of 42 European TSO to ensure an optimal management and the stability of the electricity transformation network.[24] Hence, the concrete execution of the laws is left to the market participants. Such a complete market liberalisation of the German electricity market contains the risk of regulatory deficiency and insufficient realization of competition due to the market power of the former monopolistic enterprises, and their tendency to primarily enforcing their own interests.[25]

The current development of the German electricity market tends to some kind of re-regulation because of the insufficient progress of establishing a real completive market after the liberalisation in 1998.[26] Depending on the technique of determination, the EnBW AG, E.ON AG, RWE AG, and Vattenfall AB produced 71% to 91% of the net amount of German electricity in 2007. Whereas E.ON and RWE dominated the market with about 57% of the production.[27] Due to this oligopolistic structure, the German Federal Cartel Office (BKartA) ascertained the market control of both firms and supposed that all four dominating companies have the ability to influence the market prices on the EEX.[28] Independent investigations confirm that the retention of production capacities could have a massive effect on the electricity price.[29] Hence, there is a trend of increasing intervention and regulation to enforce the achievement of the original

[20] Cf. Directive 96/92/EC of 19 December 1996.
[21] Cf. § 1 EnWG; Suck (2008), p. 282.
[22] Cf. Bundesverband der Deutschen Industrie e.V. (BDI), et al. (2001), p. 2f.
[23] Cf. Verband der Netzbetreiber e.V. (VDN) (2007), p. 1-84.
[24] Cf. ENTSO-E, online on the internet: https://www.entsoe.eu, access: 08/13/2010, 02:57 pm.
[25] Cf. Becker (2010), p. 399.
[26] Cf. Jahn (2008), p. 298; Joskow (2008), p. 10, Ockenfels (2007), p. 46.
[27] Cf. Haucap, et al. (2009), p. 46, No. 80; Jahn (2008), p. 298.
[28] Cf. Haucap, et al. (2009), p. 4-5, No. 8-9.
[29] Cf. Markert (2009), p. 71.

objective of market deregulation: A free and efficient market with low power prices. To influence the market development the Conference of Economic Ministers founded a task force to improve transparency and pricing on the German electricity market in 2007.[30]

In spite of the difficulty with some ESC's market power, market liberalisation is the basis for the development of market-based power trading in the current German electricity market following the economic law of supply and demand with the corresponding chances and risks,[31] which are in the focus of this thesis.

2.2 Non-Storability of Electric Energy

In contrast to regulated markets with fixed and state-controlled prices[32] based on long-term agreements, the main characteristic of market liberalisation is the sensitive reaction of market prices to changes in supply and demand.[33] The volatility of electricity prices is enormously high, especially in deregulated power markets.[34] To understand the extreme behaviour of the market prices it is important to realize that electric energy differs, especially in one characteristic, from other commodities.

Electricity is not physically storable in a direct way or in sufficient amounts.[35] Traditional ways of storing are pumped storage hydro power stations but their potential in Germany is geographically limited. Other technologies are capacitors or accumulators but these can only provide limited transitory periods, have short durability, work at high costs, and in the end are not acceptably economic. Newer technologies such as the transformation of electricity into hydrogen are not fully developed.[36] Finally, alternatives such as E-Mobility to use electrified automobiles as decentralised energy storage units are in early phases of conception or testing, have confronted several barriers, and are far away from an efficient commercial utilization.[37]

It is not possible to build a remarkable stock of electric energy to provide reserves for a continuous power supply in any situation. On the other hand, power demand depends on various factors that are hard or impossible to forecast (see chapter 3). However, to ensure the required secure and efficient operation of the transmission system,[38] the non-storability of electricity leads to the need of a real-time adjustment of local supply

[30] Cf. Becker (2010), p. 400.
[31] Cf. Huurman/Ravazzolo/Zhou (2007), p. 2.
[32] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 171.
[33] Cf. Burger/Graeber/Schindlmayr (2007), p. 133.
[34] Cf. Todem/Stigler (2002), p. 170.
[35] Cf. Escribano/Peña/Villaplana (2002), p. 4.
[36] Cf. Ellersdorfer (2007), p. 80f.
[37] Cf. Schönfelder, et al. (2009), p. 376-378.
[38] Cf. § 1 EnWG; Article 2 Directive 96/92/EC.

to the demand.[39] Due to the market mechanism on the liberalised German electricity market, this adjusting is reflected by the power price.[40] The process of pricing depends on overlapping seasonality, type of power production, weather conditions, and other issues, which are analysed more detailed in 3.1.3.

At this point, it is essential to record, that power trading under such circumstances means uncertainty about the cost of procurement and sales revenues due to the volatile price.[41] Hence, risk management is an important factor to operate in such a framework. Its connection with power trading is characterised in the next section.

2.3 Risk Management and Power Trading

In the regulated electricity market, risk management was a relatively unimportant corporate function because fixed prices, fixed sales territories, and no real competition caused planning stability and allowed utilities to pass on their costs to the end-customers.[42] In liberalized markets in contrast, uncertainty regarding future supply and demand, regional and temporal price variations as well as the development of a competitive environment force a rethinking.[43]

In addition, starting in the same phase as the power market liberalization in the electricity sector, risk management moves into the focus of the policy. The German Control and Transparency in Business Act (KonTraG) became law in 1998. In addition, the revision of the Public Company's Act (AktG) and the Limited Liability Company's Act (GmbHG) established a legal framework that forces a comprehensive due diligence. The extension of the reporting requirements by the obligation to publicise business risks especially increases the relevance of risk management in non-financial companies such as utilities.[44] Thus, the German code of commercial law (HGB) for example, forces the reporting of objectives and methods of risk management for all transactions that are related to the usage of financial instruments.[45]

Furthermore, based on the development in US-American companies the concept of shareholder value has taken precedence in Germany since the 1990s.[46] Globalisation and a more intensive competition regarding investment capital increased the focus of companies on the shareholders' interests.[47] As a result, shareholders became more

[39] Cf. Eydeland/Wolyniec (2003), p. 5.
[40] Cf. Huurman/Ravazzolo/Zhou (2007), p. 2.
[41] Cf. Robinson (2000), p. 528.
[42] Cf. Burger/Graeber/Schindlmayr (2007), p. VI.
[43] Cf. Sioshansi (2002), p. 450.
[44] Cf. Wolke (2008), p. 2.
[45] Cf. § 289, II, No. 2 HGB.
[46] Cf. Bernhardt (2000), p. 327f.
[47] Cf. Schilling (2001), p. 150.

influential and demanded detailed information regarding the usage of their investment and the corresponding risks. Thus, the relevance of risk management was reinforced.[48] Even if this characterisation of reasons for the increased relevance is not conclusive, it caused sensitivity for the importance of risk management in liberalized markets.

In Germany, the scenery of utilities is very heterogeneous compared with other European countries. The huge number of small local up to big regional utility companies reflects the German federal structure.[49] The liberalization of the electricity market opened the wholesale energy trading business area. New segments contain chances for profits. However, they also contain manifold areas of risks and possible losses up to potential bankruptcy.[50] Using the deregulated commodity markets for risk diversification made portfolio management techniques relevant in the electric power industry. However, in spite of such risk diversification possibilities managers of utilities are confronted with further risks within their operations.[51]

In the course of this thesis, it will become obvious, that the non-storability of electricity characterised above and the corresponding high volatility of its price (see 3.3) can lead to dramatic effects on the value of the power-trading utility company's portfolio. The price risk of electricity is more complex than in other markets. Hence, hedging this risk category is a central motive of utilities.[52] In general, the requirements of an efficient risk management system in the German electricity market are higher than in many other braches. Therefore, the implementation and realization of a risk management strategy in the power sector is more challenging.[53]

Trading with different kind of financial products on organised exchanges like the EEX or with bilateral contracts that are fixed over-the-counter (OTC) are new possibilities to hedge such risks and have become more important within the last years.[54] Utilities are forced to meet these new challenges. Thereby, it is essential to identify, evaluate, and measure the potential inherent risks of the new fields (see chapter 3). Then it is possible to develop and implement specific risk management strategies (see chapter 4) to optimize the utility's risk-and-return ratio.[55]

[48] Cf. Bartram (2000), p. 313.
[49] Cf. Wildemann (2009); p. 31-33.
[50] Cf. Bessembinder/Lemmon (2006), p. 1755f.
[51] Cf. Fleten/Wallace/Ziemba (2002), p. 71.
[52] Cf. Al Janabi (2009), p. 16f.
[53] Cf. Todem/Stigler (2002), p. 170.
[54] Cf. Hilpold (2009), p. 389f.
[55] Cf. Al Janabi (2009), p. 16; Todem/Stigler (2002), p. 170.

3 Identification, Evaluation, and Measurement of Risks

3.1 Risk Identification

3.1.1 Risks of a Utility Company in the German Electricity Market

The first step in effective risk management is the determination of a utility's main risks regarding trading with electricity. A common classification is the differentiation between financial and non-financial risks.[56] Financial risks consist of the market and the credit risk. Due to the changing environment and increasing dynamic of power prices, financial risks have become significant.[57] Hence, they are in focus of this analysis. To enable a clear classification, even if not conclusive, non-financial risks are also mentioned but their analysis is mostly beyond the scope of this study.

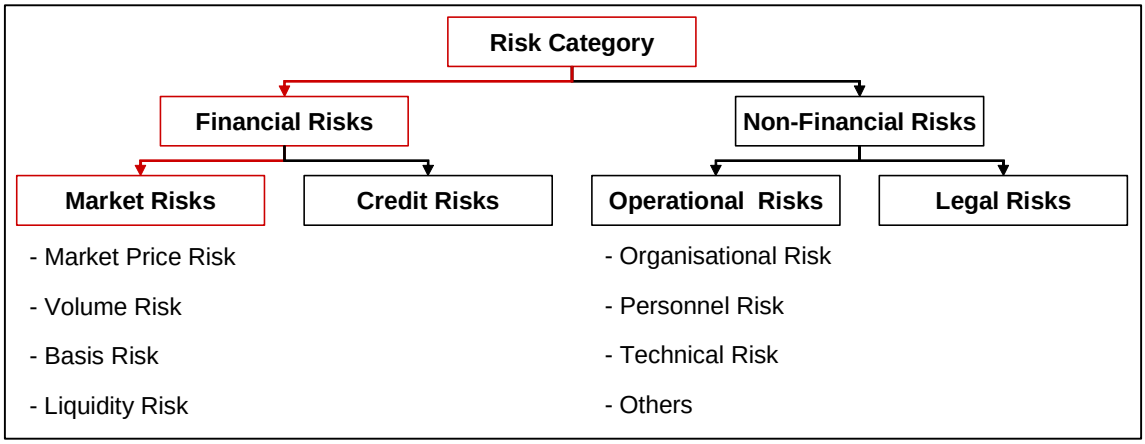

Figure 1: Risk Categories of a Power-Trading Utility Company[58]

The counterparty risk consists of two general kinds of risks. Firstly, it comprises the bad dept in case of illiquidity of the counterpart,[59] which is for a utility the end-customer or the trading partner. Even if it is an important factor, in this analysis, such credit risks are not of special interest because the European Commodity Clearing AG (ECC) is the established clearinghouse on the EEX and protects traders against default.[60] Secondly, the replacement risk is caused by an incomplete or not at all delivery of the supplier respectively purchase of the customer. In this case, the utility company has to procure the necessary respectively sell the redundant volumes at current prices.[61] Therefore, the replacement risk can be assigned to the volume risk.

On basis of this argumentation, the market risk is identified as the central risk with particular interest to a power-trading utility on the EEX. To enable the handling of the

[56] Cf. Rosenkranz/Missler-Behr (2005), p. 187f; Wolke (2008), p.6.
[57] Cf. Wang/Min (2008), p. 365.
[58] Source: Bergschneider/Karasz/Schumacher (1999), p. 206-233; Lehrmann (2001), p. 215.
[59] Cf. Holst (2001), p. 135f.
[60] Cf. ECC (2010), p.3; Grichnik/Vortmeyer (2002), p. 389.
[61] Cf. Kremp/Rosen (2002), p. 48f.

market risk, it is subdivided into price risk, volume risk, basis risk, and liquidity risk. Price and volume risks are of superior relevance. Latter describes the necessity of a utility to buy or sell electricity volumes on the EEX if the company has forecasted an own sale to its customers of a different quantity.[62] Due to the non-storability of electricity (see 2.2), such transactions have to be done immediately and at current market prices. Therefore, on the EEX the fundamentals of the volume risk are very similar to the price risk. Hence, the most important component of the market risks is the price risk. This describes negative effects due to changes in electricity prices.[63] Because of its importance, following sections concentrate on this risk category.

Basis risks are created by the fact that the development of financial instruments, which can be used to hedge the price risks, might not exactly correlate with the price movements in the electricity market.[64] This mismatch is important, if derivates are used as risk management instruments and therefore analysed in detail in section 4.

In this thesis, the liquidity risk comprises not only the individual risk of utility illiquidity. Furthermore, in the context of the market risk it describes the risk of insufficient liquidity in the electricity market to close physical or financial trading positions without changing the market price in a negative way. This risk is of special interest, especially to individualized contracts that are fixed OTC.[65] In contrast, if there are a lot of standardized contracts or products, a single transaction does not generally have a significant influence on the pricing. Especially with trading on the EEX with standardized products, this risk is inferior due to the sound liquidity of this exchange.[66] Therefore, it could only be of special interest in the context of OTC-traded financial instruments and considered within the fourth chapter.

Important to mention is the strong interdependence within the financial risks (see above) as well as between financial and non-financial risks.[67] Even if the latter are not a field of research in this study, it is obvious that organisational weaknesses or individual mistakes (personnel risks) can reduce the quality of the utility output, such as forecasting results and hence can increase the market risk (see 4.4).

In summary, regarding the above-mentioned categories of risks, the main risk of power-trading companies can be ascribed to the dynamic and volatility of prices. To analyse these special characteristics of the electricity prices on the EEX in part 3.2, the energy exchange and the process of pricing are characterised in the following steps.

[62] Cf. Konstantin (2009), p. 61.
[63] Cf. Bergschneider/Karasz/Schumacher (1999), p. 201 & 206.
[64] Cf. Golden/Wang/Yang (2007), p. 322.
[65] Cf. Bergschneider/Karasz/Schumacher (1999), p. 206; Lehrmann (2001), p. 216.
[66] Cf. Cuaresma, et al. (2002), p. 2.
[67] Cf. Wolke (2008), p. 6.

3.1.2 Characteristics of the European Energy Exchange

Due to the introductory described worldwide trend of liberalization of energy markets, various exchanges established where energy is traded almost as any other commodity.[68] In 2002, the EEX in Leipzig arose from the merger of the power exchanges in Frankfurt and Leipzig. On 12/31/2009, the EEX was the leading energy exchange in Continental Europe with 191 trading participants from 19 countries. Besides the electricity, natural gas, coal, and CO_2 emission rights are the traded commodities on the EEX. The daily average spot market price of power is the accepted reference price for electric energy in Germany and large parts of Europe.[69]

The EEX is divided in two major business segments, the short-term physical spot market, the European Power Exchange Spot (EPEX Spot), and the futures market, the EEX Power Derivatives. In contrast to the spot market, most energy forward contracts are traded OTC.[70] However, the different types of derivates contracts are explained in more detail in section 4.2.2.

Due to the lack of the ability to store electricity, the spot market is a physical market with the necessity of physical execution of the deals that are traded in Germany as Interday or Day Ahead auctions.[71] Traders such as utility companies could use the spot market to optimise the procurement and sale of electricity in the short term. Day Ahead auctions are hourly auctions on every day of the week to trade the 24 hours of the next day. In addition, the Interday auctions enable buying and selling power with very short notice and delivery on the same trading day.[72]

On the EEX derivatives market financial futures, physical futures, and options based on the futures can be traded. The traded Phelix® Futures (Physical Electricity Index) refer to the average spot market prices of electricity for future delivery periods.[73] Hence, the daily average Phelix® is the empirical basis of following analysis. With reference to the evaluation of energy derivatives on the EEX in paragraph 4.2.2.3, a detailed description of these financial instruments is not necessary in this section.

This rudimental description of characteristics of the EXX is not conclusive. Rather, it should provide some basic information towards the pricing process on the EEX. Latter is crucial to understand dynamic and volatility of the electricity price on the EEX and therefore the central risk within the scope of this study (see 3.1.1).

[68] Cf. Meyer-Brandis/Tankov (2008), p. 503.
[69] Cf. EEX (2010a), p. 1-4.
[70] Cf. Bund-Länder-Arbeitsgruppe (2007), p. 18f; EEX (2010a), p. 29.
[71] Cf. Becker (2010), p. 398f.
[72] Cf. EEX (2010a), p. 5.
[73] Cf. EEX (2009), p. 2-4.

3.1.3 Process and Elements of Pricing on the German Electricity Market

As characterised before, the liberalisation of worldwide power markets was the beginning of a progress to establish market-based structures even in the electricity sector. Hence, the market price is the result of supply and demand.[74] Accordingly, the analysis of the pricing process had to be done by evaluating the trading structure.

The all-electronic exchange trading on the EEX is subdivided analogue to the business segments (see 3.1.2) in the consecutive inter-day trading and auctions on the EPEX Spot and the futures trade on the EEX Power Derivatives.[75] The principles of the determination of settlement prices are identical for theses products and contracts. The book situation during a defined settlement window is the basis for the pricing. This trading phase begins at a fixed point and ends with the end of the trade or the derivate contract.[76] The average price with reference character, mentioned in the previous section, is the result of supply and demand for each hour in the anonymous day-ahead auctions. The accruing price is considered for all transactions of that hour. Even if a purchaser bids a higher price, the settled price is valid for the complete ordered volume. On the other hand, a supplier gets also a higher price even if he offers his volume for a lower value.[77] The settlement price is defined as the weighted average of the mean value of the accruing exchange prices during the hourly auctions and the average mean value of the best bid and ask. If there are not enough transactions during a period, the price gets fixed via a chief trader procedure.[78]

Not the exact mathematical calculations of the pricing[79] but rather the factors that influence supply and demand are of particular interest to identify risk factors for a utility. The analysis of these parameters is essential to identify the elements of pricing (see below), which is the basis for developing spot price models in section 3.2 that should be able to anticipate movements of the electricity price.

The price of electricity supply in short- and mid-term depends fundamentally on the costs of the existing power plants. In the long-term, the cost functions of the plants are modified due to the technical progress, prices changes of fossil sources, and other environmental effects.[80] Due to the relevance of the spot market in the risk management strategy of a power-trading utility company (see 2.3), following remarks focus on a short- and mid-term time horizon. To increase the efficiency of power

[74] Cf. Huurman/Ravazzolo/Zhou (2007), p. 2.
[75] Cf. Benner (2009), p. 372.
[76] Cf. EEX (2008), p. 4.
[77] Cf. Jungbluth/Borchert (2008), p. 316.
[78] Cf. EEX (2008), p. 5-7.
[79] For details on the settlement rules, parameters, and examples regarding the determination of settlement prices on the EEX, please refer to EEX (2008), p. 10-41.
[80] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 120-122.

production considering the non-storability of electricity (see 2.2), it is economical to make use of different plants with various marginal costs. Power plants with the lowest variable costs are utilized first. Afterwards, more expensive ways to produce energy are used.[81] This arranging and using of the existing power plants regarding their costs is called merit order.[82] As illustrated in Figure 2, the price of electricity is consequently orientated on the plant with the highest marginal costs to satisfy the power demand.[83]

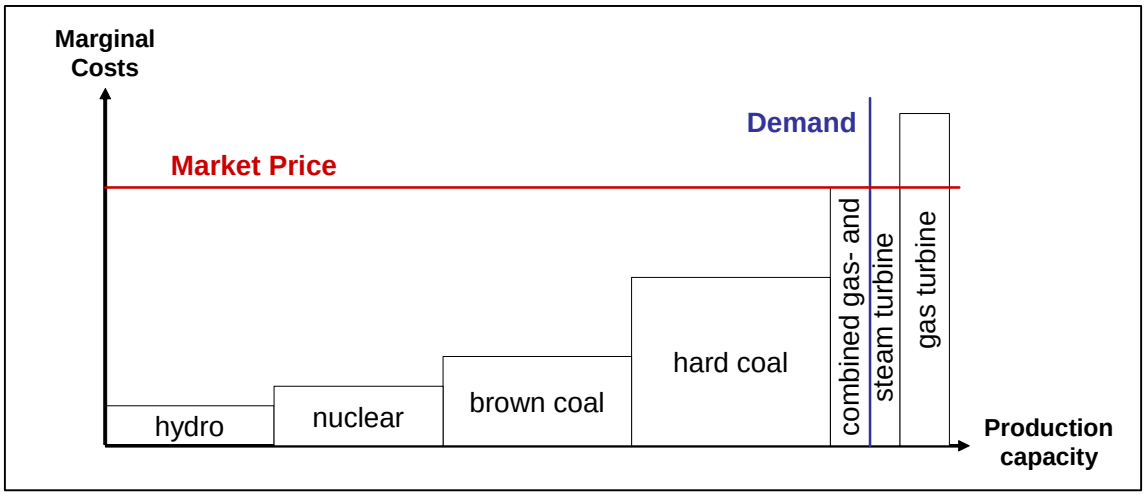

Figure 2: Request of power plants regarding the theoretical merit order[84]

On the oligopolistic German electricity market dominated by the former monopolistic ESCs, enterprises such as E.ON have a large portfolio of plants with different marginal costs. The decision regarding the selection of the plants to produce the requested power is at the ESC.[85] Therefore, with a structured retention of producing capacities a market-dominating ESC could influence the pricing.[86] This market structure is an immense risk for a utility of unforeseeable and rising power prices.

Another risk factor, which cannot be influenced by the power-trading utility, is the price of fossil sources such as coal or crude oil. 58% of the power production 2009 was based on coal, oil, and natural gas.[87] Hence, the price of electricity is also strongly dependent of the prices of fossil sources that are used in conventional thermal plants.[88] In the context of fossil sources the problem of greenhouse gas emissions while their processing is important to mention.[89] On basis of the Kyoto Protocol and the

[81] Cf. Knieps (2007), p. 75.
[82] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 120.
[83] Cf. Jahn (2008), p. 300.
[84] Source: Haucap, et al. (2009), p. 34, No. 48.
[85] Cf. Jahn (2008), p. 299.
[86] Cf. Becker (2010), p. 404.
[87] Cf. BDEW – Bundesverband der Energie und Wasserwirtschaft (2010), on the internet: http://www.bdew.de/bdew.nsf/id/DE_Brutto-Stromerzeugung_2007_nach_Energietraegern_in_Deutschland?open&l=DE&ccm=450040020, access: 07/13/2010, 11:52 am.
[88] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 117.
[89] Cf. Möller (2008), p. 5.

corresponding EU directive, the German Federal Government implemented a profound legal framework. Its main instrument is the European emissions trade. This market-based instrument defines caps of maximum CO_2 emissions for the energy sector as well as for other branches.[90] Companies that participate in the trading have two general options: Buy emissions rights or reduce the CO_2 output, for instance with investments in modern technology.[91] However, both options effect additional expenditures, can increase the costs of power production, and therefore in the end influence the pricing of electricity as well.

