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Risk Premiums in the German Day-Ahead Electricity Market

by

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Abstract

This paper conducts an empirical analysis of risk premiums in the German day-ahead Electricity Wholesale Market. We compare hourly price data of the European Energy Exchange (EEX) auction and of the continuous over-the-counter (OTC) market taking place prior to EEX. As OTC price data are not publicly available, data provided by the Energy Exchange Austria (EXAA) have been used as a snapshot of the OTC market. It has been found that market participants are willing to pay both, positive and negative premiums for hourly contracts that are significantly different from zero. The largest positive premiums were paid for evening peak hours on weekdays during winter months, the period of time with the highest electricity consumption levels of the year. By contrast, night hours on weekends featuring lowest demand levels display negative premiums. Hence, findings by Longstaff and Wang (2004) can be supported that power traders in liberalised markets behave like risk-averse rational economic agents.

Keywords: Electricity trading, Risk premium, EEX

JEL-classification: L94, N74, Q41

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1. Introduction

Within the last decade, the German and other European Power Markets underwent unprecedented transformations. Directives and regulations issued by the European Commission aimed to open markets, ensure non-discriminatory third-party access to power grids (Directive 2003/54/EC repealing Directive 96/92/EC) and to enforce cross border trading activities (Regulation 1228/2003) in order to harmonise prices and mitigate market power of national incumbent operators. An overview of the main regulatory issues related to European Electricity Markets and their recent progress was compiled in the "DG Competition Report on Energy Sector Inquiry" by the European Commission (2007). The report focuses on concentration, market power, vertical integration, market integration, transparency and price issues and it states that some progress has been made but many barriers to free competition still persist[1].

However, without any doubt the process of liberalisation led to an increase in power trading activities across Europe - particularly in Germany - Europe's largest economy and Power Market in terms of electricity consumption. Germany's annual power consumption amounts to 500-550 TWh. According to a recently published review of EU Wholesale Energy Markets by Rademaekers et al (2008), estimated total annual trading turnover of German power contracts grew from 2,400 TWh in 2006 to 3,200 TWh in 2007. The fact that total trading turnover in 2007 amounted to around 6 times consumption can be seen as a sign of market maturity.

Nevertheless policymakers, regulators and public opinion in Europe remain suspicious of power trading activities. This is partly due to the complexity of electricity trading and a lack of market transparency. As a result, the European Commission is currently addressing the issue to find which transparency requirements on trading activities are necessary to ensure a positive development of European Power Markets in accordance with the Directives and Regulations mentioned above (Rademaekers et al, 2008). As exchange based trading covers only a small fraction of the overall trading activities in most European countries, improved transparency in terms of market participants, traded volumes and prices of the OTC market would be beneficial for regulators and policymakers in order to asses and monitor the functioning of European Power Markets.

Within this context, this paper conducts an empirical analysis of prices and premiums paid on the German day-ahead Power Market and aims to improve transparency and understanding of this market. In order to compare day-ahead EEX auction prices with

[1] For additional interpretation of the DG competition report, see London Economics (2007) and Ockenfels (2007)

prices of the preceding continuous day-ahead OTC trading which are not publicly available yet, we decided to use price data provided by the Energy Exchange Austria (EXAA) as a snapshot of the continuous OTC market[2]. We find that positive and negative premiums for hourly contracts were paid only two hours prior to the final EEX auction. The average premium of daily delivery contracts represented by the Base block contract is slightly positive (0.61 €/MWh), but not statistically different from zero.

Premiums paid in electricity forward markets differ from those paid in markets for financial assets or storable commodities. This is due to the physical property of power – it is not storable. While the constraint of non-negativity on inventory distinguishes financial assets from storable commodities, power markets are characterised by the absence of storage capacities in meaningful quantities at competitive cost. Therefore, power prices usually feature unique properties such as price spikes and heteroscedasticity[3]. For this reason, equilibrium models for commodities as described by Fama and French (1987) or Routledge et al (2000) cannot be applied to electricity markets.

Few authors such as Bessembinder and Lemmon (2002), Benth et al (2008) or Pirrong and Jermakyan (2008) focus particularly on modeling equilibrium prices of forward contracts and risk premiums in electricity wholesale markets. Bessembinder and Lemmon (2002) present an equilibrium model that explicitly takes into account the physical properties of power and the convexity of the power production cost curve. According to their model, there are negative risk premiums for off-peak hours caused by low demand, little skewness and risk averse sellers. In peak hours however, buyers are willing to pay positive risk premiums due to the high demand and highly right skewed power prices. Benth et al (2008) also develop a model that explains the existence of negative and positive forward premiums as well. However, their work has a different focus. They incorporate the changing relative eagerness of natural buyers and sellers to hedge their positions and test their model across different forward contract maturities. They validate their model by an empirical analysis showing that contracts closer to the delivery date (e.g. one month ahead) contain positive risk premiums that increase in the presence of spike risks on the German Forward Power Market. On the other hand, hedging pressure of natural sellers leads to negative premiums for forward contracts that mature in a relatively longer period of time (e.g. six months ahead).