Moreover, it is predictable that the fluctuation on the supply side will arise even if more market-based structures can be established. The Renewable Energy Sources Act in Germany (EEG) claims to increase the share of renewable energies from 16% in 2009[92] to 30% in 2020.[93] In Germany, wind energy plants provide a main part of renewable energy. Nowadays, a reliable wind forecast is not possible for more than a few hours.[94] This unpredictable fluctuation of the production based on wind or solar energy will certainly also reflect in the volatility of the EEX market price.[95] Moreover, renewable energies have a direct influence on the pricing and not via the traditional merit order (see Figure 2, p. 13). Due to the guaranteed feed-in-tariff renewable energy sources do not follow the merit order but enjoy the prior feed-in in the German transmission network.[96] This guarantee certainly influences the power price.

In addition to these difficulties on the supply side, which still today could not be solved by different political interventions (see 2.1),[97] forecasting the consumption of electricity is also very difficult. Various elements influence demand and distribution of electrical energy. Multiple overlapping seasons have a solid influence on the demand and hence the pricing.[98] Due to day-to-day, seasonal, cyclical, or weather variations, the power prices fluctuate enormous especially in the short term.[99]

Furthermore, it is important to mention that weather is an uncontrollable factor, which is very difficult to forecast.[100] As described above, this dynamic variable is a significant

[90] Cf. Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU) (2006), p. 4-6.
[91] Cf. Spangardt/Meyer (2005), p. 219.
[92] Cf. Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (BMU) (2010), p. 20.
[93] Cf. § 1, II EEG.
[94] Cf. Neubarth, et al. (2006), p. 42.
[95] Cf. Hilpold (2009), p. 388; Techert, et al. (2009), p. 331.
[96] Cf. Sensfuß/Ragwitz/Genoese (2008), p. 3086.
[97] There are still deficits in the realization of the EnWG. Especially within the implementation of the four kinds of unbundling, according to §§ 6-10 EnWG that are seen as basic factors to assure a fair competition, the BKartA assesses an insufficient progress (cf. Haucap, et al. (2009), p. 9, No. 33; Benner (2009), p. 371-377; Jahn (2008), p. 297-314; and others).
[98] Cf. Escribano/Peña/Villaplana (2002), p. 4.
[99] Cf. Al Janabi (2009), p. 16f.
[100] Cf. Golden/Wang/Yang (2007), p. 319f.

factor influencing the supply for example through the production of wind energy plants as well as the demand for electricity.[101]

Summarizing this section in Figure 3, many different factors influence the market prices on the EEX and the previous statements only provide an overview.

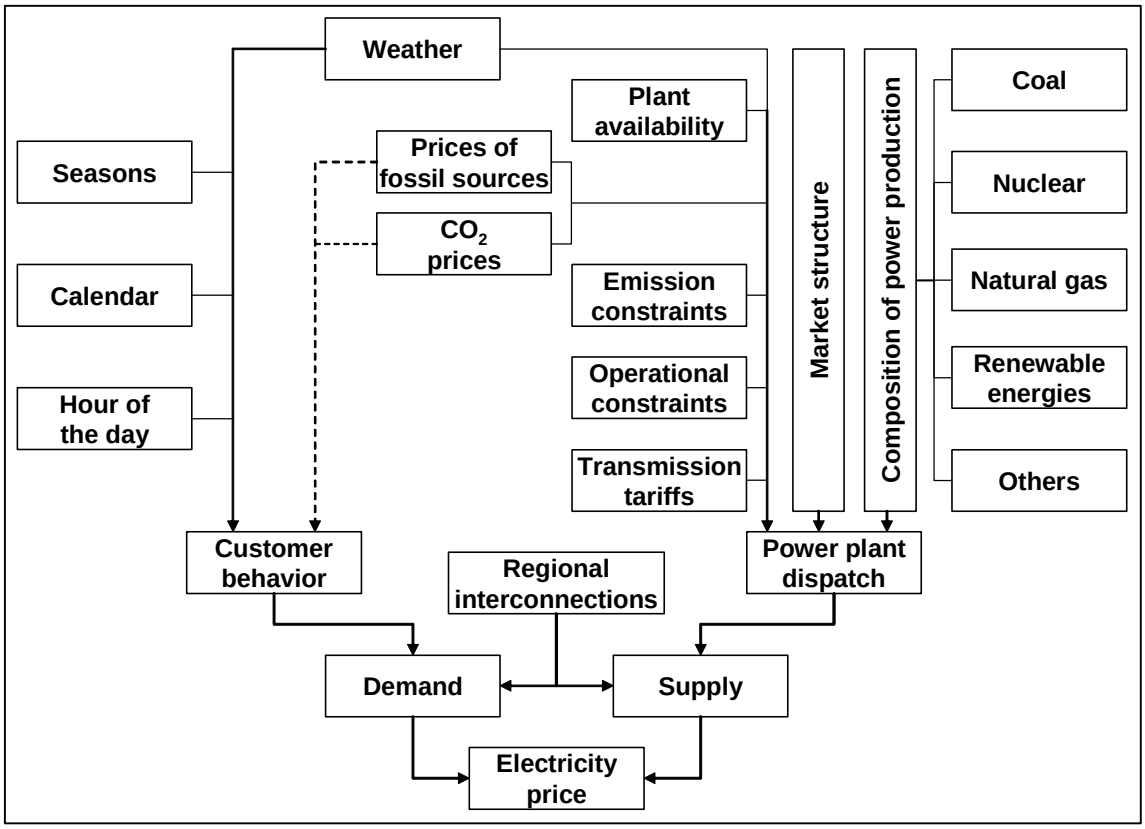

Figure 3: Fundamental risk factors in power markets[102]

Finally, it is essential to consider that energy markets are very sensitive to external shocks to explain the pricing on the German electricity market. Price spikes are a result of the non-storability of electricity, because there are no sufficient power reserves for a physical compensation of the shocks (see 2.2). Supply-sided shocks accrue maybe due to an unplanned breakdown of a large power plant. Demand-sided shocks might be caused by abnormal weather conditions such as a heat weave with a high load of refrigeration or air-conditioning systems. In addition, failures in the market mechanism such as price manipulation as indicated before can cause immense price fluctuations.[103] This rising volatility of electricity prices causes a high interest in reliable economic models to forecast the pricing of electric energy.[104] The increasing dynamic of the electricity price and models to analyse it are evaluated within the next section.

[101] Cf. Ross/Kolos/Tompaidis (2006), p. 628.
[102] Source: Burger/Graeber/Schindlmayr (2007), p. 133.
[103] Cf. Cuaresma, et al. (2002), p. 3.
[104] Cf. Cuaresma, et al. (2002), p. 1.

3.2 Evaluation of Market Price Dynamic and Volatility

3.2.1 State of the Art

AS mentioned before, an improvement of models to forecast power load becomes more important. Accurate forecasts reduce environmental pollution and increase efficiency.[105] Supply and demand of power regress towards a long-term equilibrium, but are in short-term subject to fluctuations.[106] Therefore, short-term load forecasting models are in the focus of former and the following analysis.

First approaches aimed at the expected degree of capacity utilisation of electric grids. Ackerman (1985) considered hourly power loads in three models. As one of his results, the first order autoregressive (AR) process and the extension of the AR with a moving average (MA) seem to be inferior to a simple AR model.[107] Based on a theorem of Granger (1987), which connects methods of AR, MA, and error correction,[108] Engle, Granger and Hallman (1989) developed a co-integration approach to forecast monthly electricity sales.[109] To capture the characteristics of the pricing process in linear models such as autoregressive moving average models (ARMA) processing data chronologically is the most common attempt in time series analyses.[110]

In the following, Ramanathan, Granger, and Engle (1995) adopted a two-step model. Quickly varying variables such as temperature or the time of the day are factors of the first part. The second step adds slowly changing parameters such as demography or income.[111] In another approach, Ramanathan, Engle, and Granger (1997) developed a multi regression model. Not one ongoing time series, but the modelling of separate equations for each hour of the day and splitting weekdays and weekends is the basic idea. The accruing 48 models consider variables such as the day, the temperature as a factor of demand, and a linear trend of increasing demand as well as the load of the grid or the five previous documented errors.[112]

Alternatively, Bollerslev and Ghysels (1996) extended the ARMA model by seasonal effects for a better characterization of financial markets volatility. In its rudimental form, periodic generalized autoregressive conditional heteroscedasticity models (P-ARCH) use seasonally autoregressive coefficients to consider fluctuations.[113] This seems so be a promising attempt, especially for proposes of volatile energy markets. Therefore,

[105] Cf. Malki/Karayiannis/Balasubramanian (2004), p. 157.
[106] Cf. Al Janabi (2009), p. 16.
[107] Cf. Ackerman (1985), p. 33-42.
[108] Cf. Engle/Granger (1987), p. 251.
[109] Cf. Engle/Granger/Hallmann (1989), p. 45-62.
[110] Cf. Aslanargun, et al. (2007), p. 29.
[111] Cf. Ramanathan/Granger/Engle (1995), p. 131-157.
[112] Cf. Ramanathan, et al. (1997), p. 163-164.
[113] Cf. Bollerslev/Ghysels (1996), p. 140.

Robinson (2000) used a nonlinear time-series model, the smooth transition autoregressive model (STAR), to examine characteristics of spot market prices of electricity. Even if the study does not analyse the possibility to forecast electricity prices with nonlinear models, it sensitized for occurring problems due to the technical difficulties.[114] On a comparable basis, Escribano, Peña, and Villaplana (2002) developed a general strategy to analyse daily electricity spot market prices.[115] The results of this study are crucial to characterizing the pricing process on the EEX, but the difficulties of forecasting with nonlinear models remain.

Cuaresma, et al. (2002) transferred the idea of separating single hours to electricity spot market prices on the basis of EEX data from June 2000 to October 2001. The study examines univariate AR, ARMA, and unobserved components models. Cuaresma, et al. eliminates price spikes, which are results of supply- or demand-sided shocks, via a recursive filter. The study shows that an hour-by-hour approach and eliminating spikes can lead to better forecasts of power prices. An additional result is the assumption, that models that could reproduce and describe facts better, must not produce better forecasts. Hence, forecasting results, even of computational complex multi-step forecasts in nonlinear models, will not necessarily be more accurate.[116]

Based on a similar argumentation, Weron and Misiorek (2005) evaluated simple ARMA models. Their study tries to improve the accuracy of electricity price forecasts. It considers that price swings are not as pronounced as load fluctuations. It incorporates exogenous variables, like loads or plant data, and takes unexpected psychological and sociological factors into account that could lead to spike prices. In their conclusion, they also confirm that complex multi-parameter models deliver only slightly better or comparable forecasting results than parsimonious stochastic models.[117] Afterwards, Huurman, Ravazzolo, and Zhou (2007) also presumed that ARMA models could provide the best forecasting results for power prices. The study tries to improve these forecasts by including weather variables in established models of electricity prices.[118]

Based on this analysis, an adequate model to forecast electricity prices must be able to consider movements of the market price regarding seasonal, weekly, and daily rhythms.[119] In addition, the model should display a long-term development as well as the typical short-term price jumps.

[114] Cf. Robinson (2000), p. 527-532.
[115] Cf. Escribano/Peña/Villaplana (2002), p. 1-34; Koopman/Ooms/Carnero (2005), p. 2f.
[116] Cf. Cuaresma, et al. (2002), p. 1-14.
[117] Cf. Weron/Misiorek (2005), p. 133-141.
[118] Cf. Huurman/Ravazzolo/Zhou (2007), p. 3.
[119] Cf. Weron/Misiorek (2005), p. 133f.

3.2.2 Adequate Model to Forecast Dynamic and Volatile Electricity Prices

With reference to the previous part and the scope of this thesis, a stochastic spot price model could provide sufficient forecasts. Furthermore, it is analytically tractable for managing market price risks of electric energy even if it does not fit perfectly to the characteristics and movements of the real electricity prices seen on the EEX (see 3.2.3). Approaches that consider theses requirements are for example Jump-Diffusion models. Jump-Diffusion processes base on Merton (1976), who considered a mixture of 'normal' price variations and 'abnormal' jump processes.[120] In extension, Johnson and Barz (1999) introduced the mean-reversion after a jump.[121]

a) Necessary Components

Replicating statistical properties of spot prices with the ultimate intention to evaluate derivatives is a common feature of these stochastic models.[122] Hence, it is also crucial in this context, because it is important to develop adequate risk management strategies of utility companies in chapter 4 to hedge electricity price fluctuations. Generally, in its standard form such a model consist of two parts.[123]

- A deterministic function of time $f(t)$ takes the cycles and seasonality of electricity markets into account. [124]
- A diffusion stochastic process X regresses towards a long-term equilibrium (see 3.2.1)[125] and follows a mean reversion process.[126]

These assumptions lead to a simple basic equation to examine the spot price (P_t).[127]

$$P_t = f(t) + X_t \tag{I}$$

Representing the seasonality with a linear trend via a sinusoidal function is a common approach, but not completely sufficient for purposes of the German electricity market. On the EEX, spikes occur in winter and in summer seasons. Such spikes are considered in so-called regime-switching models. In case of the EEX, a spike regime with a different stochastic process should be added to the base regime.[128]

Therefore, the mean-reverting model has to include seasonality and spikes to fulfil the requirements of this paper,[129] because hedging risks, which are results of spike prices,

[120] Cf. Merton (1976), p. 127.
[121] Cf. Johnson/Barz (1999), p. 3-21.
[122] Cf. Weron/Misiorek (2005), p. 134.
[123] Cf. Janczura/Weron (2010), p. 6.
[124] Cf. Lucia/Schwartz (2002), p. 17.
[125] Cf. Al Janabi (2009), p. 16.
[126] Cf. Meyer-Brandis/Tankov (2008), p. 514.
[127] Cf. Lucia/Schwartz (2002), p. 17.
[128] Cf. Weron/Bierbrauer/Trück (2004), p. 41-43.
[129] Cf. Kluge (2006), p. 27.

is a central motive of risk management in a power-trading utility (see 2.3). To consider such spikes, a third part has to be added to formula (I).

– The presence of price jumps is a fundamental feature of electricity prices.[130] Hence, including a spike process Y to forecast electric prices is indispensable.[131]

Lucia and Schwarz (2002) implemented such a model to describe spot market power prices with focus on the Nordic Power exchange.[132]

$$P_t = f(t) + X_t + Y_t \qquad \text{with} \quad t \in \mathbb{N} : 1 \leq t \leq N \qquad \text{(II)}$$

After capturing market conditions with an AR structure, the model could explain price behaviour.[133] Formula (II) provides a variation of the equation of Lucia and Schwarz. Spot market prices at date t (P_t) could be analysed with N = 365 in a model of daily respectively with N = 8.760 in a model of hourly prices. The term $f(t)$ represents a deterministic part[134] discussed in the following step b). Afterwards, the stochastic mean-reverting components X_t and Y_t are analysed in section c).

b) Deterministic Component

To consider the typical German seasonality of higher power demand within the colder months from September to March (see appendix B, Figure 17, p. 83),[135] the model has to differentiate between various seasons. A detailed analysis confirms that EEX data contains seasonality (see Figure 4, p. 22).[136] Fluctuations in power demand in Germany like in other countries depend on the time of the day, the day of the week as well as of the season of the year.[137] The existence of different load profiles is also confirmed by the different kind of derivatives that are traded on the EEX (see 4.2.2.3), which are differentiated according peakload, off-peak, and baseload timeframes.[138] Hence, the deterministic function is the sum of those different overlapping kinds of seasonality: Daily f_D, weekly f_W, and monthly f_M seasons.[139]

$$f(t) = \alpha_0 + f_D(t) + f_W(t) + f_M(t) \qquad \text{with} \quad t \in \mathbb{N} : 1 \leq t \leq N \qquad \text{(III)}$$

The absolute term α_0 describes the baseload, which is indifferent of any fluctuations and represents the minimum of power demand. Usually, this level can only be achieved

[130] Cf. Meyer-Brandis/Tankov (2008), p. 508.
[131] Cf. Weron/Bierbrauer/Trück (2004), p. 43f.
[132] Cf. Lucia/Schwartz (2002), p. 22.
[133] Cf. Weron/Misiorek (2005), p. 136f.
[134] Cf. Kluge (2006), p. 27.
[135] Cf. Grichnik/Vortmeyer (2002), p. 388.
[136] Cf. Meyer-Brandis/Tankov (2008), p. 526.
[137] Cf. Wilkens/Tanev (2006), p. 300.
[138] Cf. EEX (2010b), p.1f.
[139] Cf. Escribano/Peña/Villaplana (2002), p. 4

in the night.[140] The variable f_D considers movements of individual hours or blocks of one day with hourly prices such as they are traded in day ahead auction on the EPEX Spot.[141] Thus, the variable f_W determines fluctuations within a week. This considers especially that, in general, prices on weekends are lower than on working days (see appendix B, Figure 16, p. 83).[142] Finally, f_M represents the seasons of the year (see appendix B, Figure 17, p. 83).[143]

To capture the characteristic of interleaving seasons,[144] using overlapping sinus and cosines oscillations is an adequate procedure to take into consideration weekly and monthly fluctuations in the first step. It is obvious, in a model with N = 365 to analyse daily spot market prices, the inter-daily fluctuations are not relevant. Hence, for N = 365 it is $f_D \equiv 0$ and $f(t)$ to be the form

$$f(t) = \alpha_0 + f_W(t) + f_M(t) = \alpha_0 + \sum_{i=1}^{6} a_i \cos(2\pi y_i t) + b_i \sin(2\pi y_i t) \qquad \text{(IV)}$$

with $y_1 = 1$, $y_2 = 2$, and $y_3 = 4$ for the yearly seasons portioned into twelve months and $y_4 = 365 / 7$, $y_5 = 2 * 365 / 7$ and $y_6 = 4 * 365 / 7$ for weekly seasonality. [145]

Theoretically, it is possible to add a similar equation for the inter-daily fluctuation in the next step, but regarding the EEX, hourly repeating variations does not make sense. In general, not hourly fluctuations, but a separation in a peakload time from 9 am to 9 pm and an off-peakload from 9 pm to 9 am could represent inter-daily variations.[146] Therefore, it seems to be an adequate approach, to add to the formula (IV) a factor β to consider the higher demand of power within the peakload phase in a model with N = 8.760, whereas the β-factor is only valid in the daytimes from 9 am to 9 pm.

$$f_D(t) = \beta_{[9-21]} \qquad \text{(V)}$$

Summarizing the previous statements, the deterministic part with N = 8.760 and $t \in \mathbb{N} : 1 \leq t \leq N$ for a basic hourly spot price analysis is in the form

$$f(t) = \alpha_0 + \beta_{[9-21]} + \sum_{i=1}^{6} a_i \cos(2\pi y_i t) + b_i \sin(2\pi y_i t) \qquad \text{(VI)}$$

with the above-mentioned input factors for *y*.

[140] Cf. Jahn (2008), p. 299.
[141] Cf. EEX (2010a), p. 6.
[142] Cf. Grichnik/Vortmeyer (2002), p. 387; Huurman/Ravazzolo/Zhou (2007), p. 5.
[143] Cf. Meyer-Brandis/Tankov (2008), p. 526.
[144] Cf. Escribano/Peña/Villaplana (2002), p. 4
[145] Cf. Kluge (2006), p. 29.
[146] Cf. EEX (2010b), p. 1.

c) Stochastic Components

Two stochastic components are the addition to the deterministic model in order to create an adequate model for forecasting electricity prices. As mentioned in part a), the first stochastic component describes a diffusion process that allows the mean reversion to a base level.[147] As a basic concept of pricing, the Brownian Motion describes a constant and stationary distributed pricing process.[148]

$$dX_t = -\varepsilon X_t dt + \sigma X_t dW_t \qquad \text{with} \quad \varepsilon \in \mathbb{R}_+ \qquad \text{(VII)}$$

In formula (VII) corresponding to Lucia and Schwartz (2002), ε determines the speed of the mean reversion process of X_t.[149] The standard variance of the Brownian Motion is σ. This process starting with $X_0 = 0$ and $t \geq 0$ is known as Wiener Process.[150]

Due to its consistency, one inherent disadvantage of a standard Wiener Process is its inability to mimic jumps.[151] Therefore, the remaining second stochastic part deals with the consideration of price spikes to encounter this problem. To achieve the regression of a long-term mean,[152] spot prices also have to tend back after a spike to a normal level. Hence, even the spike process Y has a mean-reverting part that causes the return to the long-term equilibrium, but with a different mean-revision rate η.[153]

$$dY_t = -\eta Y_t dt + J_t dN_t \qquad \text{with} \quad \eta \in \mathbb{R}_+ \qquad \text{(VIII)}$$

The normal-distributed jump component J_t in formula (VIII) expresses the sizes of the jump at date t.[154] N_t denotes a poisson process with the intensity λ that expresses the frequency of the jumps.[155]

The deviation in two different stochastic elements allows creating different mean-reversion rates ε and η.[156] That enables this model to take the high dynamic and volatility of electricity prices on the EEX[157] into account. For purposes of this thesis not an exact analytical evaluation but a general assessment regarding accuracy and reliability of this approach to forecast electricity spot market prices is necessary (see 3.2.3) to ensure a suitable basis for further steps in the risk management of a utility.

[147] Cf. Meyer-Brandis/Tankov (2008), p. 514.
[148] Cf. Merton (1976), p. 126.
[149] Cf. Lucia/Schwartz (2002), p. 17.
[150] Cf. Franke/Härle/Hafner (2004), p. 57 & 64.
[151] Cf. Kluge (2006), p. 25.
[152] Cf. Al Janabi (2009), p. 16.
[153] Cf. Bierbauer, et al. (2007), p. 3466f.
[154] Cf. Lee/Cheng (2007), p. 905.
[155] Cf. Bierbauer, et al. (2007), p. 3466; Kluge (2006), p. 25.
[156] Cf. Meyer-Brandis/Tankov (2008), p. 514.
[157] Cf. Ockenfels/Grimm/Zoettl (2008), p. 73f.

3.2.3 Accuracy and Reliability of Electricity Prices Forecasts

To ensure the usability of the forecasting model developed before, the accuracy and reliability of this calculation gets evaluated on basis of empirical data of the EEX.

Basis of the analysis is the daily Phelix® baseload monthly index. This reference price of power (see 3.1.2) is the weighted average of all 24 spot hour prices of one day.[158] The data comprises 2,088 observed trading days (t) from 01/01/2002 to 12/31/2009. A minimum Phelix® of 3.12 EUR/MWh on 05/01/2003 (t = 348) and a maximum daily average price of 114.06 EUR/MWh on 12/01/2005 (t = 1.023) could thereby express the extreme price volatility on the EEX (see appendix A, Figure 13, p. 80).

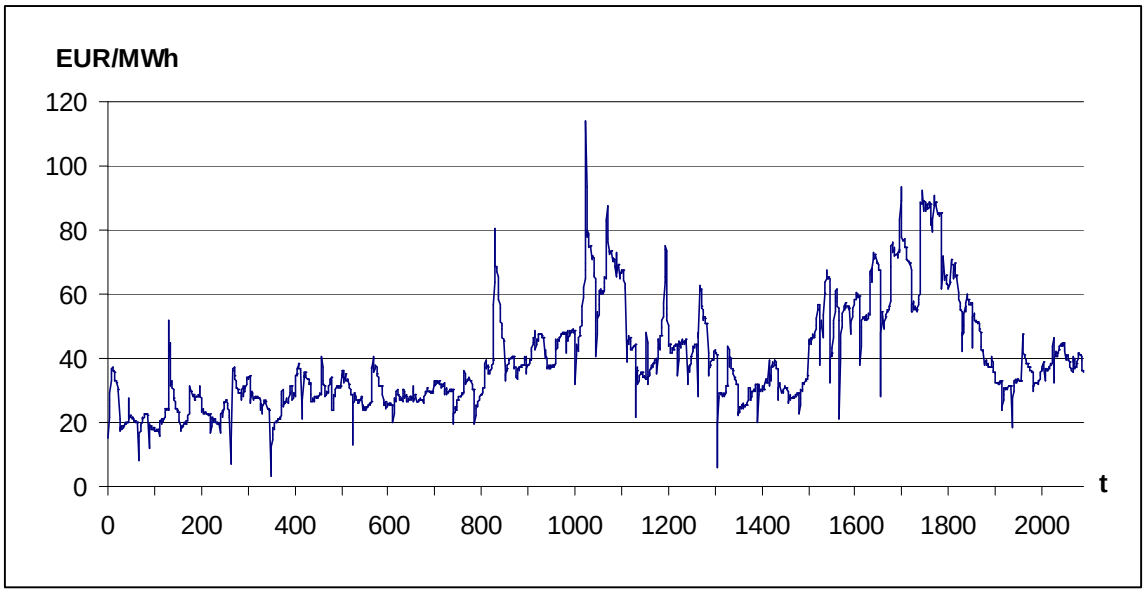

Figure 4: Phelix® baseload monthly index 01/01/2002 - 12/31/2009[159]

As mentioned in part 3.2.2, an analysis of average daily prices does not need to consider inter-day fluctuations. Figure 4 confirms the basic assumption visually, sinusoid functions can approximate the repeating seasons by using formula IV (p. 20) with an appropriate accuracy.[160] Obviously, Figure 4 could confirm the hypothesis of a long-term trend regressing to equilibrium (see 3.2.1).[161] Furthermore, the economic development seems to be an important factor, which influences the power demand[162] and hence, in liberalized electricity markets with market-based structures the price (see 3.1.3). Business cycles are visibly influencing the electricity price. The worldwide financial and economic crises, which started with the sub-prime crisis in the USA, lead

[158] Cf. Bierbauer, et al. (2007), p. 3469.
[159] Source: EEX via DataStream (access: 06/03/2010), *local link*: “Wittenberg; Appendix A - Phelix _MonthBase.xls”, table: Charts.
[160] Cf. Weron/Bierbrauer/Trück (2004), p. 40f.
[161] Cf. Al Janabi (2009), p. 16.
[162] Cf. Ramanathan, et al., p. 163.

to a decreasing demand for electricity.[163] Due to the dependence of the spot market price on the EEX on supply and demand,[164] the price of electricity also decreased between the trading days 1,700 and 1,900 from autumn 2008 to spring 2009.

Looking at the graph, the existence of spikes cannot be denied. Even if the stochastic elements of the model are not able to produce an exact forecast of spikes, because such jumps are element of mostly unforeseeable supply- and demand-sided shocks (see 3.1.3), they can assess the process of the arrival of a spike. This could lead to higher forecast accuracy.[165]

In conclusion, differences between real and forecasted electricity spot market prices are unavoidable, but the implementation of a learning system could improve the accuracy of forecasts.[166] A successive correction of the predicted prices based on former experiences by connecting current to past prices and current to previous errors in the forecast can help to improve the accuracy. Here, artificial neural network models (ANN) are a promising field of research,[167] but they are going beyond the scope of this study. Even if they can deliver more accuracy forecasting results, the general strategic concept of a utility company's risk management process remains the same. Therefore, ANN models are not of further interest in the context of this thesis.

Summarizing, even if there are the above-mentioned difficulties in accuracy, the model can capture stylize facts of spot market prices on the EEX at least to an acceptable degree[168] to develop an efficient risk management strategy.

3.3 Measurement of Market Price Risks

3.3.1 Portfolio Specification of a Power-Trading Utility Company

After identifying relevant risks of a portfolio and a possibility to analyse the main risk of fluctuating power prices on the EEX[169], it is necessary to quantify these effects for a utility.[170] Based on accurate electricity price forecasts, producers such as E.ON or RWE can develop bidding strategies to maximize their profit, while utility companies without own production capacities can allocate between long-term bilateral contracts and short-term arrangements on the EPEX Spot to enhance their portfolio return.[171] In

[163] Cf. Janczura/Weron (2010), p. 6.
[164] Cf. Huurman/Ravazzolo/Zhou (2007), p. 2.
[165] Cf. Cuaresma, et al. (2002), p. 13f.
[166] Cf. Zhou, et al. (2006), p. 188.
[167] Cf. Georgilakis (2007), p. 708.
[168] Cf. Benth/Kallsen/Meyer-Brandis (2007), p. 168.
[169] Cf. Fricke (2006), p. 37.
[170] Cf. Pschick (2008), p. 76.
[171] Cf. Zhou, et al. (2006), p. 187.

this section, the evaluation of market price risks should enable a risk assessment of such a portfolio in form of a money-amount.

Even if utility companies try to minimize this risk via diversification of their service portfolios with new offers such as telecommunications, energy supply remains a main factor and therefore of central interest.[172] However, before choosing a target-aiming model, in the first step it is crucial to characterize the typical structure of the energy-related part of the portfolio of a power-trading company. This includes a set of contracts for delivery and purchase of power as well as contracts of financial nature.[173]

The sales side of the electricity-related portfolio's value depends mostly on the number of customers and their power demand. Generally, the pool of end costumers can be divided in two mayor groups with different demand structures: Industrial versus household customers (see appendix B, Figure 14, p. 81).[174] The supply of end-customers with electric energy through utility companies usually bases on open contracts with fixed prices for the period of agreement. Neither the quantity nor the date of delivery is set when the contracts are concluded. Only the individual demand of the customer is relevant.[175] Due to this of volume and date independent contracts, the market price risk and the volume risk due to differences between forecasted and real consumption remain at the supplier and are therefore in the focus of this thesis. To fulfil delivery obligations, utility companies have to buy missing volumes in short-term on the EPEX Spot. Because of the inability to storage electricity (see 2.2), not needed power has to be sold on the spot market at current conditions. In addition, such contracts have also an inherent risk regarding the period of agreement. Besides realized gains and losses of spot market transactions, also calculative gains and losses accrue. Even in case of decreasing or increasing wholesale prices on the EEX, a utility company still has to sell the power at contracted higher respectively lower prices to end-customers.[176] This clarifies the importance of contracting periods. On liberalized energy markets contracting periods are decreasing,[177] which is one factor of the increasing importance of managing before-mentioned risks.

To fulfil the commitments of such a service portfolio, utility companies have to provide the electricity at the right time, place, and volume regarding the customer's demands.[178] Generally, they can procure the power at short notice on the EEX or via

[172] Cf. Wildemann (2009), p. 17.
[173] Cf. Fleten/Wallace/Ziemba (2002), p. 71.
[174] Cf. von Hirschhausen/Cullmann/Kappeler (2006), p. 2563.
[175] Cf. Kolks (2003), P. 298.
[176] Cf. Kremp/Rosen (2002), p. 48f.
[177] Cf. Konstantin (2009), p. 65.
[178] Cf. Eydeland/Wolyniec (2003), p. 10.

long-term delivery contracts with ESCs. Hence, the above-described price and volume risks in the relationship of a utility and its end-customers are similar to the risks between the utility company and the electricity supplier.[179]

To avoid an accumulation of these risks or even to create a situation where the chances and risks of sales and procurement side compensate each other, the power-trading company can try to synchronize the contracts of their entire portfolio (see 4.2.1). This requires reliable power forecasts with the difficulties considered in 3.2. For the purpose of this thesis, a fictive example that is developed and explained in appendix B represents the utility's portfolio. This contains agreements with different customer groups on the sales side and the ESC on the procurement side. Depending on the kind of customer, different power prices in EUR/kWh are contracted.[180] Based on historical information and forecasting models (see 3.2), the average consumption, baseloads per customer group, and their typical demand structures are estimated. This enables a daily forecast of the potential progress of the power consumption for a coming year with t = 365 (see appendix B). Knowing the volume and the time of the needed electricity, the utility can create its portfolio for the power supply side with different kinds of contracts as illustrated in Figure 5 (see also 4.2.1).[181]

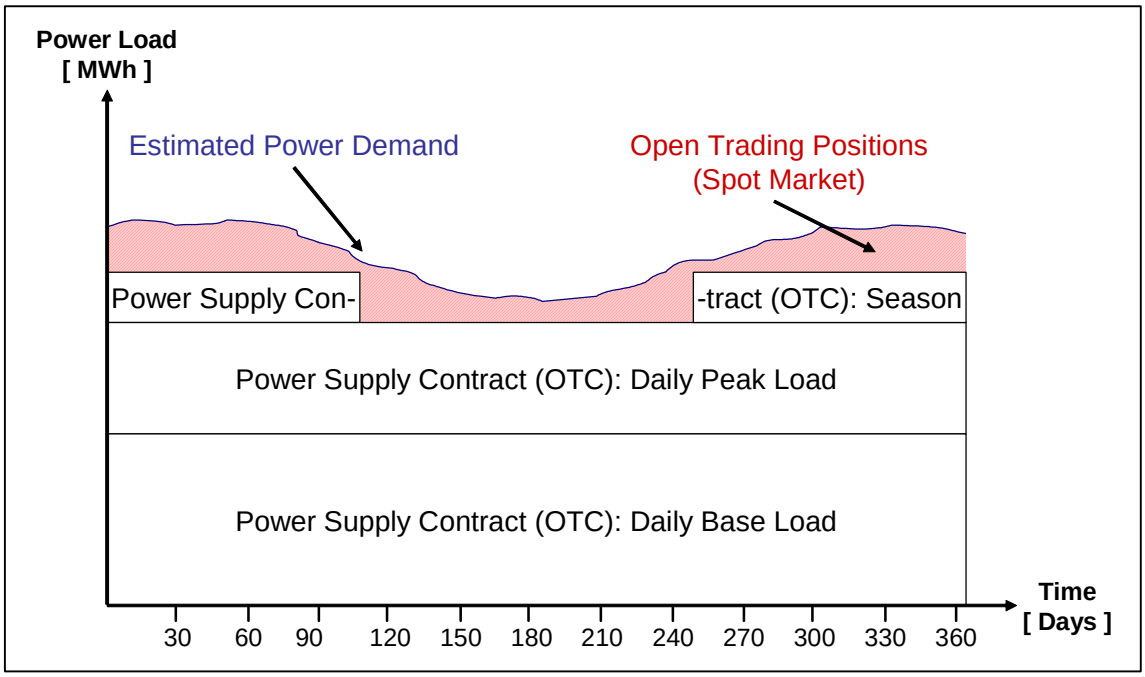

Figure 5: Scheme of a utility's power-supply portfolio[182]

Summarizing, a perfect synchronization of sales and procurement contracts seems to be impossible and methods to quantify the remaining risks are necessary to develop a

[179] Cf. Konstantin (2009), p. 61.
[180] Cf. Ross/Kolos/Tompaidis (2006), p. 628.
[181] Cf. Fleten/Wallace/Ziemba (2002), p. 73.
[182] Source: Eßer-Scherbeck (1999), p 8; with reference to appendix B.

risk management strategy. Hence, the third part of the portfolio, the financial contracts, is important to close this cap between the contracted prices and the spot prices to reduce the total portfolio risk.[183] Figure 5 illustrates this cap as the red-shaded open trading positions. Financial contracts such as forwards or options are indispensable in modern risk management and therefore analysed in detail in chapter 4.

To choose a risk management tool for the quantification of the risks described above, it is likely to be oriented on the banking sector due to its great experience with derivatives and hedging market price risks.[184] Thereby, the concept of Value-at-Risk (VaR) has become especially prevalent in economical practice and the standard international approach to measure market risks.[185] Furthermore, its popularity as a field of research and its wide distribution as a risk measurement tool in the energy-trading sector[186] is the reason for particularly focussing on it within the following part of this thesis.

3.3.2 The Concept of Value at Risk (VaR)

3.3.2.1 Definition

To quantify the risk of utility's portfolios, in the first step it is essential to identify the risky positions within such a portfolio. Therefore, it is necessary to differentiate between closed and open trading positions (see Figure 5, p. 25). Only open positions react on fluctuations of power prices and are therefore of special interest in this section.[187] To asses such open positions, Marking-to-Market (MtM) is a common approach by confronting the contracts of the utility's portfolio with true market prices.[188] Hence, MtM describes the evaluation of such an asset according to the price it could realize if sold on the market. To illustrate MtM, it is suggested that on 07/01/2010 a utility fixes a contract to sell 120 MWh (24 h * 5 MWh) for 35 EUR/MWh on 12/01/2010. On the fixing date, the utility pays an initial margin of EUR 1,000 to a brokers margin account. This account is adjusted at the end of each trading day to average market prices. If on 08/01/2010 the Phelix® is at 38 EUR/MWh the utility would realize a loss of EUR 360 (-3 EUR/MWh * 120 MWh) because it still has the deliver the power at 35 EUR/MWh. Hence, the margin account balance is at EUR 640. In case of a decreased market price to 32 EUR/MWh on 09/01/2010 the margin accounts shows the balance of EUR 1,360, which includes the utility's calculative profit until that date of EUR 360.[189]

[183] Cf. Benner (2009), p. 372.
[184] Cf. Pschick (2008), p. 127.
[185] Cf. Harper/Keller/Pfeil (2000), p. 6; Holtdorf/Rudolf (2000), p. 122.
[186] Cf. Al Janabi (2009), p. 22.
[187] Cf. Pschick (2008), p. 127.
[188] Cf. Acerbi/Scandolo (2007), p. 5.
[189] Cf. Hull (2009), p. 26f.

On the basis of this above shortly described measurement of the risk,[190] the concept of VaR can be used to control these open positions.[191] For the purpose of this thesis, the target is to focus on a definition, which generally refers to the work of JP Morgan. The company introduced the concept of RiskMetrics™ that provides estimates of VaR as a tool for professional risk management in economical practice in 1994.[192]

Giving the portfolio with the identified value and variations in time that depend on several risk factors, Knobloch (2005) accordingly defines the VaR as "(…) the negative difference of the future portfolio value and its present value that will not be exceeded at a confidence level of $1-\alpha$ at the end of a predefined (..) period of length (..)."[193] For example, the loss of the utilities portfolio of open positions using MtM is not exactly predictable but the output due to price fluctuations could be seen as a random variable. If the confidence level is at 99% ($\alpha = 0{,}01$), this 1%-quantile represents the loss as a negative VaR in form of a money amount, which would not be exceeded with a probability of 99% within the defined period.[194] Besides this 1%-quantile, which is attributable to banking regulations, confidence levels of 95% or 90% could be acceptable for different purposes.[195]

Summarizing, the VaR describes the probability of losses but not their dimension as a function of the two parameters time (t days) and confidence level ($1-\alpha$).[196] Its result is a single understandable key figure. This is a main reason for its wide usage also in non-financial firms such as utilities.[197]

3.3.2.2 Methods to Estimate the VaR

Since its implementation and especially since the establishment of the VaR concept within the Basel II agreements as a standard risk measurement tool[198] many models to calculate the VaR have arisen. Generally, they are classified into local-valuation, the variance-covariance approach, and full-valuation methods.[199] This differentiation reflects the two main approaches of estimating the VaR. The local-valuation method refers to an analytical approach whereas full-valuation methods base on simulation.[200]

[190] For a MtM calculation of the fictive utility's portfolio developed in 3.3.1 and the corresponding appendix B please refer to appendix E.
[191] Cf. Pschick (2008), p. 128.
[192] Cf. Dunis/Ho (2005), p. 34; Morgan Guaranty Trust Company (1996), p. 165.
[193] Cf. Knobloch (2005), p. 100.
[194] Cf. Scharpf (2006), p. 50.
[195] Cf. Prokop (2008), p. 469; Scharpf (2006), p. 50.
[196] Cf. Hull (2009), p. 451.
[197] Cf. Basak/Shapiro (2001), p. 371.
[198] Cf. Bank for International Settlements (2004), p. 73, No. 346.
[199] Cf. Jorion (2007), p. 247.
[200] Cf. Hull (2009), p. 451; Hager (2004), p. 103.

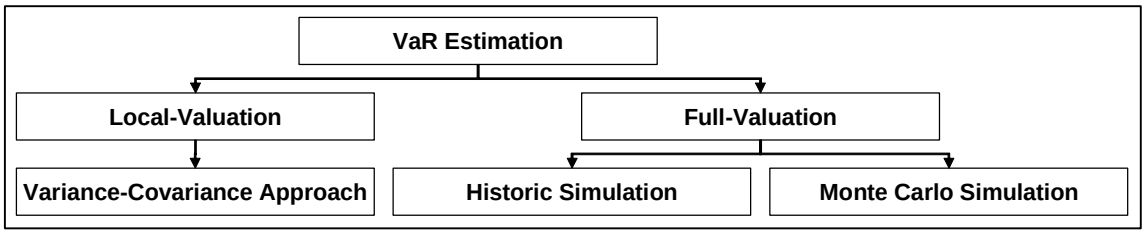

Figure 6: Diagram of common methods to estimate the VaR[201]

In general, three methods to estimate the VaR are practical: The variance-covariance approach, historic simulation, and Monte Carlo simulation.[202]

a) Variance-Covariance Approach

The variance-covariance approach to calculate the VaR is also called delta-normal valuation. Its basic assumption is the normal distribution of results.[203] Firstly, the main risk factors that influence the analysed portfolio have to be identified.[204] In the context of this paper, this identification is part of section 3.1. Secondly, changes to the market price must be linked to variations of the single risk factor (Mapping).[205] Afterwards it is possible to aggregate these positions via a correlation matrix to one VaR amount.[206] For the developed fictive portfolio (see 3.3.1 and appendix B), such an estimation is made in the next section 3.3.2.3 and the corresponding appendix C.

b) Historic Simulation

Using past data in a direct way to anticipate future developments is a popular way to estimate the VaR.[207] In the first step, the historic daily courses of the analysed portfolio and its fundamentally influencing market variables are determined.[208] In the case of this study, the identified price factors (see 3.1.3) that influence the average daily Phelix® of the observed 2,088 trading days (see 3.2.3) could be those variables. Secondly, the percentage changes of each market variable between day i and day $i-1$ for $1 \leq i \leq 2{,}088$ are calculated. Finally, changes to the single risk factors of each day are connected to the portfolio's value and its daily variations. In this case, 2,088 scenarios, one for each analysed trading day, occur. After sorting the scenarios regarding the change of the portfolio's value, the $1-\alpha$ worst value shows the VaR.[209] For example,

[201] Source: Jorion (2007), p. 247f; Prokop (2008), p. 469.
[202] Cf. Prokop (2008), p. 469; Scherpereel (2006), p. 45.
[203] Cf. Prokop (2008), p. 471.
[204] Cf. Scherpereel (2006), p. 45.
[205] Cf. Wenninger (2004), p. 76.
[206] Cf. Romeike/Hager (2009), p. 151.
[207] Cf. Hull (2009), p. 454.
[208] Cf. Prokop (2008), p. 470.
[209] Cf. Hull (2009), p. 454f.

assuming $\alpha = 0{,}01$ the 21st worth scenario (2,088 * 1%) of the determined changes of the portfolio's value is the VaR.

Due to the fact, that the example in this thesis is fictive and no historical portfolio values exist, it is not possible to map the observed changes in the market variables to the total portfolio value. To do this, suggestions regarding historical portfolio values would be mandatory, but this would also lead to arbitrary assumptions and interpretations. Knowing these facts, an estimation of a VaR on basis of the historic simulation is not useful in the context of this paper.

c) Monte Carlo Simulation

Using the Monte Carlo simulation is a challenge because of its complexity. However, this complexity is also reason for the flexibility of this approach and therefore for the accuracy of its results.[210] The Monte Carlo simulation renounces the assumption of normal distribution, but obviously only a limited number of price influencing factors can be considered. Hence, assumptions and restrictions are necessary for the practical use of this approach and this could in turn reduce the accuracy.[211]

In short, the method consists of two steps. Creating a parametric process with the identified risk factors is the first part. Then, price developments for all the risk factors are simulated. Each of these possible price paths is used to compile the distribution of the portfolio's returns and finally estimating a VaR figure.[212]

Using the assumption of normal distribution leads to a similar result as the variance-covariance approach because then it replicates that approach only by using a much more difficult technique.[213] For the reason that such a basic assumption is also mandatory in the context of this thesis to handle the data of the German electricity market, there is no empirical analysis made based on the Monte Carlo Simulation. Rather, on basis of above-mentioned argumentation it is possible to refer to the empirical results of the variance-covariance approach (see next section 3.3.2.3).

3.3.2.3 VaR Estimation of a Power-Trading Utility's Portfolio

To illustrate a risk management strategy of a utility, the focus of this thesis is on the optimisation of daily procurement and sale of electricity to maximize the total portfolio return.[214] Therefore, the consideration of inter-daily fluctuations and corresponding hourly VAR calculations are beyond the scope of this study (see 1.1). The target is to

[210] Cf. Chen/Glasserman (2008), p. 508; Jorion (2007), p. 307; Prokop (2008), p. 473.
[211] Cf. Romeike (2009), p. 11.
[212] Cf. Jorion (2007), p. 265f.
[213] Cf. Prokop (2008), p. 475.
[214] Cf. Zhou, et al. (2006), p. 187.

concentrate on daily optimisation to analyse some general possibilities of risk management, because this also provides insights into a few inter-daily risk management approaches basing on derivatives with different maturities (see 4.2.2). Hence, the objective is to estimate the VaR on the basis of the average daily Phelix® baseload monthly index.

According to the previous section, the VaR estimation of the fictive utility's portfolio is based on the variance-covariance approach. For the first step, risk identification, it is possible to refer to 3.1. Remember, the market price risk is the central risk for a utility in the described environment. This risk consists especial of the superior price and volume risk. Hence, the variance-covariance approach considers the volume risk in form of a decreasing power demand as first aggregated risk factor. The other risk factor is the fluctuating spot price on the EPEX Spot representing the price risk due to the necessary adjustment of the supply with spot market volumes (see Figure 5, p. 25).