An empirical analysis conducted by Longstaff and Wang (2004) largely supported implications by the Bessembinder and Lemmon (2002) equilibrium model in the case of

[2] described more in depth in section 3
[3] for more details of power price properties see Weron et al (2004), Bierbrauer et al (2007) or Huisman et al (2007).

the Pennsylvania, New Jersey and Maryland (PJM) Wholesale Market. By comparing hour-ahead and day-ahead prices for each hour, Longstaff and Wang found positive premiums for hours with highest demand and negative premiums for hours with low consumption levels. Although the set of data available for the German Power Market is somewhat different, we use a similar methodology as Longstaff and Wang in this paper. Pirrong and Jermakyan (2008) also propose a model to capture risk premiums – or as they denote it, the market price of risk – for power derivatives. Their analysis also shows the presence of risk premiums at the PJM Market and the seasonality of these premiums. Other authors who recently published empirical analyses of electricity market premiums include Hadsell and Shawky (2007), Lucia and Torró (2008) and Redl et al (2009).

Most research mentioned above focuses on the relation between mid to long-term futures (e.g week ahead, month ahead or year ahead) and spot prices (usually day-ahead). Solely Longstaff and Wang (2004) and Hadsell and Shawky (2007) analyse premiums using hourly price data. This paper is the first article that presents an empirical analysis of hourly premiums in the German day-ahead Market. The timeframe between the settlement of the spot price and the forward price is less than two hours in our sample.

The body of this article is as follows. Section 2 outlines the structure of the German Power Market and focuses particularly on the German Spot Market. Section 3 describes the set of data employed for the empirical analysis of premiums paid at the day-ahead market. In section 4, tests on the significance of these risk premiums are conducted. Section 5 provides interpretations of the results obtained in the previous section and section 6 concludes.

2. The German Power Market

The following section gives a short summary of the present state of the German Power Market and focuses in particular on the Spot Market, it's most important features, market places and trading participants. Germany represents Europe's largest Power Market in terms of consumption. The four largest electricity producers RWE, E.ON, Vattenfall and ENBW hold a market share between 70 and 85 percent[4]. There are four high voltage grids operated by four transmission system operators (TSOs) which are subsidiaries of the companies mentioned above. These 380 kV grids also represent the delivery points of power that is traded between market participants and on the Power Exchanges. Congestion between and within the grids is currently tackled exclusively by redispatch of the TSOs.

[4] See Liese et al (2008) and Weight und v. Hirschhausen (2008)

Other practices such as market splitting or nodal pricing[5] are not yet in focus. This decrease in economic efficiency is accepted in order to benefit from one single, sufficiently large and actively traded market area. Today, the German Power Market is interconnected with a number of other European Power Markets of differing liquidity. Interaction between those markets requires transmission rights. Daily explicit day-ahead auctions are in place for interconnector transmission capacities to and from Poland, Czech Republic, Switzerland, France, Netherlands, Denmark and Sweden. Most of these countries also feature liquid exchange-based day-ahead trading, some have actively traded OTC markets. Market coupling and implicit auctioning of interconnector capacities between the German Market and the Nordpool[6] region, namely Sweden and Denmark, should be established during 2009.

The two main market places for day-ahead trading in Germany are represented by the exchange EEX and electronic OTC trading platforms. Due to its high liquidity, EEX is widely regarded as the benchmark and reference point of the German day-ahead Power Market. The annual day-ahead volume increased from 88.7 TWh in 2006 to 127.3 TWh in 2007 and 154.5 TWh in 2008. Accordingly, daily spot trading volumes amounted to more than one quarter of the overall German energy demand in 2008. Like other Energy Exchanges in Europe, EEX facilitates a day-ahead market by the means of a uniform pricing auction[7]. On the day prior to delivery, price dependent and price independent hourly bids and offers can be submitted to the electronic EEX platform latest 12 p.m. Additionally, offers for individual power blocks consisting of at least two hours with the same quantity and price can be submitted. Prior to 12.15 p.m. and in accordance with the principle of the most executable volume, EEX clears all bids and offers and publishes hourly market clearing prices and volumes at 12.15 p.m. In contrast to Electricity Pool Systems like the PJM Market it is not mandatory for energy consumers, producers and traders to participate in auctions at the exchange based system EEX. Liquidity on the Intraday Market which covers the period between the EEX day-ahead auction and the actual delivery period on the next day is only fractional compared to EEX and thus currently not suitable to conduct further research. Real time imbalances in the power system are balanced by generation units which can provide positive or negative primary, secondary and tertiary reserve energy. TSOs procure reserve energy on separate markets[8].

In contrast to exchanged based trading, OTC trades take places directly between the counterparties and are often facilitated by broker companies. Transactions are executed via

[5] See Brunekreeft et al (2005) for concepts of market splitting and nodal pricing
[6] Energy Exchange for the Scandinavian region
[7] See Ockenfels et al (2008) for more EEX auction details.
[8] For more details see Swider and Weber (2003)

electronic broker platforms or bilaterally via telephone. Only standardised block contracts such as Base (delivery period h1-h24), Peak (h9-h20), Off-Peak (h1-h8, h21-h24), Night (h1-h6) and several others can be traded. Most day-ahead trading activities take place between 8 a.m. and 12 p.m. on the day prior to the delivery day. Thus, the continuous OTC market is important for market players to hedge larger volumes prior to the exchanged based auction at 12 p.m. The OTC-market can be considered to be the last forward market before the final EEX exchange clears. Although trades conducted on the electronic platforms can be seen by all market participants who have access to these platforms, there is to our knowledge no public register that publishes information about trading participants, trade prices or traded volumes on the OTC market. This certainly adds to the often criticised lack of transparency of OTC trading activities in comparison to exchange based trading. Therefore, the volumes traded on the day-ahead OTC market are difficult to quantify. However, the questioning of several market participants revealed that – in terms of volumes traded – exchange based and OTC based day ahead trading are in the same order of magnitude.

A brief comparison between day-ahead EEX auction and day-ahead OTC prices for Base block contracts was published within the Energy Sector Inquiry by the European Union (2007). The report states that *"As a result of continuous arbitrage, prices of identical products traded on different marketplaces (i.e. on power exchanges or OTC markets) develop in parallel. Indeed […], prices for day-ahead baseload delivery observed on the EEX […] and the German OTC market are very closely correlated both in terms of development and levels"*. This conclusion is imprecise, particularly in relation to the day-ahead Power Market. Firstly, continuous arbitrage is not possible as continuous OTC trading takes place in the morning hours before the EEX auction. Hence, there is a time gap between the two marketplaces. Secondly, since no data source is quoted it is not specified which type of price is meant by OTC price. Since OTC-trading is continuous, there is not one single price that could be used as a reference OTC price. More information regarding traded volumes, prices and a comprehensive overview was compiled by Rademaekers et al (2008) on behalf of the European Commission.

There is a whole range of trading participants in the European and German Power Markets who can be broadly divided into generators and retailers with inherent physical long or short positions and pure traders and banks who typically aim to exploit prices differences and take speculative positions. However, the Energy Sector Inquiry by the European Commission (2007) states that large power producers are also engaged in speculative and arbitrage trading. Smaller producers and retailers on the other hand trade mainly to optimise their portfolios. Additionally, it is important to note that natural buyers do not necessarily buy and natural sellers do not necessarily sell on the day-ahead power market. Depending on their long-term procurement, hedging strategies and short term demand and supply variations, retailers might sell excess power and producers might repurchase power that was sold on future or forward markets in order to optimise their portfolios. Therefore, it is very likely that over time most market participants will appear on both sides of the market.

In early 2009, more than 150 participants from 18 European countries and the U.S. were registered to trade on the EEX day-ahead Power Market. They include all the major power utilities of Central Europe, transmission system operators, local energy companies and municipalities as well as pure energy trading companies, several banks and others. Small companies which do not have direct access to the EEX trading system can trade via separate accounts of other trading members. To our knowledge there are no sources stating how many of these trading participants are also active on the OTC market. However, due to the function of the OTC market to hedge positions before the EEX auction, we assume that most participants with considerable volumes are engaged in the OTC market as well. At the Energy Exchange Austria (EXAA), which we use as a snapshot of the OTC market[9], about 50 participants from 13 countries were registered. Although this number seems to be small in comparison to EEX, all major energy utilities of Central Europe as well as several banks and pure energy trading companies are trading members at EXAA.

3. Data

In order to facilitate a comparison of hourly EEX prices and OTC prices which are not publicly available, we decided to use prices provided by EXAA as a snapshot of the OTC market. EXAA is an Austrian based power exchange which conducts an hourly day-ahead auction between 10.12 a.m. and 10.15 a.m. for German (E.ON and RWE) and Austrian (APG) delivery points. As there have been no congestions reported so far, prices at these delivery points were always identical on EXAA for the Austrian and German market areas. Additionally, it is crucial to mention that EXAA prices coincide with continuous OTC prices at the time of the auction, otherwise arbitrage between the two market places was possible. Hence, EXAA publicly provides a set of data that reflects the OTC market approximately 2 hours prior to the final EEX auction. The data sets we use consist of hourly day-ahead data publicly provided by the EEX and EXAA on their internet platforms. They cover the period from October 1, 2005[10] to September 30, 2008.

[9] See section 3 for more details

[10] The start date October 1, 2005 was chosen due to illiquid trading on EXAA in the first half of 2005 resulting in missing price data.

Accordingly, we work with a data set of 1096 days including a price for each of the 24 hours for each delivery day. Prices are cleared on the day prior to the delivery day at 10.15 a.m. on EXAA and 12.15 p.m. on EEX. As there has been no trading on the weekends during the time period covered by our data, prices for delivery day Sunday and Monday were fixed on Fridays. The same principle holds for public holidays.

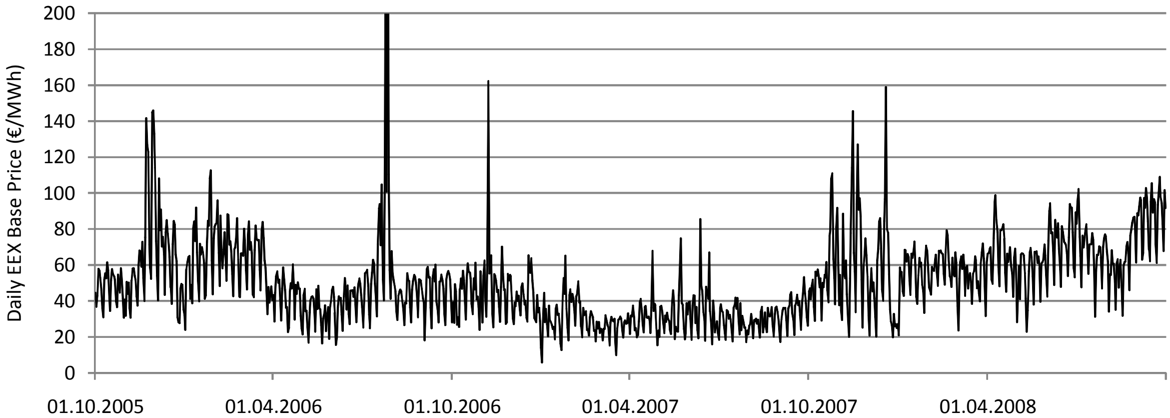

Figure 1: Daily EEX Base Price. Data used with permission from EEX.