In appendix C, the VaR of the utility's portfolio (see 3.3.1) is estimated on daily basis with a confidence level at 99% ($\alpha = 0{,}01$). The expected rate of return (μ_{PF}) and the standard variance (σ_{PF}) of the portfolio is calculated with equations that can be ascribed to the Markowitz portfolio theory (1952).[215]

$$\mu_{PF} = \sum_{i=1}^{N} x_i \mu_i \tag{IX}$$

$$\sigma_{PF} = \sqrt{\sum_{i=1}^{N} x_i^2 \sigma_i^2 + \sum_{i=1}^{N} \sum_{\substack{j=1 \\ j \neq i}}^{N} x_i x_j \sigma_{ij}} \tag{X}$$

with N : Numbers of risk factors within the portfolio

x_i : Share of risk factor i at the total invested capital

μ_i : Expected rate of return of risk factor i

σ_i : Standard variance of risk factor i

σ_{ij} : Covariance of the returns of the risk factors i and j [216]

These formulas lead to following results (see appendix C):[217]

$$\mu_{PF} = x_S \mu_S + x_P \mu_P = \frac{10{,}000{,}000}{10{,}000{,}000} * 0.1401 + \frac{2{,}000{,}000}{10{,}000{,}000} * 0.1134 = 0.1628 \tag{XI}$$

$$\sigma_{PF} = \sqrt{x_S^2 \sigma_S^2 + x_P^2 \sigma_P^2 + 2 x_s x_P \sigma_{S,P}} \tag{XII}$$

[215] Cf. Prokop (2008), p. 471; fundamental paper: Markowitz (1952), p. 77-91.
[216] Cf. Prokop (2008), p. 471.
[217] Own calculation (2010), *local link*: "Wittenberg; Appendix C – VaR.xls", table: VaR

$$= \sqrt{1^2 * 0.1175^2 + 0.2^2 * 0.1205^2 + 2 * 1 * 0.2 * 0.006} = 0.1296$$

Finally, the daily VaR can be estimated by considering -2.3263, which is the value of the basically assumed normal distribution (see 3.3.2.2), the chosen probability of occurrence of 1% ($\alpha = 0{,}01$), μ_{PFi}, σ_{PF}, and the current value of the portfolio (V_{PF}).[218]

$$VaR_{Daily} = -V_{PF} * (\mu_{PF} - 2.3263 * \sigma_{PF}) \qquad \text{(XIII)}$$

$$= -245{,}731\ TEUR\ * (0.1628 - 2.3263 * 0{,}1296) = 34{,}098\ TEUR$$ [219]

As a result, with a probability of 99% the portfolio's value will not decrease by more than TEUR 34,098 within one day. This corresponds to maximal daily loss of approximately 14% (34,098 / 245,731 * 100).

3.3.2.4 Benefits and Limits of the VaR

The introduction mentioned the advantage of the VaR, its meeting of management requirements with one single and easy interpretable key figure, which measures an accumulation of risks.[220] Furthermore, the VaR is interesting for companies making up the balance according to the International Financial Reporting Standards (IFRS). Beside internal risk management requirements such as economic reasons,[221] the VaR satisfies external demands because it is a legally established risk management tool.[222] Therefore, the VaR is used simultaneously as an internal controlling instrument to satisfy the requests of the upper and top management and to provide first rudimental information about the company's risk situation to external shareholders, potential investors, and balance analysts.[223]

However, especially because the VaR is understandable even by non-specialists the hazard of overreliance of its results and misinterpretations arises.[224] Problems occur because of the immense consolidation of different factors to one single amount. Information that might be crucial for the correct interpretation of the VaR could get lost.[225] Weaknesses of this concept are already caused by inherent properties of the risk management. All methods start with the risk identification. This contains the imminent danger of disregarding risk elements maybe due to a lack of knowledge or

[218] Cf. Prokop (2008), p. 472.
[219] Own calculation (2010), *local link*: "Wittenberg; Appendix C – VaR.xls", table: VaR
[220] Cf. Basak/Shapiro (2001), p. 371.
[221] Cf. Fleischer (2009), p. 11f.
[222] Cf. IFRS 7.40f.
[223] Cf. Prokop (2008), p. 476.
[224] Cf. Krause (2003), p 19.
[225] Cf. Linsmeier/Pearson (2000), p. 62.

wrong subjective estimations. There are some solutions to mitigate this problem such as teamwork[226] but their analysis is beyond the scope of this study.

The VaR strongly depends on assumptions. The determination of confidence level, the sample period, and the holding period of the open positions are based on subjective estimations.[227] Moreover, each method to estimate the VaR is based on historic data, which, of course, provides the most reliable data but relies on the suspect idea that the future is comparable to the past.[228] Even if these are all necessary assumptions and techniques, it always opens a field of general critique on the VaR.

Moreover, the VaR can introduce some wrong incentives because it is not subadditive, which means the sum of losses of the individual risks within the portfolio can be different to the aggregated loss of the VaR. Hence, this constraint can disturb the company's optimal investment strategy due to wrong interpretations by the management. Furthermore, the concept only provides a statement of the probability of losses but not of their value. This contains the danger of underestimating risks which occurrence is not very likely but perhaps threatens the existence of the entire enterprise.[229] An alternative concept that deals with the problems of missing subadditive and the value of potential losses is expected shortfall, the so-called conditional VaR (C-VaR). Nevertheless, the VaR and not the C-VaR is still the most popular concept in economic practice.[230] Therefore, this thesis does not analyse the C-VaR in detail and refers to the professional literature on this topic.[231]

In summary, in spite of several weak points the simplicity of the VaR and maybe the lack of feasible alternatives for purposes of economic practice lead to the wide spread of this concept in financial and non-financial markets, especially in energy markets.[232] Even if this thesis cannot deny this fact and concentrates on the VaR, an alternative concept, especially with respect to the specifics of the German electricity market is analysed in the following part 3.3.3.

3.3.3 Single-Factorial Sensitivity Analysis

Referring to the argumentation in 3.2 that complex models do not mandatory provide more accurate power forecasts, it also seems to be adequate to analyse a simple method for measuring the price risk of a utility. Therefore, a single-factorial sensitivity

[226] Cf. Strohmeier (2007), p. 38f.
[227] Cf. Prokop (2008), p. 476.
[228] Cf. Linsmeier/Pearson (2000), p. 62.
[229] Cf. Boyle/Hardy/Vorst (2005), p. 48-50.
[230] Cf. Hull (2009), p. 453; Prokop (2008), p. 477.
[231] Cf. Artzner, et al. (1999), p. 203-228; Hull (2009), p. 453; and others.
[232] Cf. Al Janabi (2009), p. 19-22.

analysis with only one risk factor could be an alternative to the VaR concept. Besides the multi-factorial VaR concept, the single-factorial sensitivity analysis is accepted within the IFRS[233] to analyse "(…) how profit or loss and equity would have been affected by changes in the relevant risk variable (…)".[234]

The objective of a sensitivity analysis is the evaluation of how sensitively the value of a financial instrument or portfolio reacts to variations of one, in case of a single-factorial sensitivity analysis, or more price determining risk factors.[235] After identification of the risk factors, the volatility of these variables in form of standard variances is determined. In the third step, it is possible to asses the reaction of the derivative or entire portfolio for different scenarios regarding the development of the identified risk factor respectively factors to estimate the sensitivity.[236]

Based on the argumentation of part 3.1.1, the volume risk in its fundamentals is very similar to the price risk, because missing or redundant volumes have to be bought or sold at current spot market prices.[237] Therefore, regarding the objective to estimate daily volatility of the portfolio's value, the daily average Phelix® can be used as the one risk factor that builds the basis of the single-factorial sensitivity analysis.

The sensitivity analysis in appendix D provides a set of results. For a sample period of 2,088 trading days from 01/01/2002 to 12/31/2009, the variance of the daily Phelix® is $\sigma_{day}^2 = 261.09$ EUR/MWh and the daily volatility is $\sigma_{day} = \sqrt{261.09} = 16.16$ EUR/MWh or 12.2 % (see Figure 24, p. 88). However, as illustrated in appendix D (see Figure 25, p. 88) the volatility strongly depends on the sample period. Hence, for a sample period of five years (2005-2009) it is σ_{day} = 15.71 EUR/MWh (10.8 %), for three years (2007-2009) it is σ_{day} = 17.25 EUR/MWh (12.1 %), and for the year 2009 it is σ_{day} = 7.51 EUR/MWh (6.5 %). The period chosen by the management depends on the analysed product.[238] Even if the determined period is often one year,[239] in case of the Phelix® it is obvious, that the 2009 volatility strongly differs from previous years. Hence, the results should be interpreted very careful and the current development of the electricity price has to be observed with extraordinary diligence. Currently, the standard variance of the month January to May 2010 is σ_{day} = 3.34 EUR/MWh (7.9 %) (see appendix D, Figure 26, p. 89).

[233] Cf. IFRS 7.40f; Prokop (2008), p. 466.
[234] IFRS 7.40 (a).
[235] Cf. Cortez/Schön (2009), p. 418.
[236] Cf. Hungenberg (2008), p. 305.
[237] Cf. Kremp/Rosen (2002), p. 48f.
[238] Cf. Hull (2009), p. 376.
[239] Cf. Prokop (2008), p. 467.

Again, beginning with the portfolio value of EUR 245,731 determined in appendix B, it is possible to calculate a potential loss of one trading day by simple multiplication. According to the chosen sample period, the risk sensitivity of the portfolio also varies enormously. Hence, the potential loss within one trading day of the portfolio varies from TEUR 16,080 to TEUR 30,038.

Sample period	Standard variance	Change in portfolio value [TEUR]	Estimated portfolio value [TEUR]
2002-2009	12.2%	-30,038	215,693
2005-2009	10.8%	-26,503	219,228
2007-2009	12.1%	-29,801	215,930
2009	6.5%	-16,080	229,651

Figure 7: Sensitivity Analysis – Risk sensitivity of the portfolio[240]

In summary, with reference to the average daily Phelix® Baseload monthly index (see Figure 4, p. 22) it seems to be a trend of decreasing volatility. Nevertheless, after the years from 2002 to 2008 of high volatility, this trend has to be examined very careful. It should not lead to an underestimating of the risks due to the dynamic and volatility of the power price. On the German electricity market, the period of lower standard variance is quite short. The market is still sensitive to external shocks (see 3.1.3).[241] Therefore, spike prices with a daily average Phelix® of maximal 45.88 EUR/MWh and minimal 21.05 EUR/MWh in 2010 still occur (see appendix A, Figure 13, p. 80).

3.4 Résumé

The criticism at the analysed concepts VaR and sensitivity analysis sensitized for a wide area of problems beginning with the setting of assumption up to misinterpretations of the results (see 3.3). It seems that the disadvantages outweigh the advantages and leads to the question of the efficiency of such risk management instruments. However, not direct quantifiable risks are economically significant. Hence, if a risk measurement on an organised market is not possible it is mandatory to evaluate the risk on basis of its factors of influence.[242] To implement a (risk management) strategy successfully it is fundamental to translate the strategic high-level objectives into specific tasks. Only then is it possible to evaluate one's own work and achieve progresses.[243]

The requirement to operationalize strategic objectives is fulfilled by the above-mentioned concepts, even if the work with these instruments requires due diligence. The wide range of potential results explicitly demonstrates this. Results vary from a

[240] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix D - Singe-Factorial Sensitivity Analysis", table: Portfolio_Sensitivity.
[241] Cf. Al Janabi (2009), p. 16f.
[242] Cf. Wolke (2008), p. 63f.
[243] Cf. Kaplan/Norton (2004), p. 28.

daily risk of losing from 6.5 % up to 12.2 % of the portfolios value by evaluating it on basis of a single-factorial sensitivity analysis. The result of the VaR estimation shows that with a probability of 1 % even a loss of more than 14 % is possible, though without mentioning an explicit value.

Results of VaR and sensitivity analysis are not comparable due to their different objectives. Both concepts just display some aspects of the market risk depending on assumptions and empirical data. Nevertheless, both are a practical compromise and legally approved.[244] They also provide a starting point for an efficient risk management strategy. The absolute key figures do not deliver the needed information regarding the measurement of the portfolio risk but their benchmark. Improvements of the risk management system and effectiveness of risk management instruments as well as eventually necessary actions become obvious. Furthermore, key figures can be used as early warning indicators in case of critical developments.[245]

Using VaR and sensitivity analysis successfully requires a continuous process. The principle of consistency in the assumptions, calculations, and interpretations of the results is the basic requirement for any benchmark or evaluation of different tasks as well as to fulfil IFRS regulations.[246] However, it is important to avoid organisational blindness. That means, not only one's own work and the measurement concepts but also the environment have to be constantly analysed. If necessary, assumptions need to be adjusted.[247] An example for such a requirement could be the determined trend of a decreasing volatility of the spot market prices in 2009 and 2010. If measuring the risk it might be useful to change the assumptions regarding the sample period.

In summary, it is quite impossible to master all the challenges of the dynamic environment of electricity markets with one risk measurement concept. Therefore, to make shareholders, senior managers, and other stakeholders feel more comfortable with the level of risk, enterprises should combine different concepts and maybe implement stress-testing systems.[248]

Finally, the potentially high losses of more than 6.5 % per day show the necessity to hedge these risks. Hence, after description, characterization, and assessment of some concepts to measure the risk of a utility in the German electricity market within this chapter, concrete instruments and strategies are analysed in the remaining parts of this thesis. Thus, a general overview of potential risk management strategies for a utility in such an environment should be provided.

[244] Cf. Prokop (2008), p. 478f.
[245] Cf. Schneiter/Cajos (2009), p. 534-536.
[246] Cf. Pellens, et al. (2008), p. 117.
[247] Cf. von Benölken/Müller (2010), p. 1332.
[248] Cf. Al Janabi (2009), p. 27.

4 Risk Management of Power-Trading Utility Companies

4.1 Purpose and Objectives of Risk Management

As clarified in chapter 3, there is an increasing importance of managing price risks in the German electricity market. Risk management can reduce the volatility of the earnings, maximize the shareholders value, and it promotes job and financial security. It is in the focus, because the top management is usually directly responsible.[249]

Various reasons for risk management indicated in 2.3 can be summed up in three categories. First, the legal framework provides different regulations, which are of special interest for utilities. Laws such as the KonTraG (see 2.3) require comprehensive due diligence. Second, some exemplary economic reasons for risk management are the before-mentioned deregulations, volatility, or free markets with increasing competition. Third, the technological progress, especially modern information and communication technology (ICT) that is associated with new possibilities as well as shorter reaction times on environmental changes or shorter lifecycles of the products reinforce the increasing relevance of risk management.[250]

It is practical to differentiate in two general types of risk management objectives. Risk management can be used to minimize the fluctuations of the value of the portfolio and hence reduce the uncertainty. Alternatively, to guaranty a minimum profit it could be the aim to fix the maximum loss by immunizing a predefined net position against all risks.[251] Common to both approaches is the purpose to secure the existence, ensure the success, and increase the value of the company.[252]

Risk controlling is a part of risk management. It supports the responsible management of the company with the provision of relevant information as well as in planning and steering risks.[253] Hence, its purpose is monitoring and organising while the term risk management describes the concrete execution of the tasks.[254]

To develop risk management strategies in section 4.3 some basic assumptions must be set. It is assumed, that the utility's management is risk avert. Furthermore, the decisions of the utility company do not have any influence on market prices. Therefore, the company is price-taking market participant.[255]

In the next section 4.2, some instruments to ensure an effective risk management of a power-trading utility in the German electricity market are analysed.

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[249] Cf. Lam (2003), p. 6-9.
[250] Cf. Fleischer (2009), p. 11; Wolke (2008), p. 2f.
[251] Cf. Bakshi/Cao/Chen (1997), p. 2006.
[252] Cf. Fleischer (2009), p. 10.
[253] Cf. Bährle (1997), p. 49.
[254] Cf. Wolke (2008), p. 2.
[255] Cf. Fleten/Wallace/Ziemba (2002), p. 72.

4.2 Risk Management Instruments

4.2.1 Design and Analysis of Purchase and Sales Agreements

As mentioned in 3.3.1, the portfolio of a power-trading utility includes several contracts for power supply and demand.[256] Imprecisely and not clearly formulated contracts are significant reasons for diverse kind of risks. Moreover, completely, transparent, and explicit modelled contracts that consider technical, economical, and legal aspects improve the cooperation of the utility with its partners.[257]

a) Purchase Agreements

According to Figure 5 (p. 25), reliably forecasted consumption can be covered by long-term agreements with ESCs. Vertical commitments with an ESC to deliver electricity at a fixed price are typical bilateral contracts to obtain such highly probable needed power volumes.[258] As suggested in 3.3.1, it is realistic that an ESC offers diverse contractual arrangements for different blocks of hours throughout a day such as baseload, peakload, and off-peakload as well as for the seasons of the year. Typically, it defines a minimum, a so-called take-or-pay clause, which is unobjectionable,[259] and probably a maximum of power that will be delivered at the contracted conditions.[260]

Due to the liberalisation of the German electricity market, the market position of the utilities has improved. Whereas in former times an ESC asserted contract clauses that tied the utility to an exclusive supply of power, today such exclusivity clauses are void and prohibited.[261] Furthermore, long-term purchase agreements between an ESC and its customers without sufficient possibilities to annul the contract violate German laws.[262] Hence, an effective way to reduce the inherent volume and price risk of purchase agreements with ESCs is a flexible contract design. The utility could enter into an interruptible contract, which allows to renege its obligation to take the electricity volumes a certain number of times over the contracting period. In return, it maybe pays agreeable higher power supply prices or extra fees.[263]

In July 2010, the BKartA further strengthened the right of clients of ESCs. To abandon anti-competitive contract clauses, the BKartA needs the energy suppliers to renounce resale bans. Those clauses prohibited utility companies or other customers of the

[256] Cf. Fleten/Wallace/Ziemba (2002), p. 71.
[257] Cf. Harrant/Hemmrich (2004), p. 31.
[258] Cf. Bushnell/Mansur/Saravia (2008), p. 238.
[259] Cf. Bundekartellamt (BKartA) (2010), p. 1.
[260] Cf. Conejo/Fernández-González/Alguacil (2005), p. 358f.
[261] Cf. Grichnik/Vortmeyer (2002), p. 384.
[262] Cf. Lukes (1999), p. 20.
[263] Cf. Ross/Kolos/Tompaidis (2006), p. 627.

ESCs from reselling their minimum take. Following this judgement, twelve of the major German suppliers pledged to abandon those clauses.[264]

b) Sales Agreements

In the course of liberalization, the rights of the end-customers increased as well. Several German laws such as the ordinance regulating the provision of basic electricity supplies (StromGVV) regulate contract condition between utilities and households.[265] The EnWG added further regulations, for instance regarding the supply of end-customers and the corresponding conditions or tariffs.[266]

To distress some conditions of such basic mandatory provision agreements with basic supply, power traders offer special electricity contracts. The price conditions are not oriented on legal regulations but on market conditions, which is also valid. Regularly, price conditions in such special agreements are more favourable for end-customers. In return, utilities can push through longer periods. Contracting periods of one to two years are typical. Due to lower prices, special contracts have become more appealing to the customers.[267] Orientating on spot prices and longer contracting periods means lower price risks for a utility. Price fluctuations are at least partly forwarded to the end-customer and longer periods increase the planning security. Hence, lower trade prices are some kind of acceptable risk management expenditures for a utility.

Considering the dynamic (legal) environment characterised in a) and b), utilities need to expand their focus on designing purchase and sales agreements. To reduce contractual risk managerial flexibility and up-to-date decisions instead of subjective haphazard trading decisions are essential to optimize profits and minimize risks.[268]

Due to the strategic importance and the low possibility of substitution, electricity is in the political focus of most governments.[269] This confirms the close legal framework in Germany with different laws such as the EnWG, EEG, or the StromGVV. Therefore, a proper legal contract design is mandatory to avoid risks[270] such as reimbursements, legal charges, or losses in reliability and finally a decrease in clients and profits.

To close the gap between power supply and demand (see Figure 5, p. 25) utilities should use the above-mentioned flexible contract design possibilities. Especially synchronizing contract periods and refereeing in purchasing and sales agreements to comparable basis prices such as the Phelix® causes a natural hedge.

[264] Cf. Bundekartellamt (BKartA) (2010), p. 1.
[265] Cf. §1 StromGVV.
[266] Cf. §§ 36-42 EnWG.
[267] Cf. Zornow (200), p. 19.
[268] Cf. Wang/Min (2008), p. 365.
[269] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 113.
[270] Cf. Harrant/Hemmrich (2004), p. 31.

However, even if a utility company designs its agreements regarding some of these recommendations, the typical utility may not hedge the complete peak demand and its margin is still exposed to the spot prices on the EEX.[271] For further minimisation of the price risks, various financial instruments established. Therefore, financial contracts, the third part of the utility's electricity portfolio,[272] are analysed in the following parts.

4.2.2 Derivatives to Hedge Market Price Risks

4.2.2.1 History and Terminology

Forward contracts are no innovation of the modern age. In fact, Aristotle already mentioned options. By the 17th century, there was an organised trade of tulip options in Amsterdam and of the future delivery of rice in Osaka.[273] However, the initial point of the dynamic development of derivatives in modern financial markets is the collapse of the fixed exchange rates system of Bretton Woods in 1973. The market price risks had grown enormously due to the arising exchange rates fluctuations and interest rates variability. The request to hedge such risks caused the invention of derivatives that developed to a main financial instrument to manage theses risks.[274]

In the economic research, Merton and Scholes, in collaboration with Black, created a fundamental model to determine the value of derivatives. Black and Scholes published this pioneering theory in 1973 and the Nobel Price Committee awarded it in 1997.[275] Following models relaxed some of the restrictive assumptions of this theory but all of them were generally based on the work of Merton, Scholes and Black.[276]

In the economic practice, first organised markets for forward contracts established also in the 1970s. The first trade with currency futures at the Chicago Mercantile Exchange (CMD) started in 1972. The beginning of organised forward trading in Europe was in 1978 at the European Options Exchange (EOE) in Amsterdam followed by the London International Financial Futures Exchange (LIFFE) in 1982.[277] One of the most essential changes for financial markets was the diffusion of electronic financial services since the early 1980s by using innovative ICT.[278] On basis of modern ICT, derivate financial markets are growing rapidly worldwide since the end of the 1980s. Especially in the 1990s, the use of financial products expanded dramatically.[279]

[271] Cf. Ross/Kolos/Tompaidis (2006), p. 628.
[272] Cf. Fleten/Wallace/Ziemba (2002), p. 71.
[273] Cf. Hodgson (2009), p. 1.
[274] Cf. Pryke/Allan (2000), p. 280.
[275] Cf. Jarrow (1999), p. 229; fundamental paper: Black/Scholes (1973), p. 637-654.
[276] Cf. Bakshi/Cao/Chen (1997), p. 2003.
[277] Cf. Noll (2000), p. 246.
[278] Cf. Montazemi/Irani (2009), p. 122f.
[279] Cf. Lien/Zhang (2008), p. 40 & 44.

Today forward contracts are synthetic financial products, which always derive there value from an underlying asset. This could be an index, currency, bond, interest rate, or a commodity like oil, gas, or electricity. Common to all kinds of derivates is the dependence of their value on the development of the corresponding underlying.[280] Generally, derivatives are interrelations between two contracting parties. At conclusion of this bilateral contract, there is an agreement upon all rights and obligations for the future performance date or time.[281] Derivatives could be either standardized or individual contracts. Structured financial products based on standardized arrangements are traded on various exchange-markets such as the above-mentioned CMD, EOE, or LIFFE, while individual financial agreements are fixed bilateral OTC.[282]

Important termini are the short position, the sale of a forward contract, and its opposite the long position that describes the buying of a derivative. Thus, if a trader goes short he anticipates decreasing market prices of the underlying asset. The long position expresses rather the expectation of a rising rate. A put means a selling of a long or a short position. A call describes its buying at the agreed price (strike price or exercise price).[283] Because of the anticipation of future developments, derivatives always contain opportunities and risks. Therefore, they could be used for different purposes of the traders. Initially, the intention of an investor to reduce respectively totally remove risks on volatile markets was the central motive to trade with derivatives. In addition, derivate instruments could be used to gain profits.[284] However, the classification of the trader's intentions in hedging, arbitrage, and speculation is part of the analysis of possible risk management strategies in section 4.3.[285]

There are two general types of derivates existing. Unconditional forward contracts are commitments of all involved parties to fulfil the conditions of the contract. On the other hand, there are conditional contracts. In this case, one party has the right to insist in or to relinquish the fulfilment of the contract while the other party has the duty to ensure its compliance.[286] The execution of the contract could be either by physical delivery (physical settlement) or by paying the profit respectively loss to the counterparty (cash settlement).[287] The next part 4.2.2.2 characterises the general unconditional forward contracts forwards, futures, and swaps and the conditional options.

[280] Cf. Mittra (1995), p. 58.
[281] Cf. Noll (2000), p. 247.
[282] Cf. Muck (2006), p. 82.
[283] Cf. Wolke (2008), p. 89.
[284] Cf. Kim (2008), p. 707f.
[285] Cf. Ghosh/Arize (2003), p. 473f.
[286] Cf. Schwarz (2006), p. 17.
[287] Cf. Chan/Lien (2001), p. 65f.

4.2.2.2 Typology

a) Unconditional Forward Contracts

Unconditional forward contracts are relatively simple agreements to buy or sell an asset in the future at the exercise price. Forward contracts are traded OTC.[288] Comparable to forwards are futures. In contrast, these derivatives are standardized products that are traded on organised exchanges.[289] Forwards and futures provide the possibility of short or long trading with two kinds of payoff profiles.

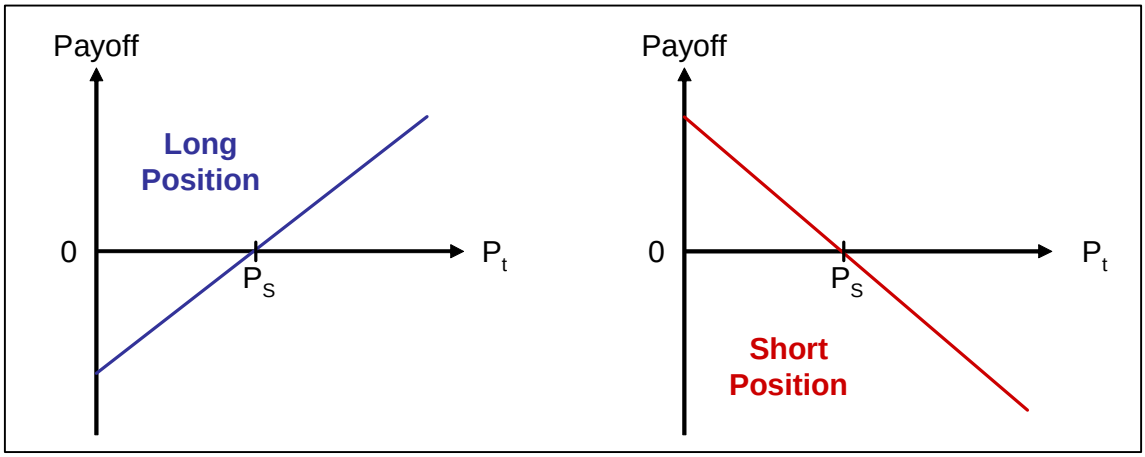

Figure 8: Payoff profiles of forward and future contracts[290]

The payoff of the long position is the difference of the price of the underlying at contract maturity P_t and the agreed strike price P_S and positive in case of an increasing price.

$$Payoff_{Long} = P_t - P_S \tag{XIV}$$

The short position provides a converse payoff profile with gains in case of a decreased price at maturity.[291]

$$Payoff_{Short} = P_S - P_t \tag{XV}$$

Forwards are very important for the management of exchange rate risks, interest rate risks, and commodity risks[292] such as the market price risk for electricity. A typical contract that can be either OTC or exchange traded allows one counterpart to receive a fixed volume of MWh for a specific price at the contracted location and time.[293]

A mean characteristic is the concept of clearing mentioned in 3.1. The clearing house is a counterpart of the trading participants. It regulates and collateralizes generally the

[288] Cf. Hull (2009), p. 3f.
[289] Cf. Rudolph/Schäfer (2010), p. 25.
[290] Source: Hull (2009), p. 5.
[291] Cf. Cusatis/Thomas (2005), p. 98; Hull (2009), p. 5.
[292] Cf. Korn (2010), p. 102.
[293] Cf. Hull (2009), p. 585.

exchange-based trading.[294] Such a firm guarantees the performance of the permitted parties on an organised exchange.[295] In the context of this thesis, clearing refers to the period after the parties entered the legal obligation at the trading and before the fulfilment of this obligation at the settlement (cash or physical). Within this phase, clearing describes the monitoring, management, and finally preparation of settlement of the open trading positions. This comprises several basic clearing services of the clearing house, including the trade confirmation that minimizes the credit risk (see 3.1.1).[296] For providing and financing these services, clearing houses require fees in form of margins. Depending on the size of the open trading position and the volatility of its underlying, also the EEC charge margins, which the traders either in cash or in securities can pay. Furthermore, all clearing members and the EEC provide additional capital in a mutual clearing fund in case of default. If traders are registered at the EEX or an official partner exchange, the EEC provides also clearing services for OTC transactions.[297] Therefore, an instrument against credit risk even on OTC markets established for power trading. Assuming the efficiency of the EEC, the counterparty risk is no field of further interest and research in the context of this study.

Prices of forwards and futures depend on the price of the underlying, cost of carry and other variables. Central aspect of each forward contract is the fact of a temporary difference between signing and executing the contract. Hence, besides the spot price of the underlying, second forward respectively future prices arise. Spot and future prices are connected in some way because the forward contract is derived from its underlying (see 4.2.2.1).[298] At the end of the forward contract period, spot and future price converge to the same level due to the fact of the decreasing uncertainty regarding future developments.[299] In case of the EEX, possible underlyings of the traded Phelix® futures are the Phelix® baseload (see Figure 4, p. 22), peakload, or off-peak monthly index.[300]

A common concept to explain differences between spot and future prices within the contracting period is the cost of carry approach. In general, storage cost plus interest to finance the asset less income earned on this asset explain the difference.[301] Hence, cost of carry answers the question, what would it cost to buy the asset today and storage until the day of its usage. However, especially this basic assumption of storing

[294] Cf. Rudolph/Schäfer (2010), p. 67.
[295] Cf. Hull (2009), p. 776.
[296] Cf. Hasenpusch (2009), p. 18-20.
[297] Cf. ECC (2010), p. 7-10.
[298] Cf. Hull (2009), p. 99.
[299] Cf. Hull (2009), p. 25f.
[300] Cf. EEX (2010a), p. 14.
[301] Cf. Hull (2009), p. 118.

the underlying is not complied in case of the non-storable commodity electricity. Alternative methods of valuing can be differentiated in three categories.[302] First possibility is the pricing by use of non-arbitrage relationships of electricity to exchange-traded primary energy carriers, but this requires intensive background knowledge. Second, economic approaches use stochastic processes bases on historical data to explain spot price developments (see 3.2). Third, microeconomic models consider cost and utility functions of market participants to determine an equilibrium price.[303] With reference to chapter 3, detailed repetitions of the pricing processes are not necessary.

Beside futures and forwards, swaps are the third general form of unconditional forward contracts. In its basics, a swap is a fixed-for-floating swap. One party changes its variable payments for example basing on the Phelix® spot price against fix cash flows of the counterpart. Each trading partner is committed to pay the difference between fixed and variable payment. Hence, swaps are usually executed as cash settlements with the intention to hedge price risks on basis of different expectations, conditions, or requirements of the swap counterparts.[304] Besides this most common kind of swap switching fixed to floating cash flows called plain vanilla swaps, further swap variations are possible that are generally created by financial engineers for OTC transactions.[305] An optimal risk management strategy is therefore also depending on creativity, negotiation skills, and further abilities of the risk manager.[306]

b) Conditional Forward Contract

Conditional forward contracts are options traded OTC or at organised markets. The buyer of an option (holder) acquires from the seller (writer) the right but not the obligation to buy the underlying asset at the agreed time for the exercise price. In return for this unilateral right, the holder has to pay a premium to the writer. If the settled expiration date of the option is only at one determined date, it is a European option. It is an American option, if the execution is possible during the contracting period until maturity.[307] The right of the holder to buy the underlying but without the duty to exercise this right is the main characteristic that distinguishes options form forwards and futures. Whereas, disregarding transaction costs, it costs nothing to enter in an unconditional forward contract; there are costs to purchase an option.[308]

Four kinds to use options with different intentions and payoff profiles are possible:

[302] Cf. Wilmschulte/Wilkens (2004), p. 123f.
[303] Cf. Pschick (2008), p. 153; Wilmschulte/Wilkens (2004), p. 124.
[304] Cf. Abumustafa (2006), p. 28f.
[305] Cf. Hull (2009), p. 2009.
[306] Cf. Kim (2007), p. 32.
[307] Cf. Hartmann-Wendels/Pfingsten/Weber (2010), p. 272.
[308] Cf. Hull (2009), p. 7.

- Long call: The holder buys the option, pays a premium, and gets the right to buy the underlying at the strike price (P_S) and expiration date.
- Short call: The writer sells the option, gets a premium, and takes the obligation to sell the underlying at the strike price (P_S) and expiration date.
- Long put: The holder buys the option, pays a premium, and gets the right to sell the underlying at the strike price (P_S) and expiration date.
- Short put: The writer sells the option, gets a premium, and takes the obligation to buy the underlying at the strike price (P_S) and expiration date.[309]

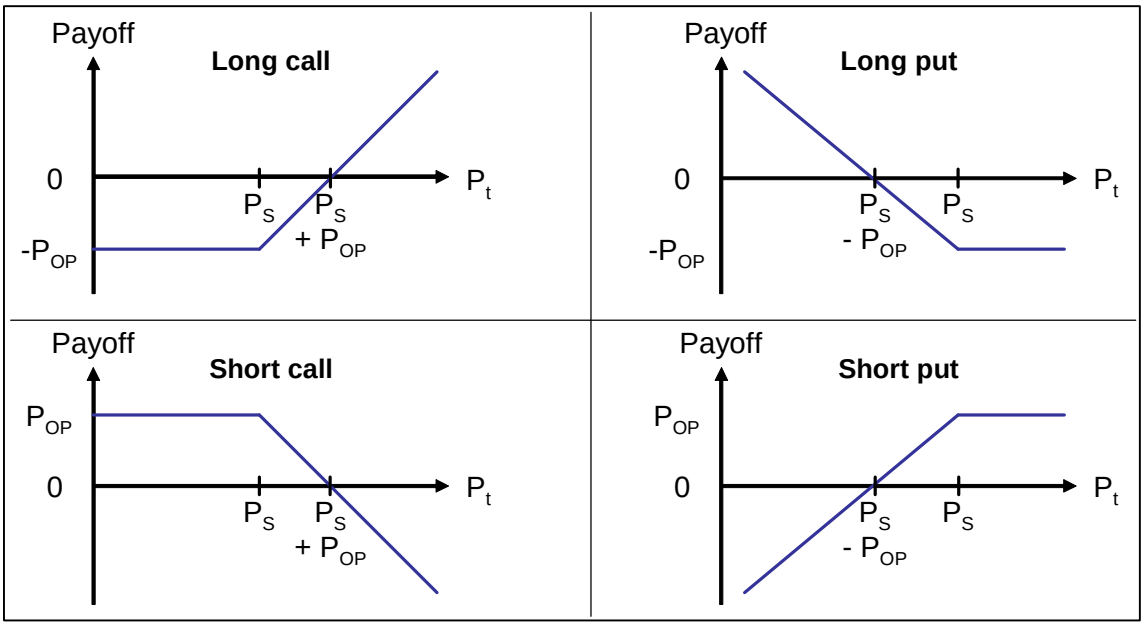

Figure 9: Payoff profiles of different types and positions of European options[310]

The writer always gets the premium in the amount of the option's price P_{OP}. This is consequently the maximum profit per option of a short position. In contrast, P_{OP} is the maximum loss of a long position per option. As illustrated in Figure 9, different intentions regarding risk disposition and price expectation are the basis for the decision on how to use the option. Hence, following assumptions are fundamental:

- Long call: Strongly increasing price of the underlying (P_t)
- Short call: Stagnating or decreasing price of the underlying (P_t)
- Long put: Strongly decreasing price of the underlying (P_t)
- Short put: Stagnating or increasing price of the underlying (P_t)[311]

The concept of clearing is comparable to forwards and futures. Here, too, the ECC offers clearing services for exchange and OTC transactions.[312]

[309] Cf. Ashauer/Bonenberger (2007), p. 112
[310] Cf. Hull (2009), p. 180-183.
[311] Cf. Heinzel/Knobloch/Lorenz (2002), p. 151.
[312] Cf. ECC (2010), p. 3.

4.2.2.3 Energy Derivatives in the German Electricity Market

After the general characterization of derivatives, energy derivatives traded on the EEX, which are of special interest in the scope of this thesis, are analysed in the following. According to the objective, to hedge the daily risks measured in 3.3, derivatives traded on the EEX and OTC with contracting periods up to several years[313] are considered. Derivatives traded on the EEX do generally not comprise physical settlement during the contracting period. They are primary used as instrument to hedge market price uncertainties.[314]

a) Phelix® Futures

The underlying of these futures is the day-ahead price of daily auctions.[315] For all subsequent characterised Phelix® futures three profiles regarding their daily time of execution are available. To hedge the delivery of power (purchase or sale) in the time from 9 am to 9 pm peakload futures, from 9 pm to 9 am off-peak futures, and for the total 24 hours of the day baseload futures are offered.[316] Depending on the profile, the underlying index is the arithmetic average baseload, peakload, and off-peak price for electricity at the day-ahead auctions of the specific period on the EPEX Spot.[317]

Various types of Phelix® futures differ regarding their contracting period. Year futures enable hedging of electricity prices from one to six years. Quarter futures comprise up to eleven quarters. Three trading days before delivery, year and quarter futures cascade into to the shorter quarter respectively month future. Month futures are traded for the current and the next nine months.[318] To cover the period of a month, week futures for the current and, at maximum, next four weeks are available.[319]

Each future contract contains a constant delivery rate of one megawatt per hour within the delivery period. Hence, baseload futures contain 24 hours, peakload, and off-peek futures accordingly less than that. Therefore, a baseload year future has the contract volume of 8,760 MWh (365 days * 24 h * 1 MWh).[320] Exemplary, for the month January, one baseload month future has a volume of 744 MWh (31 days * 24 h * 1 MWh)[321] and one baseload week future contains 168 MWh (7 days * 24 h * 1 MWh).[322]

[313] Cf. Jahn (2008), p. 302.
[314] Cf. Bierbauer, et al. (2007), p. 3469.
[315] Cf. Ockenfels/Grimm/Zoettl (2008), p. 11.
[316] Cf. EEX (2010b), p. 1.
[317] Cf. Bierbauer, et al. (2007), p. 3469.
[318] Cf. EEX (2010a), p. 14.
[319] Cf. EEX (2010c), p. 1.
[320] Cf. EEX (2010a), p. 14.
[321] Cf. Grichnik/Vortmeyer (2002), p. 390.
[322] Cf. EEX (2010c), p. 1.

Because futures with shorter contracting periods of a month respectively a quarter automatically replace quarter respectively year futures, there is no final settlement of these derivatives. Month futures are tradable during the delivery month until their final settlement at the end of the month with the corresponding baseload, peakload, or off-peakload monthly index. Figure 10 illustrates this process of cascading.

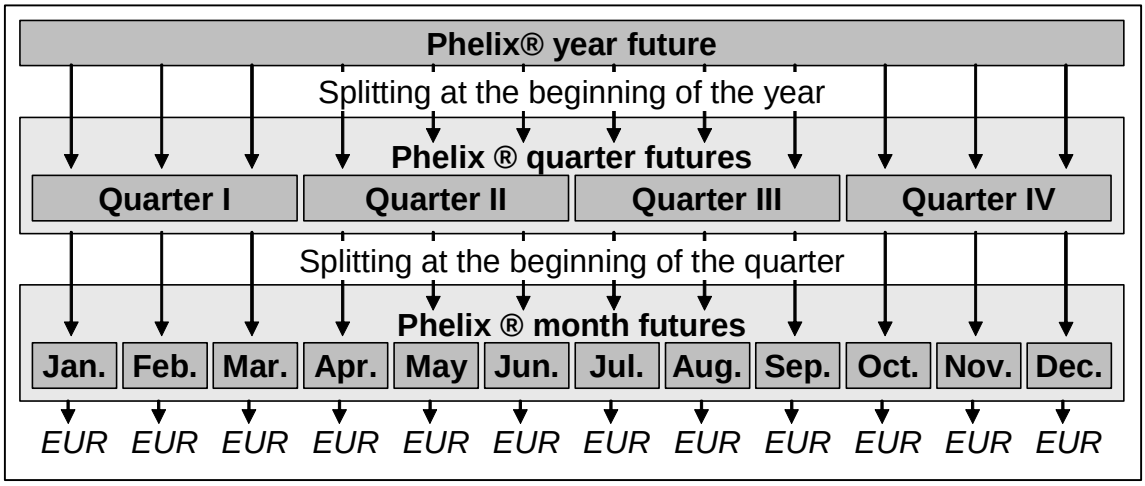

Figure 10: Phelix® futures and the process of cascading[323]

The Phelix® month futures are not cascading into week futures that are tradable during the delivery week until final settlement on the following Monday.[324] As for the month futures, it is always a cash settlement.[325] Only on request, admitted trading participants of the EEX have the option of a physical settlement. Whereby, the corresponding volumes are procured through price-independent bits on the EPEX Spot.[326]

To illustrate the effect of using Phelix® futures as an instrument for risk management, it is suggested to be the 11/30/2009 and the utility with the portfolio and its estimated value of TEUR 245,731 developed in appendix B tries to minimize the analysed price risk for the total year 2010. The current portfolio's value using MtM at 11/30/2009 referring to a spot market price of 36.94 EUR/MWh is TEUR 253,120 (see appendix E, Figure 27, p. 89). To avoid a strong decreasing of the portfolio's value due to the price risk, the utility's management decides to buy Phelix® year futures.

The forecasted minimum volume that needs to be procured on the EPEX Spot is 3,818 MWh/day.[327] Assuming a baseload share of about 2/3, the utility orders 100 Phelix® baseload year futures to cover a procurement of 2,400 MWh/day (100 futures * 24 h * 1 MWh) for 2010 with a total volume of 876 GWh (365 days * 2,400 MWh/day).

[323] Cf. Grichnik/Vortmeyer (2002), p. 390.
[324] Cf. EEX (2010c), p. 1.
[325] Cf. Grichnik/Vortmeyer (2002), p. 391.
[326] Cf. EEX (2010a), p. 14.
[327] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix B - Fictive portfolio.xls",table: Portfolio_Calculation.

Suggesting a futures price of 40 EUR/MWh this procurement is at TEUR 35,040 (876,000 MWh * 40 EUR/MWh). Due to the commitment regarding this 876 GWh, the portfolio's value changes because TEUR 35,040 is a fixed amount. Hence, the open position that needs to be procured on the EPEX Spot at forecasted 35.94 EUR/MWh decreased from 2,000 GWh to 1,124 GWh. Accepting a lower portfolio value of TEUR 3,557 at 11/30/2009 using MtM expresses the calculative costs of the Phelix® future. In return the VaR decreased by TEUR 1,342 to TEUR 32,561 or 13 % (see appendix E).
This example could express the effectiveness of using futures to fix prices. However, it also sensitized for the corresponding costs of unconditional forward contracts that can increase immensely,[328] in this case, due to further decreasing spot prices.

b) German Power Futures (French Power Futures)

A fulfilment of the future contract as physical settlement in Germany is possible with the German Power Futures and delivery in the network of the German TSO Amprion. Corresponding French Power Futures are traded with delivery in the grid of the French TSO. The physical settlement is the main difference to the Phelix® futures. Other differences are trading hours, fees, and contracting periods, but the principles of cascading or contract volumes remain. [329]

c) Phelix® Options

According to the objective of this thesis and its detailed elaboration in 3.3.2, options seem to be a promising tool to hedge the market price risks. According to part a), futures are appropriate to fix prices of the future. However, in case of a reverse development of the underlying's price as estimated, the owner of the future realizes losses, because he/she has to execute the deal at the contracted price under any conditions.[330] Referring to Figure 8 (p. 41), these costs could be extremely high and therefore contain using futures an inherent risk. Traders should not underestimate this risk.[331] Potential maximum losses of the long position of an option in contrast are capped at the paid premium for the option and the transaction costs (see 4.2.2.2).[332]
On the EEX, European options on the next five Phelix® month futures, six quarter futures, and three year futures are tradable. Delivery rates and contract volumes are orientated to the Phelix® futures. The options are usually settled in cash, but optionally also a physical settlement is possible.[333]

[328] Cf. Hull (2009), p. 761-763.
[329] Cf. EEX (2010a), p. 15.
[330] Cf. Schwarz (2006), p. 17.
[331] Cf. Cotter (2005), p. 491f.
[332] Cf. Bhattacharya (1987), p. 1.
[333] Cf. EEX (2010a), p. 16.