The average daily EEX price also known as Base contract is shown in Figure 1. The figure reveals two of the most apparent features of power prices: high volatility and price spikes. Table 1 and Table 2 list the hourly summary statistics for the EEX and EXAA respectively. Next to the mean, minimum, median and maximum price, the volatility and skewness for each hour is listed. The term h1 corresponds to the delivery period from 0-1 a.m. and so on. Additionally, the tables list summary statistics for five selected and frequently traded block products. A block product price consists of the average price of all hours it contains. All prices are quoted in €/MWh. Table 1 reveals several basic features of the German Power Market. Firstly, mean prices in general follow the power demand curve. During night hours from h1-h6, power demand is at its lowest levels[11] with average prices at a range between 25 and 37 €/MWh. During the peak hours h9-h20 on the other hand, prices are on average more than twice as high. These higher prices are due to the fact that gas and oil fueled power stations produce at the margin most of the peak hours. These plants have higher variable generation costs than nuclear, lignite or coal fired power stations which generally produce at the margin during off-peak hours in the German system[12].

All hourly maximum power prices for h10-h16 in table 1 originate from only two days in July 2006, a time when persistent high temperatures across Central Europe led to high power demand. Additionally, high river temperatures led to cooling water restrictions and

[11] Compare to Figure 2
[12] A detailed analysis of the German power plant structure is given by Borchert et al (2006).

reduced power output for a large number of power plants. The highest hourly maximum prices amounted to 2000.07 €/MWh for h12 on July 25, 2006 and 2436.63 €/MWh for h19 on November 11, 2006. Throughout this paper, we add alternative calculations excluding these two extreme price spikes, listed as 12a and 19a in table 1. The minimum price of several night and morning hours within the timeframe observed was zero. Even if there was more supply than demand at a price of zero, power prices could not turn negative on EEX as the minimum price is set to be zero. Instead, the principle of pro rata assignment was adopted to match all bids and offers. Pro rata assignment refers to a proportionate execution of the offers at any given hour with supply surplus.

Table 1
Summary Statistics for Hourly and Block Day-Ahead EEX*-Prices

Hour	Mean	Min	Median	Max	Standard d.	Skewness
h1	36.89	1.64	34.28	76.02	14.11	0.52
h2	32.03	0.00	29.95	71.07	13.46	0.45
h3	28.65	0.00	27.12	67.93	12.88	0.39
h4	25.73	0.00	23.98	69.52	12.55	0.39
h5	26.06	0.00	24.05	69.92	12.43	0.38
h6	31.61	0.00	30.29	70.28	13.82	0.23
h7	36.63	0.00	34.80	94.51	19.89	0.18
h8	53.11	0.00	51.14	301.01	30.72	1.25
h9	59.44	0.00	55.70	437.26	33.45	2.34
h10	64.60	0.00	59.84	499.68	36.47	3.16
h11	68.54	0.00	62.68	998.24	44.65	9.08
h12	77.05	5.56	68.01	2000.07	81.64	16.12
h12a**	75.29	5.56	68.00	1399.99	57.33	12.22
h13	67.08	6.96	63.03	699.81	37.94	6.44
h14	63.57	2.65	59.17	699.88	37.12	6.30
h15	59.98	0.07	55.04	800.09	37.83	7.75
h16	56.04	0.12	51.56	693.23	34.21	6.79
h17	54.70	3.86	50.14	300.01	29.60	2.27
h18	61.84	6.90	54.07	821.90	49.03	7.10
h19	67.54	15.95	59.11	2436.63	86.50	19.85
h19a***	65.38	15.95	59.07	701.01	48.52	6.38
h20	60.00	17.97	57.06	250.04	27.75	1.78
h21	55.21	15.07	53.23	125.02	21.43	0.49
h22	48.61	13.48	46.31	105.93	17.92	0.49
h23	46.93	14.65	44.25	94.82	16.58	0.47
h24	38.23	1.61	35.28	80.98	14.22	0.58

Block period	Mean	Min	Median	Max	Standard d.	Skewness
h1-h24, Base	50.84	5.80	47.04	301.54	23.84	2.19
h9-h20, Peak	63.37	6.76	58.05	543.72	35.75	4.03
h1-h8, h21-h24****	38.32	4.85	36.95	83.19	14.85	0.47
h1-h6, Night	30.16	0.27	28.25	69.72	12.66	0.44
h17-h20, Noon	61.02	15.24	54.60	674.76	39.99	5.91

* Data used with permission from EEX, European Energy Exchange.
** excludes data from July 25th, 2006 (EEX h12: 2000.07 €/MWh)
*** excludes data from November 7th, 2006 (EEX h19: 2436.63 €/MWh)
**** Off-Peak

Next to mean prices, also standard deviation and skewness of power prices are low during off-peak hours (h1 – h8 and h21 – h24) compared to peak hours. The most volatile hours in our data set are summer peak (h9 to h16) and winter peak hours (h18, h19). They exhibit standard deviations between 33.5 and 81.6 €/MWh. Standard deviations of h12 and h19 even exceed the average prices of these hours. Not surprisingly, their distribution is also highly right-skewed. Skewness ranges from 2.3 to 19.9 €/MWh. Off-peak hours on the other side display skewness of less than 0.6 €/MWh except of the ramping hour h8. Positive skewness of power spot prices is attributable to the convex shape of the power supply curve and to the fact that power is non-storable. This phenomenon is a basic feature of power markets and was described by several authors, including for the German Power Market by Borchert et al (2006).

However, seasonal changes in price patterns are not observable from table 1. While the highest prices during summertime are paid in h11-h13, prices peak in h18 and h19 during winter months. This originates from changing power demand patterns during the seasons as plotted in Figure 2. Demand peaks at noon during summer and in h18 and h19 during winter season, with absolute winter peak demand levels significantly higher than summer peaks. According to data provided by UCTE (2008), the 10 hours with the highest demand within the time period of our dataset can be found either in November or December, while lowest demand was measured in May and June. Additionally, weekly price patterns featuring lower prices on weekends and price changes caused by varying fuel prices are not apparent from Table 1.

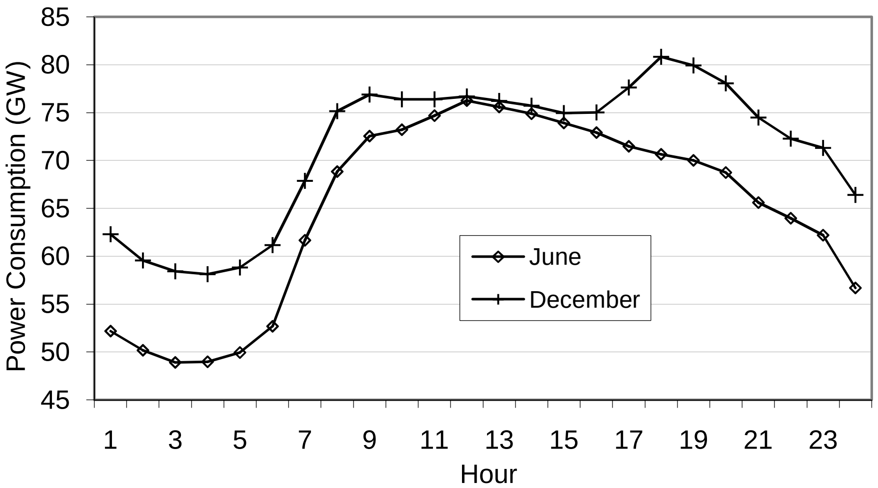

Figure 2: Power consumption in Germany on the third Wednesday in June and December 2007. Data provided by UCTE (2008)

Table 2 lists the summary statistics of EXAA prices, representing the continuous OTC market approximately 2 hours prior to the final exchange EEX. Regarding price shape, intraday variation and magnitude of mean prices, EXAA and EEX show very similar properties. However, standard variation, skewness and maximum prices display some remarkable differences. Standard variation is higher on EEX in all peak hours except of h20. Skewness is also higher on EEX for all peak hours. Additionally, maximum prices during the peak hours are uniformly lower on EXAA except of h20. The highest EXAA prices within the time period covered by our data were 888.00 €/MWh in comparison to 2000.07 €/MWh on EEX in h12 and 519.93 €/MWh in comparison to 2436.63 €/MWh in h19.

These differences support the thesis that power prices are more volatile and display more extreme variations at EEX, which – except for the illiquid intraday trading market – is considered to be the last opportunity for traders to close positions. EXAA and the OTC market, on the other hand, can be considered to be the last forward markets prior to EEX and thus they are less volatile and show less extreme variations. A dataset of the PJM Market comparing day-ahead and hour-ahead prices used by Longstaff and Wang (2004) displays very similar properties.

Table 2
Summary Statistics for Hourly Day-Ahead EXAA*-Prices

Hour	Mean	Min	Median	Max	Standard d.	Skewness
h1	36.97	6.83	35.00	81.00	13.38	0.51
h2	31.64	0.55	29.81	68.53	12.46	0.54
h3	28.17	0.01	26.40	65.64	11.84	0.53
h4	25.57	0.01	23.59	75.00	11.49	0.63
h5	26.00	0.01	24.15	62.50	11.56	0.53
h6	31.19	0.01	30.21	70.30	13.24	0.27
h7	37.14	0.01	36.58	92.06	18.62	0.21
h8	53.92	0.01	51.14	208.21	29.03	0.80
h9	59.81	0.01	57.53	205.00	29.52	0.82
h10	65.18	11.00	61.67	376.93	33.25	2.21
h11	69.26	11.67	65.00	459.46	35.88	2.82
h12	76.28	0.07	69.85	888.00	49.48	6.94
h13	67.63	20.60	63.97	458.89	33.86	3.78
h14	63.99	17.00	60.95	409.65	31.87	2.75
h15	60.16	3.51	57.07	350.00	30.85	2.41
h16	57.02	11.27	54.05	300.00	28.87	1.88
h17	56.65	9.83	52.06	240.00	28.97	1.49
h18	65.36	12.68	55.59	517.55	47.92	4.09
h19	68.31	17.60	60.00	519.93	46.63	3.87
h20	61.87	20.00	59.00	302.37	28.95	1.72
h21	55.78	19.40	54.94	127.78	20.69	0.49
h22	49.15	9.99	47.00	100.57	17.02	0.44
h23	48.10	1.00	45.73	90.00	16.47	0.36
h24	39.48	1.00	37.71	84.27	14.28	0.48

Block period	Mean	Min	Median	Max	Standard d.	Skewness
h1-h24, Base	51.44	13.60	48.40	177.85	22.32	1.15
h9-h20, Peak	64.29	17.26	60.25	299.99	32.03	1.89
h1-h8, h21-h24**	38.59	8.14	37.18	80.50	14.46	0.46
h1-h6, Night	29.92	1.40	28.25	66.25	11.95	0.50
h17-h20, Noon	63.05	16.52	56.52	370.41	36.47	2.81