Even the use of Phelix® options can be illustrated on basis of the fictive portfolio. To be rentable in the supply of big industrial clients, the utility has to procure the power volumes including all costs at less than 0.1817 EUR/kWh (see appendix B, Figure 14, p. 81). Assuming fixed costs of 0.14 EUR/kWh (see appendix B, Figure 15, p. 82), the spot price to procure the volumes on the EEX must be lower than 0.0417 EUR/kWh (= 41.7 EUR/MWh). It is supposed to be the 11/30/2009 and the future price of a Phelix® Month future for March 2010 is at 37 EUR/MWh. A long call on the option costs a premium of 0.9 EUR/MWh. Transaction fees are at 0.012 EUR/MWh.[334] In total, the utility pays maximal 37.912 EUR/MWh (37 + 0.9 + 0.012 EUR/MWh) if using the option, which is in any case profitable. Hence, the price risk can be hedged effectively. If the spot price in March 2010 is at 35 EUR/MWh, the utility will allow the option of buying at 37 EUR/MWh to lapse and acquire the required volumes on the EPEX Spot. Including the premium paid for risk management, the utility buys at 35.912 EUR/MWh and is still profitable. If the average spot price of March is higher than 37 EUR/MWh, the utility uses the option at total 37.912 EUR/MWh in any case.[335]

4.2.2.4 Potential and Risks of Energy Derivatives

While explaining the use of derivative contracts on the EEX in the previous section, some risks of these instruments where already mentioned. In the following, potential and risks of energy derivatives are evaluated. These need to be considered in a risk management strategy, which is analysed in the next section 4.3,

The main advantage of using energy derivatives is the possibility to separate the immense price risk (see 3.2) from sales or purchase contracts of the utility's portfolio into manageable products.[336] However, due to the need of procurement at contracted transfer points respectively local delivery of the power to the end-customer at the demanded price and volume (see 3.3.1),[337] the exchange-traded standard future in most cases refers to other delivery conditions than the effective physical delivery. The different structure of power plants with the corresponding different cost structures (see Figure 2, p. 13) causes varying costs of power supply and consequently of power prices between the German regions.[338] As a result, the return of the future does not perfectly correlate to the loss in the specific region. This price development mismatch of the underlying asset and the derivative to hedge the risk of volatile market prices is

[334] Cf. EEX (2010a), p. 16.
[335] Cf. Hilpold (2009), p. 391.
[336] Cf. Brunet/Shafe (2007), p. 666.
[337] Cf. Eydeland/Wolyniec (2003), p. 10.
[338] Cf. Diekmann/Reichmann/Wobben (2008), p. 256.

called basis risk. It is the common risk of standardized future contracts.[339] As a big advantage, the credit risk (see 3.1) virtually does not exist due to the clearing services that are offered on organised exchanges.[340] Furthermore, the fungibility of futures makes it more likely to find other investors during the contracting period and resell the future or close the open trading position before delivery.[341]

The problem of the futures' typical basis risks can be at least partly solved by using forwards because of their individual contract design. Therefore, forwards include a distinct higher counterparty risk.[342] However, this risk can be minimized if using the offered OTC clearing services of the ECC.[343] Because of the lower basis risk and the possibility to reduce the counterparty risk, forward contracts are more common in the German electricity market as futures. The OTC clearing share at the total traded electricity volume of 1,025 TWh on the EEX Power Derivatives in 2009 was at 72%.[344]

The advantage of OTC versus exchanges based derivatives is the flexibility to create them according to their purpose with lower basis risks. Thereby, the development is only determined by imagination and creativity of the management (see 4.2.2.2). Hence, the necessary expert knowledge is also a big challenge in the electricity market.[345]

Options on futures or forwards contain comparable problems but, as mentioned in the previous section, the holder's maximum loss is capped.[346]

Besides these 'normal' risks of financial instruments, energy derivatives contain special risks due to the complexity of these products. It is essential to understand the pricing of power (see 3.1.3). The non-storable asset electric energy is more comparable to a complex portfolio of different operational, environmental, regulatory, and other issues, than to a classic underlying.[347]

Due to the extreme volatility, especially the usage of unconditional forward contracts is very risky, unforeseeable, difficult to manage, and with wide consequences. For example, the spot price jumped from the first to the second trading day in January 2010 from 21.05 to 33.12 EUR/MWh by 57%.[348] If the utility has a open position to sell power at 25 EUR/MWh on the second trading day, MtM still leads to a profit of 3.95 EUR/MWh one day before execution of the contract but only one trading day later it is a loss of 8.12 EUR/MWh or approximately 32 % (!!!) per forward contract.

[339] Cf. Golden/Wang/Yang (2007), p. 319.
[340] Cf. Hull (2009), p. 39.
[341] Cf. Fontanills (2008), p. 220.
[342] Cf. Eydeland/Wolyniec (2003), p.31f.
[343] Cf. ECC (2010), p. 3.
[344] Cf. EEX (2010a), p. 13.
[345] Cf. Kim (2007), p. 32.
[346] Cf. Bhattacharya (1987), p. 1.
[347] Cf. Eydeland/Wolyniec (2003), p. XII.
[348] Cf. EEX via DataStream (access: 06/03/2010).

4.2.3 Further Risk Management Instruments

The analysed risk management instruments contract design (see 4.2.1), especially to minimize the volume risk, and energy derivatives (see 4.2.2) to hedge price risks are the most effective instruments regarding the objective of this thesis. To enlarge the overview, further possible instruments for managing risks in the German electricity market are mentioned in the following.

A major risk factor is the high volatility of the electricity prices[349] analysed in 3.2 and the dependency of the risk management strategy on reliable forecasts as basis to optimize arrangements on the procurement side of the portfolio. Creating such forecast contains an information risk due to missing or wrong information or misinterpretations.[350] Generating, advancing, transferring, and storing of knowledge within companies to improve the usage of data and information opens a new field of research at this point.[351] The interconnection of this shortly characterised knowledge management with the risk management should sensitize for the intensive and difficult integration of a risk management in all parts of an enterprise.[352] A further analysis of knowledge management is beyond the scope of this thesis. However, it makes obvious that an all-embracing analysis of all potential risk management instruments is almost impossible, because to many fields of research, stakeholders, and other aspects are involved.

Concentrating on the determined risk of increased relevance according to 3.1, the credit risk that is indeed of minor interest (see 3.1.1) should not be ignored totally. Hence, an instrument to reduce the risk of non-payment by the end-customers can be a diligent screening of the counterparts.[353] Claim management offers methods to assess the clients regarding their solvency and willingness to pay,[354] but this is as the field of knowledge management going beyond the scope of this study.

In summary, this analysis of risk management instruments for power-trading utilities is not complete, but rather concentrates on the major risks: Volume risk and price risk. For a comprehensive examination of potential instruments, it is possible to refer to general literature on risk management such as Wolke (2008). In fact, the number of risk management instruments is only determined by imagination and creativity of the management, because the environment is constantly changing, strategies are adjusted, and risk management becomes a dynamic process that never ends.[355]

[349] Cf. Escribano/Peña/Villaplana (2002), p. 3.
[350] Cf. Todem/Stigler (2002), p. 172.
[351] Cf. Geiger (2006), p. 11.
[352] Cf. Lam (2003), p. 45.
[353] Cf. Todem/Stigler (2002), p. 173.
[354] Cf. Wolke (2008), p. 64f.
[355] Cf. Gibbs/DeLoach (2006), p. 35.

4.3 Risk Management Strategies

4.3.1 Possible Trading Strategies

This part illustrates how to use the analysed instruments, combine them, and optimize a utility's risk management strategy. In the first step, the top-management decides about the risk management policy. Thereby, the basic determination refers to the risk willingness and the intended risk-and-return goal.[356] There are three risk attitudes that reflect within potential risk management strategies. Risk-averse organisations accept costs to reduce risk. Risk-neutral companies decide based on the expected monetary value and risk-seeking enterprises accept risk to get chances to maximize the return.[357]

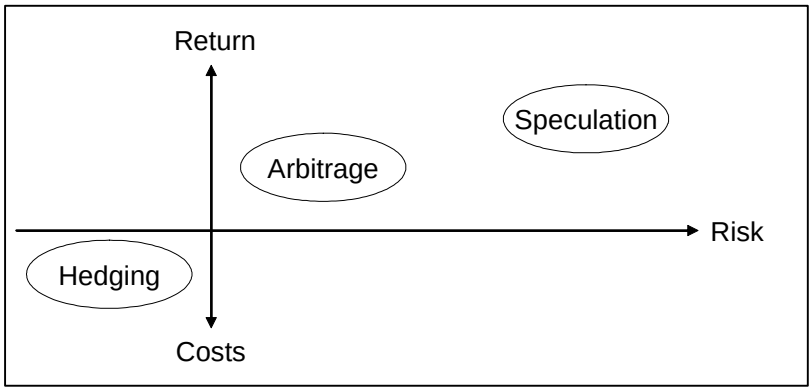

Figure 11: Scheme of possible risk management strategies[358]

a) Hedging

Following the intention of a managerial risk aversion, the objective of hedging is risk reduction in financial as well as non-financial areas. Derivatives are used to encounter the market price volatility or other aspects that negatively affect the portfolio's value and should compensate losses.[359] The result is a lower risk level. It could safe the company's ability to concentrate on its core business. An effective hedging policy can encourage loyalty and confidence of investors, managers, workers, suppliers, and clients. The exemplary benefit of such increased stakeholder goodwill can be cash flow stability due to customer loyalty, improvements in supply chain, or a stronger position to deal with mergers and acquisitions because of supporting investors.[360] These benefits must exceed the costs associated with the hedging. Transaction costs such as bank charges or fees and costs of monitoring the market or various opportunity costs are expenditures of this risk reduction without direct returns.[361]

[356] Cf. Pilipovic (2007), p. 430.
[357] Cf. Brown (2006), p. 32.
[358] Source: Pilipovic (2007), p. 431.
[359] Cf. Cortez/Schön (2009), p. 414.
[360] Cf. Michael (2008), p. 46f.
[361] Cf. Bartram (2000), p. 306.

There are two hedging methods with derivatives. If the underlying of the forward contract is the same asset whose price should be hedged, it is a pure-hedge. Cross-hedging occurs in the case of two different assets.[362] Therefore, hedging electricity price fluctuation with a Phelix® future is a pure-hedge because the underlying is also the electricity price. If the underlying of the forward contract to hedge the power price is for instance coal, it is a cross-hedge. Such a hedging is possible because a comparable price development of this commodity can be assumed due to the dependency of the German power price on the price of coal (see 3.1.3).[363] However, the development of even closely related assets is never identical. Hence, cross-hedging can only reduce but never eliminate the price risk.[364]

Within the German electricity market, hedging strategies crucially depend on market expectations regarding volatility and assumed development of the market prices. Main hedging strategy to hedge the portfolio of a power-trading utility (see 3.3.1) against losses in value are considered below and summed up in Figure 12.

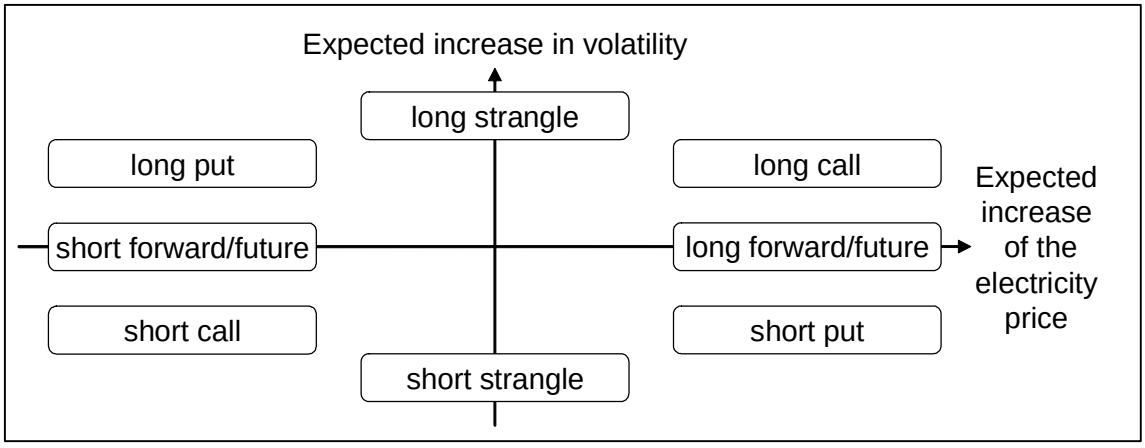

Figure 12: Possible hedging strategies[365]

In the case of high volatile electricity prices, according to 4.2.2.2 it is useful to cap potential maximal losses. Hence, the long position of an option seems to be adequate, because hedging against unprofitable price developments is possible and the costs of the hedging strategy are predictable and capped to the option's premium and transaction costs.[366] If the management of the utility expects an increasing electricity price, the company cinches an option to buy electricity at a fixed lower price (long call). Vice versa, in case of assuming a decreasing electricity price, it uses a long put to sell at a higher price with a profitable usage of the long position of the option.[367]

[362] Cf. Hull (2009), p. 54.
[363] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 117.
[364] Cf. Woo/Horowitz/Hoang (2001), p. 3.
[365] Source: Todem/Stigler (2002), p. 175.
[366] Cf. Bhattacharya (1987), p. 1.
[367] Cf. Mayer-Fiedrich (2009), p. 154.

If the utility's management does not expect strong price volatility, the potential maximal unexpected losses are also not so high. Therefore, there is no need to cap these potential losses and it is possible to reduce the risk management expenditures. Instead of options, futures respectively forwards that do not cost a premium can be used. The long position can assure the purchase of electricity on the EEX Power Derivatives or from an ESC at contracted lower power prices in case of an expected increasing price. The short position corresponding can assure higher prices for selling electricity. Hence, hedging with forwards and futures can reduce the risk but there is no guarantee that the outcome will be better due to the previously mentioned opportunity costs.[368]

Expecting decreasing price volatility opens possibilities to reduce the cost of risk management or even to gain profits. The short position contains the risk of very high losses in case of unexpected price fluctuations. If such movements are not anticipated, it is possible to gain the premium by selling options.[369] If the utility expects increasing electricity prices, a short put guarantees a gain amounting to the premium the holder paid. In case of increased prices, the holder allows the option to lapse and the utility realizes the profit.[370] Nevertheless, the utility as writer of the option also bears the risk of an unexpected price development. In case of a decreased electricity price, the utility has to fulfil its commitment to buy electricity at the strike price that could be much higher than the spot market price. The option's holder in contrast, profits from a high volatility (see above).[371] In the case of a forecasted decreasing power price, the utility can use a short call with corresponding chances and risks. This behaviour includes some speculation strategy characteristics considered in following part c).[372]

Furthermore, options enable a strategy called strangle. If the utility expects high price volatility, but could not create a reliable forecast on the development of the electricity price, the company can use a long strangle. The utility acquires the same number of puts and calls with identical underlying and maturity. To manage the high uncertainty regarding the price development on volatile markets consequently requires higher risk management expenditures due to the buying of put and call options. In the case of expected lower volatility, the price risk is lower (see 3.2) and the utility could sell call and put options with the same underlying and expiration date. Using such a short strangle can reduce risk management expenditures and maybe be used to gain profits with the option premium and hence contains speculative aspects.[373]

[368] Cf. Hull (2009), p. 7-10.
[369] Cf. Mayer-Fiedrich (2009), p. 154.
[370] Cf. Hilpold (2009), p. 391.
[371] Cf. Thomas/Schmidt (2005), p. 433.
[372] Cf. Mayer-Fiedrich (2009), p. 154f.
[373] Cf. Noll (2000), p. 250.

Reducing risks without additional costs in form of an option's premium might be possible with swaps. The basic idea is to use comparative advantages of the swap parties.[374] Unlike the typical plain vanilla swaps (see 4.2.2.2), a utility can use a commodity swap that is in essence a series of forward contracts with different expiration dates and same delivery prices. At the end of each period the utility pays the preagreed volatility and hence can plan price fluctuations and therefore reduce the price risk. The ESC as potential counterpart of the forward agreement pays the real volatility during that period. The ESC makes a profit in case of a lower historical than preagreed price volatility. In contrast, with this volatility swap the utility has capped potential losses at the level of the contracted volatility.[375] Hence, the remaining price risk bears the ESC.

b) Arbitrage

In its simplest form, arbitrage is defined as a risk-free profit generated by exploiting differences between prices of the same commodity on different markets.[376] In case of the German electricity market, this could be price differences between the exchange and OTC traded power that enable the traders a risk-free intermediary trade. However, even such opportunities effect a permanent harmonization of OTC and exchange prices.[377] Hence, the spot price on the EEX is accepted as reference price in large parts of Europe (see 3.1.2).[378] It is also theoretically possible to realize arbitrage profits on the EEX power derivatives by using price differences between futures prices of contracts with different contracting periods such as Phelix® year or quarter futures that have the same expiration date. To avoid this, the EEX reserves the right to adjust the settlement prices in order to achieve a market free from arbitrage possibilities.[379]

Previous statements illustrate that such pure arbitrage profits are theoretically possible, but in the case of electricity forbidden by EEX regulations or not profitable especially because of the non-storability of power that does not allow intertemporal arbitrage and forces to an immediate execution of the deals.[380] Furthermore, electricity is a grid-bounded commodity. This means transmission losses on long distances and potential bottlenecks due to limited capacities of the power grid. Hence, also arbitrage between different locations is almost not possible.[381] Nevertheless, it might be possible, to realize a risk-free profit via a skilful composition of the utility's portfolio with the intention

[374] Cf. Wolke (2008), p. 100f.
[375] Cf. Hull (2009), p. 173.
[376] Cf. Hausmann/Diener/Käsler (2002), p. 50.
[377] Cf. Jahn (2008), p. 302.
[378] Cf. EEX (2010a), p. 3.
[379] Cf. EEX (2008), p. 8f.
[380] Cf. Borenstein, et al. (2008), p. 354.
[381] Cf. Wilmschulte/Wilkens (2004), p. 123.

of risks that compensate each other.[382] Part 4.2.1 indicates such an arbitrage portfolio. Reminding, a well-conceived contract design can lead to a compensation of risks on the procurement and sales side of the portfolio, which results at least partly in risk-free trading profits. Therefore, in contrast to the hedging strategy, using arbitrage keeps the risk level low. It does not reduce single risk but rather causes compensation. On the other hand, the costs of this strategy are lower.[383] However, as discussed before, the possibilities of arbitrage are limited and therefore focussing only on such a risk management strategy in case of the assumed risk adverse power-trading utility might not lead to sufficient results.

c) Speculation

Speculation follows the intention of taking high risks in the hopes of high rewards.[384] By speculating on increasing or decreasing market prices, financial instruments can be used with the intention to maximise profits and not only to reduce risks. Such a strategy is not based on the risk management intention of reducing the risk or fixing a potential maximum loss (see 4.1),[385] but rather comprises besides the risk of potential losses also the chances. Speculators not only want to avoid negative effects of price volatility, they want to benefit from fluctuations. Objective of such a risk management strategy is the optimization of the risk-and-return ratio. Thereby, speculators can use forwards and futures with high potential gains as well as losses or options with the limited maximum loss at the amount of the paid premium (see 4.2.2.2).[386]

In summary, the choosing of the risk management strategy depends on the individual objective of the management of a company regarding its risk-and-return targets.[387] In the context of this study, a risk adverse utility is assumed (see 4.1) that uses financial contracts primary to reduce risks within its portfolio and not to gain profits. Therefore, an optimal strategy is a combination of arbitrage and hedging to meet risk management objectives and simultaneously minimize the costs of the strategy. The next section analyses how to realize such a management strategy.

[382] Cf. Hausmann/Diener/Käsler (2002), p. 50.
[383] Cf. Pilipovic (2007), p. 431.
[384] Cf. Géczy/Minton/Schrand (2007), p. 2405.
[385] Cf. Bakshi/Cao/Chen (1997), p. 2006.
[386] Cf. Hull (2009), p. 11-14.
[387] Cf. Pilipovic (2007), p. 431.

4.3.2 Realization of Risk Management Strategies

The use of the risk management instruments analysed in 4.2 depends on the possible strategies characterised before. Generally, three common ways to handle the risks identified in third chapter can be distinguished. To follow the chosen strategy (see 4.3.1) the management has to decide whether to avoid, reduce, or accept risks.[388]

The simplest way to manage risks is to avoid them but without risks, economic success is not realistic. Hence, avoiding risks cannot be the only way to realize a risk management strategy. Furthermore, it refers to singe risks.[389] The managers of the utility should be familiar with the company's risks and debate freely about them in order to make decisions as to weather it needs to be avoided in any case, perhaps because of its potential immense negative effect or if other strategies are possible.[390] A special form of avoiding risks is the risk limitation. Risks are accepted up to a predefined limit but starting at that level, they are avoided completely.[391] As a result, this strategy minimizes the total risk level by avoiding single risks and leads over to a strategy of risk reduction.

Reducing risks aims primarily at the probability of occurrence and/or at the potential amount of loss. Minimizing one or both of these factors minimizes the total risk level.[392] The utility has no influence on the probability of an unprofitable electricity price development because it is a price-taking market participant (see 4.1).[393] On the other hand, it is possible to minimize the potential losses of the portfolio's value by using derivatives according to the hedging strategies analysed in the previous section.

Furthermore, a special form of risk reduction is risk diversification. Not the reducing of both factors probability and potential loss of each single risk but instead a reallocation between them is the aim in order to compensate risks and reduce the total risk level.[394] This diversification effect can be illustrated on the basis of the sales side of the utility's portfolio (see 3.3.1). Instead of concentrating on one end-customer group of 550,000 two-person households, the utility provides power for five groups of end-customers with total 1,625,000 customers (see appendix B, Figure 14, p. 81). The probability of customer default increases by almost three (1,625,000/550,000), but the relative potential loss at the total portfolio's value decreases accordingly.

[388] Cf. Michael (2008), p. 47.
[389] Cf. Siebold (2006), p. 30.
[390] Cf. Buehler/Freeman/Hulme (2008), p. 98f.
[391] Cf. Wiedemann (2000), p. 383.
[392] Cf. Siebold (2006), p. 31.
[393] Cf. Fleten/Wallace/Ziemba (2002), p. 72.
[394] Cf. Wolke (2008), p. 79.

The opposite of such a strategy is risk concentration with a decrease of the probability of occurrence and corresponding increases of potential losses and might be another way to realize the risk management strategy.[395] Concentrating on the core business and key customer groups could increase the performance and enable to remain competitive in the increasing competition on deregulated electricity markets.[396] Thereby, it is possible to encounter the higher potential losses with the risk management techniques described in this thesis.

Another way of risk reduction is not to change the probability of occurrence or the amount of potential losses but to transfer the risks to a third party. The most common example for this strategy is the signing of an insurance agreement. However, risk transfer without insurances also is possible.[397] In case of the utility, contract clauses with ESCs that allows interrupting the power purchase a several times (see 4.2.1)[398] are such a risk transfer because the volume risk based on volatile customer's demand is forwarded to the ESC.

A further way to reduce the risk is risk transformation, the replacement of one risk with another usually minor and more acceptable risk.[399] An example is the acceptance of the credit risk in case of an OTC forward contract to replace the basis risk of exchange-traded derivatives.[400] This characterisation of ways to reduce the risks is not conclusive, rather it sensitized for the various possibilities that are similar to possible hedging strategies (see 4.3.1) only limited by the management's imagination.[401]

Finally, as mentioned at the beginning of this section, achieving economical success requires also accepting a degree of risks. If the company waits until all the information has been handled and all the uncertainty is gone, the opportunity to gain profits might also be gone.[402] Important is to be aware of the risk acceptance. Unknowingly entering risks creates new uncertainty and hence disables an effective risk management. Therefore, a correct identification, measurement, and evaluation of risks (see chapter 3) is important to ensure that the benefit of risk acceptance is higher than the negative potential of the risk and that the other above-mentioned approaches to realize the strategy are not more profitable.[403]

[395] Cf. Siebold (2006), p. 31.
[396] Cf. Sueyoshi/Goto/Shang (2009), p. 4589f.
[397] Cf. Altenähr (2008), p. 122.
[398] Cf. Ross/Kolos/Tompaidis (2006), p. 627.
[399] Cf. Siebold (2006), p. 32.
[400] Cf. Golden/Wang/Yang (2007), p. 319.
[401] Cf. Kim (2007), p. 32.
[402] Cf. Platt (2004), p. 11.
[403] Cf. Siebold (2006), p. 33.

4.4 Problems and Limits of Power Trading in the German Electricity Market

After the assessment of the identification, measurement, and evaluation of risks within the third chapter and a final critical résumé of the characterised methods in 3.4, this chapter illustrated how to handle the risks in spite of such problems. Not one best-way but rather the combination of different techniques and instruments also considering individual risk willingness as well as company policy and situation are the key to establish an efficient risk management strategy for a power-trading utility. Even if several problems and characteristics are already analysed beforehand, this final paragraph of section 4 should sensitize for problems and limits of power trading in the German electricity market in order to round up the analysis of the risk management process.

Important to mention is that the common opinion that electricity is a homogeneous commodity[404] is doubtful. It is not, because it differs in voltage, which depends on the kind of power grid, or the production and delivery region[405] with the corresponding price differences mentioned in 4.2.2.4. Consequently, in spite of a pure hedge with Phelix® futures, energy derivatives can never eliminate the basis risk completely. Hence, even OTC financial contract often contain a remaining basis risk.

Due to MtM and the necessity to pay the daily variance in value of open positions on the margins account of the ECC,[406] the utility has an individual liquidity risk. Imagine a utility that wants to hedge with a long Phelix® future to fix the price of the future supply with electricity at prices that enable a profitable resale to the end-customers (see 4.2.2.3 and 4.3.1). On signing day, the ECC requires the utility to deposit the initial margin. If the future price decreases, the utility realizes a loss that reduces this margin account (see 3.3.2.1).[407] The objective of the ECC is to cover any possible losses in case of default of a clearing member with a confidence level of more than 99%.[408] To ensure this, the margin account is not allowed to become negative. If the future price decreases stronger than assumed and the predefined minimum amount on the margin account, called maintenance margin, is exceeded, the utility has to deposit additional funds that are known as variation margin.[409] Payments of initial and variation margin have to be made on signing day respectively at the end of each trading day. Furthermore, the ECC only accepts high quality securities as an alternative to cash.[410]

[404] Cf. Bushnell/Mansur/Saravia (2008), p. 238.
[405] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 111f.
[406] Cf. ECC (2010), p. 6.
[407] Cf. Hull (2009), p. 26f.
[408] Cf. ECC (2010), p. 6.
[409] Cf. Hull (2009), p. 27.
[410] Cf. ECC (2010), p. 6.

End-customer payments to the utility usually take place after the delivery of power. Hence, the outflow of cash is markedly before the corresponding inflow. This can cause the temporary inability to pay and consequently the illiquidity of the utility.

This example also illustrates a further chance and problem of a power-trading utility in the German electricity market. The manifold trading possibilities on spot and future markets require a well-founded knowledge, extensive information, experience, and trading skills to avoid liquidity bottlenecks and maybe optimize the profits with strategies such as speculation.[411] Referring to the knowledge management mentioned in 4.2.3, it could be possible to acquire such an expertise for example through cooperation[412] with investment banks that should possess knowledge and skills within this area. Nevertheless, there are differences between the market participants in the German electricity market. The power producing companies (ESC) have an advantage regarding their information, because they knew production data and costs exclusively. Such insider information regarding these price influencing factors (see 3.1.3) are not available for power-trading utilities.[413] This causes a competitive disadvantage even in the case of cooperation with investment banks.

A related problem on deregulated energy markets is the risk of price manipulations due to the superior market position of some big companies.[414] A spectacular case in the German electricity market was the investigation against E.ON in 2006. There was no judgement against this ESC due to the accommodation of E.ON. Even so, the inquiry report of the BKartA mentioned adjusting screws such as the retention of production capacities that suggest the assumption of price manipulation in the years 2002 to 2007.[415] Worldwide, the case of ENRON, the former largest energy trader in the world, is the most famous example for this immense risk in the electricity sector. On the deregulated US electricity market, ENRON traded with more than 2,000 different financial products and build large speculative positions. ENRON used its market power to manipulate California energy prices in 2001. On top of this came the manipulation of the company's balances and traders lost the faith in ENRON. The insolvency of this power-trading company in 2002 was the biggest corporate bankruptcy in the US history to that point.[416] Market deregulation slowed down and new rules such as the Sarbanes-Oxley Act (SOX) arose out of such scandals as the ENRON case.[417]

[411] Cf. Géczy/Minton/Schrand (2007), p. 2419f.
[412] Cf. North (2005), p. 69f.
[413] Cf. Becker (2010), p. 409.
[414] Cf. Benner (2009), p. 373.
[415] Cf. Becker (2010), p. 399f.
[416] Cf. Brunet/Shafe (2007), p. 665-681.
[417] Cf. Feldmann/Read (2010), p. 267.

Another problem not to be underestimated is an operational risk due to personnel and organisational difficulties. Some organisational frameworks offer an incentive to build speculative positions. In the case of high profits, employees often participate directly via the compensation system. In the case of high losses, the system usually guarantees a minimum wage. The worst case in most scenarios for the employee might be loosing the job.[418] A situation where employees do not participate with the same degree on losses as on profits could motivate to actions that run contrary to the utility's risk management strategy (agency risk).[419] If inadequate control mechanisms are added to this situation or the employee has a risk-seeking nature, this agency risk of internal speculation arises.[420] In the past, this effect occurs regularly. One of the most spectacular cases is the collapse of the Barings Bank due to the activities of only one of the company's traders.[421] Not only in the banking sector, where it is suggested that one reason for the worldwide financial crises starting in 2007 / 2008 is such a bonus system encouraging some banker to take high risks,[422] but this problem could also be immense in other branches.

Within this closing analysis of main problems and limits of a power-trading utility in the German electricity market, the model misspecification risk needs to be mentioned. All possible risk management strategies are based on a reliable forecast of electricity consumption and price characterised mainly in 3.2. Due to the analysed high complexity of electricity forecasts, mathematic mistakes within the model could occur (model risk). In addition, it is more likely to assume basic parameters that are wrong or at least doubtful (misspecification risk).[423] Firstly, there are doubts about how current values of some parameters are composed and which variables really influence these factors. Secondly, there is a considerable uncertainty about future developments of the parameters. Hence, a power-trading utility company could pay severe penalties if the models or their assumptions are misspecified.[424]

This is no concluding characterization of all problems and limits for a power-trading utility. It rather concentrates on the main risks from the authors point of view to sensitize for the appropriate due diligence while trading on the German electricity market even if a comprehensive risk management process is established.

[418] Cf. Tishkin (2010), p. 11.
[419] Cf. Kaserer, et al. (2008), p. 5.
[420] Cf. Auer (2008), p. 20.
[421] Cf. Stein (2000), p. 1215.
[422] Cf. Tishkin (2010), p. 9-12.
[423] Cf. Rudolph (2008), p. 727f.
[424] Cf. Friedman (2000), p. 34.

5 Conclusion

This thesis analyses the possibilities of a power-trading utility company to create its risk management process in order to confront the changing framework in the German electricity market and provides a general overview of such a risk management system. To answer the research question, this study is divided to analyse three sub-questions.

a) Liberalization of the German electricity market caused a changing framework

The analysis of the dynamic environment in chapter 2 illustrates the rising chances for utilities to gain profits. Besides the opening of the former exclusive sales territories of the ESCs that opens new markets for utility companies, they can also benefit from positive price developments. On the regulated electricity market the companies where bounded to long term agreements containing state-controlled prices.[425] Hence, positive effects of decreasing acquisition prices remained with the ESCs. Besides these possibilities, the market liberalization causes new challenges for utilities with enlarged requirements and tasks for the risk management systems. It becomes necessary to identify, measure, and evaluate the various risks and finally develop a risk management strategy that encourages economic success.[426]

b) Identification, evaluation, and measurement of the new risks

During the analysis of the market liberalisation, the problem of establishing real competition in the oligopolistic German electricity market dominated by the former monopolistic companies already became obvious. Potential price manipulation is still a risk for a utility that should not be underestimated.[427] However, as analysed in chapter 3, the main risk factor occurring in the course of deregulation is the extreme volatility of market prices especially due to the non-storability of power (see 3.1). Beside these non-influenceable risk categories, further risks that utilities cannot influence such as the price of fossil sources increase the uncertainty within this business environment.

To confront these problems, complex models to forecast electricity prices in order to reduce this uncertainty emerged. Differentiated models can analyse and explain price developments ex post. Especially due to the existence of spikes, forecasting power prices remains a problem. Practical models only provide indicators assessing the process of arrival of a spike, but they do not deliver absolute reliable results.[428]

The relevance of this problem becomes obvious while using techniques such as sensitivity analysis or VaR to measure the risks. These methods are legally approved,

[425] Cf. Hensing/Pfaffenberger/Ströbele (1998), p. 171.
[426] Cf. Todem/Stigler (2002), p. 170.
[427] Cf. Becker (2010), p. 399.
[428] Cf. Cuaresma, et al. (2002), p. 14.

enable a risk quantification, and provide understandable results,[429] but their outcomes comprise a wide range of results depending on the chosen model and assumed parameters.[430] Combining different methods and implementing stress-testing systems are suggested possibilities to encounter this problem and guarantee due diligence.[431]

c) Potential risk management strategies and their realization

The in 3.1.1 identified superior risks of a power-trading utility in the German electricity market are the volume and price risk. Therefore, chapter 4 concentrates on the analysis of risk management strategies regarding these factors.

As illustrated in 4.2, a flexible contract design[432] as well as synchronising contracting periods and reference prices on the procurement and sales side of the utility's portfolio could cause some kind of natural hedge for the volume risk. This can be forwarded to the ESC in return of accepting slightly higher risk management expenditures.

Derivatives are optimal risk management instruments to confront the immense price risk. The use of financial instruments requires knowledge, information, experience, and trading skills[433] as well as innovative ideas and flexibility.[434]

In summary, sustainability and future success of a power-trading utility company in the German electricity market depends among other things on its ability to establish an integrated and dynamic risk management process that can be adjusted to environmental changes if necessary.[435] Independent of the chosen risk management strategy (see 4.1) the utility's success will depend on the flexibility and up-to-date decisions of its management. [436]

Power trading in liberalized markets is a relatively young field of research. Hence, this thesis also leaves many questions unanswered. Thereby, in the focus of the policy is especially the question, how to establish more competition in the German market in spite of the four market dominating companies E.ON, EnBW, RWE, and Vattenfall. As indicated in 3.2, potential for improvements in the field of mathematic research is the further development of forecasting models for electricity prices. Finally, the challenge for the economic practice and research of creating and evaluating constantly arising risk management techniques and innovative derivatives are only some examples of further steps in the development and the analysis of deregulated power markets.

[429] Cf. Prokop (2008), p. 478f.
[430] Cf. Rudolph (2008), p. 727f.
[431] Cf. Al Janabi (2009), p. 27.
[432] Cf. Ross/Kolos/Tompaidis (2006), p. 627.
[433] Cf. Géczy/Minton/Schrand (2007), p. 2420.
[434] Cf. Kim (2007), p. 32.
[435] Cf. Gibbs/DeLoach (2006), p. 35
[436] Cf. Wang/Min (2008), p. 365.

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V. Appendix

A. Overview – Daily Average Phelix® from 01/01/2002 to 05/28/2010

Figure 13 shows the average, maximum, and minimum price of electricity on the EEX, the daily average Phelix® baseload monthly index, from 01/01/2002 to 05/28/2010.

[EUR/MWh]	Average price	Maximum price	Minimum price
2002	23.26	52.09	7.94
2003	28.63	40.52	3.12
2004	29.08	40.79	19.22
2005	45.48	114.06	19.44
2006	48.99	87.31	21.46
2007	35.95	67.38	5.80
2008	65.92	93.56	21.03
2009	39.22	60.01	18.33
01-05/2010	41.08	45.88	21.05

Trading days [t]	2,194
Overall maximum price [EUR/MWh] (12/01/2005)	114.06
Overall minimum price [EUR/MWh] (05/01/2003)	3.12
Average price 01/01/2002 to 05/28/2010 [EUR/MWh]	39.63
Median price 01/01/2002 to 05/28/2010 [EUR/MWh]	36.16

Figure 13: Phelix® baseload monthly index – overview average daily prices[437]

B. Fictive Example – Portfolio of a Power-Trading Utility

To illustrate the risk management strategy of a power-trading utility, a fictive portfolio representing such a company based on historic data and assumptions is suggested.

a) Sales side of a utility's portfolio

The sales side of the electricity-related part of the portfolio consists of open contracts. Thereby, the individual demand of the customer is relevant (see 3.3.1)[438] and therefore this volume risk is one main risk factor for following VaR estimation (see appendix C). Customers are divided in the two major groups, industry and households.[439] These are subdivided into three kinds of households and two types of industries according to dimensional characteristics. The number of customers per customer group, average power demand, and base load per customer are fictive assumptions.

On basis of these expectations, the total estimated demand as well as estimated base load is calculated via simple multiplication. Finally, by suggesting different contract

[437] Source: EEX via DataStream (access: 06/03/2010), *local link*: "Wittenberg; Appendix A - Phelix _MonthBase.xls", table: Av.,Max.,Min._Prices.
[438] Cf. Kolks (2003), P. 298.
[439] Cf. von Hirschhausen/Cullmann/Kappeler (2006), p. 2563.

prices for each customer group that oriented on current end-customer prices in Germany[440] it is possible to calculate a potential portfolio return.

Customer group	Number of customers [in 1,000]	Average power demand / customer [MWh/a]	Average base load / customer [MWh/a]	Total estimated demand [MWh/a]	Total estimated base load [MWh/a]	Contracted price [EUR/kWH]	Total estimated return [TEUR]
Households							
2 Persons	550	2.50	1.10	1,375,000	605,000	0.2200	302,500
3 Persons	375	3.50	1.52	1,312,500	570,000	0.2100	275,625
4 Persons	600	5.00	2.00	3,000,000	1,200,000	0.2050	615,000
Industry					0		
Small	75	37.50	10.00	2,812,500	750,000	0.1900	534,375
Big	25	60.00	35.00	1,500,000	875,000	0.1817	272,500
Total				**10,000,000**	**4,000,000**		**2,000,000**

Figure 14: Sales side of the electricity-related part of a utility's portfolio[441]

b) Procurement side of a utility's portfolio

To fulfil the obligations of the open contracts with each customer within the portfolio described above, it is necessary to provide the needed volumes at the right times and places[442] based on electricity forecasts (see 3.2.2).

Referring to 3.3.1 most of the customer's demand should be satisfied on the basis of bilateral contracts that are fixed OTC with ESC (see Figure 5, p. 25). Hence, the utility concludes a baseload contract covering the estimated basis demand of 4,000 GWh per year (see Figure 14) for the 24 hours of each day, a peakload contract covering the hours 9 am to 9 pm,[443] and a seasonal contract covering typical periods of the year with higher power consumption. The remaining 20% of the estimated volumes are hard to forecast and therefore should be purchased in short term on the EPEX Spot.

Due to the take-or-pay clauses in the bilateral contracts,[444] the utility can push through relatively low power prices depending on the purchase quantity. The estimated spot market price is the average daily electricity price of the Phelix® baseload monthly index from 01/01/2002 to 05/28/2010 (see Figure 13, p. 80). Besides this 'pure' electricity procurement costs, a utility also has to cover further typical expenditures such as material costs, personnel costs, depreciation, and other things.[445] To consider these within the portfolio in order to be able to make a statement regarding the profitability of

[440] Current electricity prices in Germany for different kind of end-customers can be compared via several online offers such as http://www.strompreisvergleicher.com (access: 07/19/2010, 4:13 pm), http://energie.check24.de (access: 07/19/, 4:21 pm), or http://www.tarifvergleich.de (access: 07/19/2010, 4:26 pm).

[441] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix B - Fictive portfolio.xls",table: Overview_Portfolio.

[442] Cf. Kolks (2003), P. 298.

[443] Cf. EEX (2010a), p. 6.

[444] Cf. Bundekartellamt (BKartA) (2010), p. 1.

[445] Cf. § 275 HGB.

the utility, these costs are considered in form of other cost. To avoid falsifications they are added as equal cost blocks to the single arrangements with the ESC, as well as to the volumes procured on the EPEX spot. Finally, the total costs can be estimated via a simple multiplication of the estimated volumes and cost blocks.

Arrangement	Volume [MWh]	Price [EUR/kWH]	Procure-ment cost [TEUR]	Other costs [EUR/kWh]	Total costs [TEUR]
Baseload contract	4,000,000	0.0330 *)	132,000	0.140	692,000
Peakload contract	3,000,000	0.0350 *)	105,000	0.140	525,000
Seasonal contract	1,000,000	0.0380 *)	38,000	0.140	178,000
Spot market volumes	2,000,000	0.0396 **)	79,269	0.140	359,269
Total	**10,000,000**		**354,269**		**1,754,269**

*) Contracted price as the result of bilateral negotiations with ESC
**) Estimated spot price: Average historical Phelix® baseload monthly index from 01/01/2002 to 05/28/2010

Figure 15: Procurement side of the electricity-related part of a utility's portfolio[446]

The estimated value of this portfolio is TEUR 245,731 (2,000,000 – 1,754,269). Besides the accuracy of the assumptions, this value especially depends on several risk factors (see 3.1), which can be aggregated to the main variable of the fluctuating demand on the sales side and the volatile spot market prices on the procurement side. These factors are analysed in detail in sections 3.3.2 and 3.3.3 and the corresponding appendix C respectively appendix D.

However, to enable such an analysis referring to the objective of this study with a scope on daily fluctuation (see 3.3.2), it is necessary to allocate sale and procurement. In this fictive example, a period of one year is suggested.

a) Sales allocation

The estimated baseload of 4,000 GWh per year (see Figure 14, p. 81) is linear distributed over the 365 trading days. The remaining 6,000 GWh of that year are distributed accordingly to part 3.2 and consider the typical seasonal fluctuations portioned into months and the weekly volatility of demand.[447] This distribution incorporates that the daily demand on weekdays is higher than on weekends.[448] This fact can be proven by empirical data of ENTSO-E.[449] Its statistics confirms that the German average daily power consumption 2009 from Mondays to Fridays is higher than on Saturdays and Sundays (see Figure 16, p. 83).

[446] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix B - Fictive portfolio.xls", table: Overview_Portfolio.
[447] Cf. Wilkens/Tanev (2006), p. 300.
[448] Cf. Grichnik/Vortmeyer (2002), p. 387; Huurman/Ravazzolo/Zhou (2007), p. 5.
[449] Cf. ENTSO-E, online on the internet: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database access: 7/21/2010, 12:37 pm.

Average electricity consumption in Germany 2009		
Weekday	**Absolute [GWh]**	**Relative**
Mondays	67,979	15%
Tuesdays	70,090	15%
Wednesdays	70,226	15%
Thursdays	70,384	15%
Fridays	67,371	15%
Saturdays	58,369	13%
Sundays	53,808	12%
Total 2009	458,228	100%

Figure 16: Average weekly electricity consumption in Germany 2009[450]

To determine the seasonal fluctuations divided into the twelve month of the year the historic data of the power demand in Germany from 2002 to 2009 provided by the European Commission online in the Eurostat database is used. It confirms the thesis of seasonality (see 3.2) and shows that the average consumption in the second and third quarter is clearly lower than in the colder months from October to March.

Average monthly demand 2002 to 2009:												
[in GWh]	**M01**	**M02**	**M03**	**M04**	**M05**	**M06**	**M07**	**M08**	**M09**	**M10**	**M11**	**M12**
2002	53,619	45,892	49,676	50,420	45,697	44,042	45,218	45,324	46,475	49,841	50,883	51,804
2003	53,902	51,292	51,380	46,764	46,533	44,875	47,625	45,559	46,704	49,638	49,928	50,156
2004	51,416	49,168	51,897	46,751	46,660	45,559	46,904	45,712	46,021	49,361	51,447	52,599
2005	50,696	49,930	51,169	47,826	46,369	46,168	46,275	45,738	47,038	48,325	51,178	51,728
2006	55,107	49,725	52,514	46,321	45,111	45,312	47,756	45,692	45,682	47,774	48,662	48,315
2007	47,544	46,569	48,973	44,479	45,619	45,262	45,019	45,946	44,561	49,156	49,012	48,090
2008	48,704	47,800	46,601	48,202	45,459	44,668	45,630	44,157	45,487	47,266	46,177	47,129
2009	49,893	44,712	45,848	40,558	40,292	39,976	41,611	41,167	41,891	44,807	43,522	46,691
Total	410,881	385,088	398,058	371,321	361,740	355,862	366,038	359,295	363,859	386,168	390,809	396,512
Average	51,360	48,136	49,757	46,415	45,218	44,483	45,755	44,912	45,482	48,271	48,851	49,564

Figure 17: Average monthly electricity demand in Germany 2002 - 2009[451]

Basing on this empirical data it is possible to allocate the estimated fluctuating demand of 6,000 GWh per year. Finally, adding the linear distributed baseload demand and the volatile consumption provides a demand curve of one year separated in 365 trading days.

This simulated trend of the yearly demand enables an approximate, but for the purposes of this thesis sufficient distribution of the total return of TEUR 2,000,000 (see Figure 14, p. 81) on each single day of the analysed year (see Figure 19, p. 85).

[450] Source: ENTSO-E, online on the internet: https://www.entsoe.eu, access: 07/21/2010, 3:09 pm; *local link*: "Wittenberg; Appendix B - Fictive portfolio.xls", table: ENTSOE_Overview_Day.

[451] Source: European Commission (Eurostat), online on the internet: http://epp.eurostat.ec.europa.eu, access: 07/21/2010, 12:37 pm; *local link*: "Wittenberg; Appendix B - Fictive portfolio.xls", table: EUROSTAT-Overview_Month.

b) Procurement allocation

To create a realistic portfolio of a power-trading utility with the objective to analyse risk management strategies and risk measurement tools such as VaR it is possible to use a similar approach as for the sales allocation to distribute the necessary procurement volumes on the 365 trading days.

It is suggested, that managements of ESCs and utilities know about the differences within the weekly consumptions and considers different demand volumes on working days and weekends. Hence, to distribute the weekly supply, the same empirical basic data as for the sales allocation is used (see Figure 16, p. 83).

According to the seasonal demand, the historical data of the supply with electricity in Germany from 2002 to 2009 provided by the European Commission online on the Eurostat database is used to determine the seasonal fluctuations in production.