* Data used with permission from EXAA, Energy Exchange Austria.
**Off-Peak

4. Risk Premiums

As mentioned in section 1, standard cost-of-carry approaches cannot be applied to determine forward premiums in electricity markets due to the fact that power is non-storable in meaningful quantities at competitive cost. Hence, in equilibrium models the *"forward premium represents the equilibrium compensation for bearing the price and/or demand risk for the underlying commodity. […]. Forward premia should be fundamentally related to economic risk and the willingness of different market participants to bear these risks."* (Longstaff and Wang, 2004). We define the risk premium[13] $RP_{i,t}$ as the difference between the expected spot price and the forward price for each hour i.

$$RP_{i,t} = F_{i,t} - E_t\left[S_{i,t+1}\right] \tag{1}$$

where $F_{i,t}$ is the forward price and $E_t[S_{i,t+t}]$ the conditional expectation of the spot price. The expectation is conditional to all information available at time t. Analysing realised risk premiums rather than modelling expected spot prices requires some additional assumptions. We denote the difference between the expected and the realised spot price as forecast error which can also be written as random noise $\varepsilon_{i,t+t}$ (equation 2). In the course of this paper, we assume that the forecast error $\varepsilon_{i,t+t}$ has a mean of zero and is independent of information available at time *t*.

$$\varepsilon_{i,t+1} = E_t\left[S_{i,t+1}\right] - S_{i,t+1} \tag{2}$$

We define EEX as the spot market and EXAA reflecting the OTC market before the EEX as forward market using the data presented in the previous section. Hence, the timeframe between *t* and *t+1* is only two hours. Thus, RP_i is on average positive if the price at the forward market EXAA is higher than at the spot market EEX and vice versa.

$$RP_i = \frac{1}{T}\sum_{t=1}^{T} EXAA_{i,t} - EEX_{i,t+1} \tag{3}$$

Risk premiums of block contracts are computed in the same way. We use t-statistics to ascertain not only whether the premiums observed are positive or negative, but also to test whether the null-hypothesis that RP_i is zero can be rejected or not. Autocorrelation and heteroscedasticity consistent estimates of the variances were used for all t-statistics.

[13] As both terms forward premium and risk premium are used in literature to describe the same concept, we use these terms interchangeable.

Table 3 and Figure 3 summarise the mean hourly risk premiums paid in the German day-ahead Power Market for all 1096 days of the dataset. The overall mean of the premium represented by the Base block contract is positive (0.61 €/MWh), but not statistically different from zero. However, premiums observed are statistically significant at the 5 percent level for 5 of the 24 hourly contracts. Significant positive premiums can be observed exclusively for evening hours. Three of the four hours with the highest demand levels in winter h17-h20[14] were traded with positive premiums that are significantly different from zero at the 5 percent level. The highest premium were paid in h18 (3.52 €/MWh) and h17 (1.95 €/MWh), In terms of the average EEX price in h18, the premium accounts for a percentage premium of 5.9 percent. Additionally, the frequently traded block h17-h20 displays a positive premium of 2.03 €/MWh, statistically significant at the 10 percent level.

Table 3
Tests for the Presence of Risk Premiums in the German Power Spot Market

	All Days			Weedays			Weekends		
Hour	**Mean**	**t-statistic**	**p-value**	**Mean**	**t-statistic**	**p-value**	**Mean**	**t-statistic**	**p-value**
h1	0.08	0.28	0.780	0.42	1.24	0.214	-0.74	-1.47	0.143
h2	-0.39	-1.36	0.174	-0.13	-0.50	0.617	-1.04	-1.74	0.083
h3	-0.48	-1.49	0.136	-0.09	-0.30	0.763	-1.46	-2.41	0.017
h4	-0.16	-0.39	0.698	0.37	0.79	0.427	-1.49	-2.18	0.030
h5	-0.07	-0.19	0.853	0.32	0.84	0.401	-1.02	-1.60	0.110
h6	-0.42	-1.15	0.253	-0.21	-0.58	0.564	-0.94	-1.48	0.139
h7	0.52	1.04	0.300	0.09	0.15	0.879	1.58	1.73	0.084
h8	0.81	0.88	0.378	0.24	0.21	0.832	2.22	3.04	0.003
h9	0.36	0.41	0.679	0.17	0.15	0.881	0.86	1.51	0.133
h10	0.58	0.60	0.546	0.61	0.53	0.593	0.50	0.73	0.467
h11	0.72	0.67	0.502	0.81	0.53	0.597	0.50	0.68	0.494
h12	-0.77	-0.22	0.829	-1.27	-0.26	0.797	0.47	0.54	0.589
h12a*	0.72	0.85	0.409	0.82	0.73	0.468			
h13	0.55	0.56	0.573	0.83	0.62	0.537	-0.16	-0.26	0.798
h14	0.42	0.42	0.675	0.35	0.26	0.793	0.59	0.99	0.321
h15	0.17	0.15	0.885	0.00	0.00	0.998	0.62	1.47	0.142
h16	0.97	0.97	0.332	0.93	0.71	0.481	1.07	2.07	0.039
h17	1.95	1.98	0.048	2.29	1.66	0.097	1.10	1.98	0.049
h18	3.52	2.61	0.009	4.49	2.15	0.032	1.10	1.17	0.242
h19	0.77	0.18	0.858	0.90	0.15	0.877	0.46	0.55	0.586
h19a**	2.88	1.55	0.122	3.86	1.25	0.212			
h20	1.87	3.26	0.001	2.68	3.79	0.000	-0.14	-0.18	0.861
h21	0.58	1.15	0.249	0.32	0.60	0.549	1.20	1.42	0.158
h22	0.53	1.14	0.255	0.42	0.84	0.401	0.82	1.21	0.227
h23	1.17	2.14	0.033	1.29	2.58	0.010	0.86	1.12	0.262
h24	1.25	2.59	0.010	1.27	2.63	0.001	1.21	1.70	0.091
Block period	**Mean**	**t-statistic**	**p-value**	**Mean**	**t-statistic**	**p-value**	**Mean**	**t-statistic**	**p-value**
h1-h24, Base	0.61	1.27	0.203	0.71	1.41	0.254	0.34	1.30	0.164
h9-h20, Peak	0.93	1.12	0.263	1.07	0.96	0.337	0.58	1.23	0.220
h1-h8, h21-h24***	0.27	1.04	0.297	0.36	1.26	0.210	0.06	0.22	0.829
h1-h6, Night	-0.24	-0.92	0.359	0.11	0.44	0.662	-1.11	-2.31	0.022
h17-h20, Evening	2.03	1.75	0.080	2.59	1.55	0.122	0.63	1.04	0.299