Average monthly supply 2002 to 2009: [in GWh]	M01	M02	M03	M04	M05	M06	M07	M08	M09	M10	M11	M12
2002	55,411	47,051	49,838	49,656	44,025	42,352	43,958	43,390	44,567	50,478	49,832	51,703
2003	54,209	51,258	52,282	47,830	45,557	44,055	46,024	45,753	47,311	52,336	50,472	51,637
2004	52,854	51,508	53,372	47,940	45,259	44,026	44,656	44,351	45,724	49,605	52,139	54,700
2005	53,230	52,092	53,461	49,121	44,889	44,274	45,422	43,687	45,331	48,834	52,021	54,623
2006	58,316	52,883	55,612	47,615	44,802	45,496	46,963	44,989	45,866	49,318	50,614	52,487
2007	51,142	48,724	51,683	45,833	45,691	44,937	44,229	44,647	45,008	50,625	52,057	52,804
2008	52,597	50,957	50,607	50,457	45,959	43,449	44,251	43,939	46,286	50,136	48,871	49,869
2009	52,248	46,269	46,477	40,951	39,071	40,564	41,361	40,833	42,592	46,213	46,702	49,959
Total	430,007	400,742	413,332	379,403	355,253	349,153	356,864	351,589	362,685	397,545	402,708	417,782
Average	53,751	50,093	51,667	47,425	44,407	43,644	44,608	43,949	45,336	49,693	50,339	52,223

Figure 18: Average monthly electricity supply in Germany 2002 - 2009[452]

Similar to the allocation of the portfolio return it is possible to allocate the costs of the OTC contracts of TEUR 275,000 (see Figure 15, p. 82) on each day of the year.

As mentioned above, the remaining daily volumes are procured on the EPEX Spot at an estimated Phelix® of 0.0396 EUR/kWh (see Figure 15, p. 82). This also enables the distribution of the costs of the spot market procurement of TEUR 79,269 (see Figure 15, p. 82). Adding the other fixed costs of TEUR 1,400,000 (10,000,000 MWh * 0.014 EUR/kWh) by assuming a linear daily accruement it is possible to allocate the complete costs of the electric procurement on the 365 trading days. By subtracting these costs from the returns mentioned above a profit per day can be calculated.

Figure 19 (p. 85) shows an extract of the table with the characterised calculations. Furthermore, it summarizes this appendix and provides a detailed overview of the fictive example of a power-trading utility's portfolio that builds the basis for further calculations (see 3.3.2, 3.3.3 , appendix C and D).

[452] Source: European Commission (Eurostat), online on the internet: http://epp.eurostat.ec.europa.eu, access: 07/21/2010, 12:37 pm; *local link*: "Wittenberg; Appendix B - Fictive portfolio.xls", table: EUROSTAT-Overview_Month.

Day	Month	Week day	Baseload demand [MWh]	Fluctuating demand [MWh]	Total demand [MWh]	Total Return/day [TEUR]	Supply OTC [MWh]	Cost/day OTC [TEUR]	Supply EPEX Spot [MWh]	Estimated Phelix® [EUR/KWh]	Cost/day EPX Spot [TEUR]	Other Cost/day [TEUR]	Total Cost/day [TEUR]	Profit/day [TEUR]
1	Jan.	Mon.	10,959	18,168	29,127	5,825	24,959	858	4,167	0.0396	165	3,836	4,859	967
2	Jan.	Tue.	10,959	18,732	29,691	5,938	25,734	885	3,957	0.0396	157	3,836	4,877	1,061
3	Jan.	Wed.	10,959	18,768	29,727	5,945	25,784	886	3,943	0.0396	156	3,836	4,878	1,067
4	Jan.	Thu.	10,959	18,798	29,757	5,951	25,825	888	3,932	0.0396	156	3,836	4,879	1,072
5	Jan.	Fri.	10,959	18,005	28,964	5,793	24,736	850	4,228	0.0396	168	3,836	4,854	939
6	Jan.	Sat.	10,959	15,599	26,558	5,312	21,431	737	5,127	0.0396	203	3,836	4,776	536
7	Jan.	Sun.	10,959	14,381	25,340	5,068	19,756	679	5,583	0.0396	221	3,836	4,736	332
8	Jan.	Mon.	10,959	18,168	29,127	5,825	24,959	858	4,167	0.0396	165	3,836	4,859	967
9	Jan.	Tue.	10,959	18,732	29,691	5,938	25,734	885	3,957	0.0396	157	3,836	4,877	1,061
10	Jan.	Wed.	10,959	18,768	29,727	5,945	25,784	886	3,943	0.0396	156	3,836	4,878	1,067
11	Jan.	Thu.	10,959	18,798	29,757	5,951	25,825	888	3,932	0.0396	156	3,836	4,879	1,072
12	Jan.	Fri.	10,959	18,005	28,964	5,793	24,736	850	4,228	0.0396	168	3,836	4,854	939
13	Jan.	Sat.	10,959	15,599	26,558	5,312	21,431	737	5,127	0.0396	203	3,836	4,776	536
14	Jan.	Sun.	10,959	14,381	25,340	5,068	19,756	679	5,583	0.0396	221	3,836	4,736	332
15	Jan.	Mon.	10,959	18,168	29,127	5,825	24,959	858	4,167	0.0396	165	3,836	4,859	967
16	Jan.	Tue.	10,959	18,732	29,691	5,938	25,734	885	3,957	0.0396	157	3,836	4,877	1,061
17	Jan.	Wed.	10,959	18,768	29,727	5,945	25,784	886	3,943	0.0396	156	3,836	4,878	1,067
18	Jan.	Thu.	10,959	18,798	29,757	5,951	25,825	888	3,932	0.0396	156	3,836	4,879	1,072
19	Jan.	Fri.	10,959	18,005	28,964	5,793	24,736	850	4,228	0.0396	168	3,836	4,854	939
20	Jan.	Sat.	10,959	15,599	26,558	5,312	21,431	737	5,127	0.0396	203	3,836	4,776	536
...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
347	Dec.	Thu.	10,959	18,141	29,099	5,820	25,091	862	4,009	0.0396	159	3,836	4,857	963
348	Dec.	Fri.	10,959	17,376	28,335	5,667	24,033	826	4,302	0.0396	170	3,836	4,832	835
349	Dec.	Sat.	10,959	15,054	26,013	5,203	20,822	716	5,191	0.0396	206	3,836	4,757	445
350	Dec.	Sun.	10,959	13,878	24,837	4,967	19,195	660	5,642	0.0396	224	3,836	4,719	248
351	Dec.	Mon.	10,959	17,532	28,491	5,698	24,250	834	4,242	0.0396	168	3,836	4,837	861
352	Dec.	Tue.	10,959	18,077	29,036	5,807	25,003	859	4,033	0.0396	160	3,836	4,855	952
353	Dec.	Wed.	10,959	18,112	29,071	5,814	25,051	861	4,020	0.0396	159	3,836	4,856	958
354	Dec.	Thu.	10,959	18,141	29,099	5,820	25,091	862	4,009	0.0396	159	3,836	4,857	963
355	Dec.	Fri.	10,959	17,376	28,335	5,667	24,033	826	4,302	0.0396	170	3,836	4,832	835
356	Dec.	Sat.	10,959	15,054	26,013	5,203	20,822	716	5,191	0.0396	206	3,836	4,757	445
357	Dec.	Sun.	10,959	13,878	24,837	4,967	19,195	660	5,642	0.0396	224	3,836	4,719	248
358	Dec.	Mon.	10,959	17,532	28,491	5,698	24,250	834	4,242	0.0396	168	3,836	4,837	861
359	Dec.	Tue.	10,959	18,077	29,036	5,807	25,003	859	4,033	0.0396	160	3,836	4,855	952
360	Dec.	Wed.	10,959	18,112	29,071	5,814	25,051	861	4,020	0.0396	159	3,836	4,856	958
361	Dec.	Thu.	10,959	18,141	29,099	5,820	25,091	862	4,009	0.0396	159	3,836	4,857	963
362	Dec.	Fri.	10,959	17,376	28,335	5,667	24,033	826	4,302	0.0396	170	3,836	4,832	835
363	Dec.	Sat.	10,959	15,054	26,013	5,203	20,822	716	5,191	0.0396	206	3,836	4,757	445
364	Dec.	Sun.	10,959	13,878	24,837	4,967	19,195	660	5,642	0.0396	224	3,836	4,719	248
365	Dec.	Mon.	10,959	17,532	28,491	5,698	24,250	834	4,242	0.0396	168	3,836	4,837	861
Total	0	0	4,000,000	6,000,000	10,000,000	2,000,000	8,000,000	275,000	2,000,000	0.0396	79,269	1,400,000	1,754,269	245,731

Figure 19: Daily allocation of volumes and values in the fictive utility's portfolio[453]

[453] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix B - Fictive portfolio.xls", table: Portfolio_Calculation.

C. Value at Risk – Calculation

On basis of the portfolio analysed in appendix B, it is possible to estimate the VaR. Thereby, it is impractical to consider each identified risk position separately. Too many computations, time, and effort would be required. Fortunately, it is economically justifiable to simplify and aggregate many positions to handle the flood of data with adequate accuracy of the VaR estimating results.[454] As described in 3.3.2 the identified risk factors can be aggregated to two variables representing the main risks (see 3.1).

- Main risk of the sales side of the utility's portfolio is the volume risk (i) in form of a fluctuating end-customer's power demand.
- Superior risk of the procurement sides of the utility's portfolio is the price risk (j) in form of volatile wholesale spot market price for electricity.

According to the objective of this thesis, the VaR should be calculated on a daily basis (see 3.2). The confidence level is at 99% ($\alpha = 0{,}01$).

To use the variance-covariance approach illustrated as chosen method to estimate the VaR (see 3.3.2.2) referring to the assumptions mentioned above, it is necessary to extract the input factors out of the portfolio (see appendix B).

Risk factor	Invested capital [TEUR]	Revenue [TEUR]	Expected return [TEUR]	Expected rate of return	Standard variance
Households					
2 Persons	241,212	302,500	61,288	25.4%	11.4%
3 Persons	230,248	275,625	45,377	19.7%	11.6%
4 Persons	526,281	615,000	88,719	16.9%	12.3%
Industry					
Small	493,388	534,375	40,987	8.3%	15.0%
Big	263,140	272,500	9,360	3.6%	8.5%
Total	1,754,269	2,000,000	245,731	14.0%	11.7%

Figure 20: VaR calculation: Sales side of the portfolio – risk factor volume risk[455]

The invested capital reflects the total costs within the portfolio (see Figure 15, p. 82) allocated according to the customers group total estimated power demand (see Figure 14, p. 81). Figure 14 (p. 81) also provides the revenue per customer group. Expected return and rate of return are calculations based on this data. The standard variance refers to the risk factor volume risk (i). It is the standard variance of the daily changes in the fluctuating demand (see Figure 19, p. 85).

The procurement side of the portfolio refers to the price risk (j). Therefore, it concentrates on the remaining volumes that are purchased on the EPEX Spot for estimated TEUR 359,269 (see Figure 15, p. 82).

[454] Cf. Jorion (2007), p. 278.
[455] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix C – VaR.xls", table: VaR.

Risk factor	Invested capital [TEUR]	Revenue [TEUR]	Expected return [TEUR]	Expected rate of return	Standard variance
Households					
2 Persons	49,400	60,500	11,100	22.5%	11.7%
3 Persons	47,154	55,125	7,971	16.9%	11.9%
4 Persons	107,781	123,000	15,219	14.1%	12.6%
Industry					
Small	101,044	106,875	5,831	5.8%	15.4%
Big	53,890	54,500	610	1.1%	8.7%
Total	359,269	400,000	40,731	11.3%	12.0%

Figure 21: VaR calculation: Procurement side of the portfolio – risk factor price risk[456]

The revenue reflects the sale of the 2,000 GWh purchased on the spot market (see Figure 15, p. 82) allocated according to the customers group total estimated power consumption (see Figure 14, p. 81). Expected return and rate of return are again calculations. The standard variance is calculated based on the daily Phelix® baseload monthly index from 01/01/2002 to 05/28/2010 (see Figure 13, p. 80) because the estimated spot price of 0.0396 EUR/kWh (see Figure 15, p. 82) is the average electricity price of the same period (see Figure 13, p. 80).

Standard variances on the sale and on the procurement side are calculated in total. Then they are allocated to the customer groups regarding their individual sensitivity based on the fluctuating demand.

Risk factor	Share of fluctuating demand	Relative sensitivity
Households		
2 Persons	56.0%	97.4%
3 Persons	56.6%	98.4%
4 Persons	60.0%	104.3%
Industry		
Small	73.3%	127.5%
Big	41.7%	72.4%
Average	57.5%	100.0%

Figure 22: Risk sensitivity per customer group[457]

The share of fluctuating demand of their total demand expresses this sensitivity. To compare the single groups, the relative sensitivity is calculated as the deviation of the individual sensitivity from the average sensitivity. Finally, this relative sensitivity is used to allocate the standard variances.

This data provides the basis for the calculation of the VaR resulting with a daily VaR of TEUR 34,098 or about 14 % of the total value of the fictive portfolio.

[456] Source: Own calculation (2010), *local link*: “Wittenberg; Appendix C – VaR.xls“, table: VaR.
[457] Source: Own calculation (2010), *local link*: “Wittenberg; Appendix C – VaR.xls“, table: VaR.

μ_{PF} =	1 *	0.1401	+	0.2 *	0.1134	=	**0.1628**		
σ_{PF} =	$\sqrt{0.0138}$	+	0.0006	+	2 *	0.0060	=	**0.1296**	
Daily VaR at α: 0,01 =	-245,731	* (0.1628 +	-2.3263	*	0.1296)	=	**34,098 TEUR**		
						Share at the total portfolio value	*13.9%*		

Figure 23: VaR basing on the forecasted portfolio value[458]

D. Singe-Factorial Sensitivity Analysis – Calculation

The following figures show the results of the sensitivity analysis analysed in section 3.3.3 calculated with the software EXCEL 2003. Basis of the calculation is the daily average Phelix® baseload monthly index from 01/01/2002 to 12/31/2009.

Trading day	Phelix® [EUR/MWh]	Deviation - current vs. previous day	Deviation - current vs. previous day +1	Deviation: current vs. previous day +1 - logarithmical -
1	14.93			
2	21.84	46.3%	146.3%	38.0%
3	24.98	14.4%	114.4%	13.4%
4	27.29	9.2%	109.2%	8.8%
5	29.25	7.2%	107.2%	6.9%
…	…	…	…	…
2084	39.47	-3.3%	96.7%	-3.3%
2085	36.18	-8.3%	91.7%	-8.7%
2086	36.13	-0.1%	99.9%	-0.1%
2087	35.98	-0.4%	99.6%	-0.4%
2088	35.69	-0.8%	99.2%	-0.8%
Mean value	**39.56**	**0.7%**		**0.0%**
Variance	**261.09**	**1.5%**		**1.4%**
Standard variance	**16.16**	**12.2%**		**11.9%**

Figure 24: Daily average Phelix® – variance and standard variance 2002 - 2009[459]

Date	Trading day	Phelix® [EUR/MWh]	Daily changes
1-Jan-02	1	14.93	
2-Jan-02	2	21.84	46.3%
3-Jan-02	3	24.98	14.4%
4-Jan-02	4	27.29	9.2%
7-Jan-02	5	29.25	7.2%
…	…	…	…
25-Dec-09	2084	39.47	-3.3%
28-Dec-09	2085	36.18	-8.3%
29-Dec-09	2086	36.13	-0.1%
30-Dec-09	2087	35.98	-0.4%
31-Dec-09	2088	35.69	-0.8%
Standard variance 2002-2009:		**16.16**	**12.2%**
Standard variance 2005-2009:		**15.71**	**10.8%**
Standard variance 2007-2009:		**17.25**	**12.1%**
Standard variance 2009:		**7.51**	**6.5%**

Figure 25: Daily average Phelix® – standard variance of different sample periods[460]

[458] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix C – VaR", table: VaR.
[459] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix D - Singe-Factorial Sensitivity Analysis ", table: Analyses_2002-2009.
[460] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix D - Singe-Factorial Sensitivity Analysis ", table: StandVar._2002-2009.

Date	Trading day in 2010	Phelix® [EUR/MWh]	Daily changes
1-Jan-10	1	21.05	-41.0%
4-Jan-10	2	33.12	57.3%
5-Jan-10	3	35.24	6.4%
6-Jan-10	4	36.77	4.3%
7-Jan-10	5	38.74	5.4%
…	…	…	…
24-May-10	102	41.77	-3.8%
25-May-10	103	41.84	0.2%
26-May-10	104	42.11	0.6%
27-May-10	105	42.26	0.4%
28-May-10	106	42.32	0.1%
Standard variance 01-03/2010		**3.34**	**7.9%**

Figure 26: Daily average Phelix® – standard variance January - May 2010[461]

This data provide the basis for the calculation of the portfolio's risk sensitivity in part 3.3.3 (see Figure 7, p. 34) resulting with a range of potential losses from TEUR 16,080 to TEUR 30,038 depending on the chosen sample period of the sensitivity analysis.

E. Example – Using Phelix® Futures

To illustrate the effect of using power derivatives, it is supposed to be the 11/30/2009 and the utility tries to minimize the risk within its portfolio determined in appendix B. Therefore, as explained in 3.3.2, the portfolio gets confronted with the current market price[462] of that date of 35.94 EUR/MWh.[463] Assuming there are no changes in end-customer demand, the effect of the MtM calculation only reflects on the procurement side of the portfolio. Remaining volumes must be purchased on the EPEX Spot at current spot prices (see red-shaded area, Figure 5, p. 25). Hence, the portfolio return is still TEUR 2,000,000 (see Figure 14, p. 81). The procurement side changes as follows:

Arrangement	Volume [MWh]	Price [EUR/kWH]	Procure-ment cost [TEUR]	Other costs [EUR/kWh]	Total costs [TEUR]
Baseload contract	4,000,000	0.0330 *)	132,000	0.140	692,000
Peakload contract	3,000,000	0.0350 *)	105,000	0.140	525,000
Seasonal contract	1,000,000	0.0380 *)	38,000	0.140	178,000
Spot market volumes	2,000,000	0.0359 **)	71,880	0.140	351,880
Total	**10,000,000**		**346,880**		**1,746,880**

*) Contracted price as the result of bilateral negotiations with ESC
**) Spot price (average daily Phelix® Baseload index) at 11/30/2009

Figure 27: MtM at 11/30/2009 without using derivatives[464]

[461] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix D - Singe-Factorial Sensitivity Analysis ", table: StandVar._2010.
[462] Cf. Acerbi/Scandolo (2007), p 5.
[463] Cf. EEX via DataStream (access: 06/03/2010), *local link*: "Wittenberg; Appendix A - Phelix _MonthBase.xls", table: EEX-Phelix_data.
[464] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix E - MtM.xls", table: MtM.

Therefore, the portfolio's value at 11/30/2009 using MtM is TEUR 253,120 (2,000,000 – 1,746,880). It is necessary to recalculate the risk management key figures. For purposes of this thesis and according to economic practice (see 3.3.1),[465] the following analysis refers to the VaR to illustrate the risk management of a utility in the German electricity market. Starting with the portfolio value calculated above and using the VaR techniques described in 3.3.2.2 and the corresponding appendix C, a daily VaR of TEUR 33,903 or 13.4 % of the portfolio value of TEUR 253,120 is estimated.

μ_{PF} =		1 *	0.1449	+		0.2 *	0.1134	=	**0.1676**
σ_{PF} =	$\sqrt{}$	0.0138	+	0.0006	+	2 *	0.0060	=	**0.1296**
Daily VaR at α: 0,01 =		-253,120	* (0.1676 +	-2.3263	*	0.1296)		=	**33,903 TEUR**
							Share at the total portfolio value		*13.4%*

Figure 28: VaR basing on the portfolio value using MtM, without Phelix® futures[466]

Using Phelix® futures as characterised in 4.2.2.3 changes the structure of the procurement side and requires a recalculation of the portfolio value using MtM.

Arrangement	Volume [MWh]	Price [EUR/kWH]	Procure-ment cost [TEUR]	Other costs [EUR/kWh]	Total costs [TEUR]
Baseload contract	4,000,000	0.0330 *)	132,000	0.140	692,000
Peakload contract	3,000,000	0.0350 *)	105,000	0.140	525,000
Seasonal contract	1,000,000	0.0380 *)	38,000	0.140	178,000
Phelix® year future	876,000	0.0400 **)	35,040	0.140	157,680
Spot market volumes	1,124,000	0.0359 ***)	40,397	0.140	197,757
Total	**10,000,000**		**350,437**		**1,750,437**

*) Contracted price as the result of bilateral negotiations with ESC
**) Contracted price of the Phelix® baseload year future
***) Spot price (average daily Phelix® Baseload index) at 11/30/2009

Figure 29: MtM at 11/30/2009 inclusive using Phelix® baseload year futures[467]

Because of the assumed higher price of the Phelix® year future of 0.04 EUR/kWh compared with the spot price of the MtM calculation of 0.0359 EUR/kWh, the power procurement becomes more expensive. The decreased current portfolio value by TEUR 3,557 expresses thereby the costs of using this risk management instrument.

On this basis, a recalculation of the VaR is possible. Using the risk management instrument Phelix® futures is effective and reduces the VaR by TEUR 1,342 to TEUR 32,561 or 13.0 % of the portfolio value of TEUR 249,563.

[465] Cf. Harper/Keller/Pfeil (2000), p. 6; Holtdorf/Rudolf (2000), p. 122.
[466] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix C – VaR", table: VaR.
[467] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix E - MtM.xls", table: MtM.

μ_{PF} =	1 *	0.1426	+	0.11 *	0.1368	=	**0.1579**		
σ_{PF} =	$\sqrt{0.0138}$	+	0.0002	+	2 *	0.0062	=	**0.1240**	
Daily VaR at α: 0,01 =	-249,563	* (0.1579 +	-2.3263	*	0.124)	=	**32,561 TEUR**		
						Share at the total portfolio value	*13.0%*		

Figure 30: VaR basing on the portfolio value using MtM, including Phelix® futures[468]

After ordering 50 Phelix® baseload year futures at 40 EUR/MWh the current portfolio's value using MtM decreased by TEUR 3,557 to TEUR 249,563 (2,000,000 – 1,750,880).

[468] Source: Own calculation (2010), *local link*: "Wittenberg; Appendix C – VaR", table: VaR.

VI. Eidesstattliche Erklärung

Hiermit versichere ich, dass ich diese Arbeit selbstständig verfasst und keine anderen als die angegebenen Quellen und Hilfsmittel benutzt habe. Außerdem versichere ich, dass ich die allgemeinen Prinzipen wissenschaftlicher Arbeit und Veröffentlichung, wie sie in den Leitlinien guter wissenschaftlicher Praxis der Carl von Ossietzky Universität Oldenburg festgelegt sind, befolgen habe.

Oldenburg, 25.09.2010