t-statistics are based on autocorrelation and heteroskedasticity consistent estimates of the variances
* excludes data from July 25th, 2006 (EEX: 2000.07 €/MWh, EXAA: 364.92 €/MWh)
** excludes data from November 7th, 2006 (EEX: 2436.63 €/MWh, EXAA: 126.48 €/MWh)
*** Off-Peak

[14] compare to figure 2

Additionally, we analyse subsets of the data in order to obtain a more detailed pattern of time and seasonal variations of the risk premiums observed. As shown in table 3, the subsets "weekdays" (782 sample days) and "weekend days" (314 sample days) are drawn from the overall sample. Their comparison reveals some remarkable differences. First, positive risk premiums for the evening peak hours are much smaller on weekend days. By contrast, the same hours during weekdays display risk premiums that are significantly different from zero. The highest positive premiums were paid in h18 (4.49 €/MWh) and h20 (2.68 €/MWh). In terms of the average EEX prices on weekdays, the positive premium paid on EXAA accounts for a percentage premium of 6.4 percent in h18 and 4.1 percent in h20. The comparison of the night hours h1-h6 uncovers additional information about varying premiums. While risk premiums are close to zero and not statistically significant on weekdays, they are negative on weekend days. Risk premiums are negative at a 10 percent confidence level for three of the six night hours. The highest negative premiums were paid in h3 (-1.46 €/MWh) and h4 (-1.49 €/MWh). In terms of the average EEX prices on weekend days, the negative premium accounts for a percentage premium of -5.2 percent in h3 and -6.0 percent for h4. Also the frequently traded night block h1-h6 displays a negative premium (-1.11 €/MWh) on weekend days, statistically significant at the 5 percent level.

Table 4
Tests for Time Variation of Risk Premiums during Winter and Summer

	All Days			Weedays			Weekends		
Hour	**Mean**	**t-statistic**	**p-value**	**Mean**	**t-statistic**	**p-value**	**Mean**	**t-statistic**	**p-value**
h17 May - Aug	-0.15	-0.07	0.942						
h18 May - Aug	0.65	1.04	0.301						
h19 May - Aug	0.47	0.85	0.394						
h20 May - Aug	0.95	1.58	0.114						
h17 Nov - Feb	4.66	2.80	0.005	5.83	2.51	0.013	1.69	1.27	0.208
h18 Nov - Feb	7.46	1.48	0.141	9.96	1.83	0.069	1.12	0.56	0.580
h19 Nov - Feb	0.11	0.01	0.004	-0.20	-0.01	0.991	0.88	0.60	0.553
h19a* Nov - Feb	6.52	1.26	0.208	8.75	1.08	0.280			
h20 Nov - Feb	4.27	3.23	0.001	5.68	3.96	0.000	0.69	0.39	0.696

t-statistics are based on autocorrelation and heteroskedasticity consistent estimates of the variances
* excludes data from November 7th, 2006 (EEX: 2436.63 €/MWh, EXAA: 126.48 €/MWh)

Next, the dataset was further divided into summer and winter month in order to look for seasonal variations of the risk premiums. We define May to August as summer (369 sample days) and November to February as winter month (361 sample days). As shown in table 4, we focus on the evening peak hours that displayed positive risk premiums in the overall sample. Additionally, h17-h20 represent the hours with highest power demand in the winter season, whereas the same hours are not as crucial during summer months[15]. Comparing all summer and all winter days reveals clear differences in the premiums paid. The average risk premium of the four hours is more than eight times higher during winter

[15] Compare to Figure 2

months in comparison to summer months. Premiums in summer month are all smaller than 1 €/MWh and none is statistically significant. Interestingly though, merely the risk premiums for h17 (4.66 €/MWh) and h20 (4.27 €/MWh) are statistically significant at a 5 percent level during winter time. Although h18 and h19a display even larger mean premiums, they are not significant due to their large autocorrelation and heteroscedasticity consistent estimated volatilities. As shown in table 4, this changes if one further divides the winter days into weekdays (259 sample days) and weekend days (102 sample days). Again, risk premiums are higher on weekdays than on weekend days. Additionally, premiums are statistically significant at a 10 percent level for three of the four hours on weekdays, but for none of the hours on weekend days. Apart from h19a, the highest premiums were paid in h17 (5.83 €/MWh) and h18 (9.96 €/MWh) during the winter period. In terms of the average EEX prices for h17 and h18 on winter weekdays, these premiums account for percentage premiums of 8.1 and 10.2 percent, respectively.

5. Interpretation

The results obtained in section 4 are consistent with the equilibrium model for power markets developed by Bessembinder and Lemmon (2002) and the empirical analysis of PJM market prices undertaken by Longstaff and Wang (2004). The model developed by Bessembinder and Lemmon associates the variance and skewness of the underlying power prices to the premiums paid in the forward market. As mentioned above, the convex power supply curve leads to right skewed power prices, particularly in peak hours with the highest demand. Thus, buyers face the risk of considerable losses if they need to cover a short position during the presence of positive spikes. The fact that the prices of two hours during the timeframe observed were above 2000 €/MWh clearly demonstrates that the risk of price spikes is real. In a similar fashion to Benth et al (2008) one can use the term “sellers market” to explain the presence of positive risk premiums for hours with the highest demand. Our data confirm that power traders are willing to pay large premiums of up to 10 percent for the evening peak hours h17-h20 on weekdays during winter months. These hours feature the highest demand levels of the year and price spikes often occur. However, traders are not willing to pay risk premiums for the same hours on weekends or during summer season when demand is much lower. Seasonality of risk premiums was also shown by Pirrong and Jermakyan (2008) and Lucia and Torró (2008). According to Pirrong and Jermakyan (2008), forward premiums on the PJM Market peaked for daily deliveries in July and August which feature the highest consumption levels of the year. On the other side, they found that forward prices are downward biased in shoulder months with relatively low demand. Lucia and Torró (2008) found time-varying risk premiums for the Nordpool region. Premiums were largest during autumn and winter, the time with highest demand and lowest hydro reservoir levels in Scandinavia.

The data confirm that power traders behave risk-aversely and rationally and are willing to pay significant risk premiums in the presence of risk factors. This is rational, as the right skewness of power prices can lead to substantial losses for those who hold short power forward positions. Pirrong and Jermakyan (2008) denote this as left skewness of the profit distribution for those who are short. They describe the case of a large utility in the U.S. whose entire year's earnings were wiped out on one single day due to a short position. Cases of corporate default and near bankruptcy due to power price spikes were also reported by Bessembinder and Lemmon (2002). Hence, it is well understood that there is a demand for risk reduction and companies profit from reducing risk of their cash flows and variability of returns by hedging their positions.

On the other side, there is only little skewness during off-peak hours, particularly from h1 to h6 when demand is at its lowest level. Hence, Bessembinder and Lemmon argue that sellers who want to hedge their revenues induce a downward bias in equilibrium forward prices. The absence of buying interest during hours of lowest consumption leads to a "buyers market" with negative risk premiums. Our findings confirm this theory. Statistically significant negative premiums of up to -6 percent were paid for several night hours and the night block h1-h6 on weekend days. These periods of time coincide with the lowest load levels of each week.

However, it is not feasible to compare the order of magnitude of the premiums observed in the German and the PJM Market. This is due to the different type of data sets that were used. While we compare two different types of hourly day-ahead prices, Longstaff and Wang (2004) use a set of day-ahead and hour-ahead data. Nevertheless, positive as well as negative risk premiums for some individual hours seem to be large in comparison to other studies as the timeframe between the forward and the spot market is less than two hours. As shown by Bessembinder and Lemmon (2002) and Hadsell and Shawky (2007), the existence of large premiums could be an indication that the German Power Spot Market is not yet fully integrated into the wider financial market, despite the fact that several pure trading companies and investment banks are active in it.

6. Conclusion and Discussion

This paper presents an empirical analysis of risk premiums paid in the German day-ahead Power Market. The overall mean of the risk premium is positive (0.61 €/MWh), but not statistically different from zero. However, we find negative as well as positive risk premiums that are significantly different from zero for hourly delivery contracts. The largest positive premium of on average 9.96 €/MWh (10.2 percent) was paid for the evening peak hour h18 on weekdays during winter, the time with the highest power consumption levels of the year. Our results are consistent with equilibrium forward pricing models and empirical results by Lemmon and Bessembinder (2002), Longstaff and Wang (2004) and Pirrong and Jermakyan (2008) for the PJM Market and confirm that energy traders behave rationally like risk averse-agents. Their willingness to pay positive risk premiums is directly related to the presence of price spikes in spot power markets which can lead to substantial losses to those who hold physical short positions that need to be covered.

Negative premiums of up to -1.49 €/MWh (-6.0 percent) were paid for night hours on weekends, the time with lowest energy demand levels. This is also consistent with Bessembinder and Lemmon (2002) who argue that hedging pressure of producers in off-peak hours can lead to a downward bias of forward prices. It remains to be seen how the introduction of negative prices will affect negative risk premiums of weekend night hours in the future. From September 2008 EEX reduced the price floor, negative prices of up to -3,000 €/MWh are now possible. Negative prices might result in a left-skewed price distribution and larger negative premiums for the hours affected. In December 2008, the day-ahead EEX price was less than -100 €/MWh for three consecutive hours.

Our dataset covers a period of only three years which does not allow for an analysis of how the entrance of new market participants affected the market. Hence, we are not looking into whether systematic changes in risk premiums have occurred over time. As trading volumes increased and neutral pure trading companies and banks started in the power trading businesses during recent years, one would expect risk premiums to decrease over time[16].

We explicitly do not analyse whether risk premiums are paid on the EEX day-ahead Market in comparison to the Intraday Market which covers the time frame between the day-ahead auction and the actual delivery period. This could be an interesting subject for further research as soon as market liquidity improves and data problems are solved. Unlike Daskalakis and Markellos (2009), we argue that the EEX intraday data are not of satisfactory quality to conduct further research on risk premiums for several reasons. First, since intraday trading has started in September 2006, there have been no intraday trades reported in 45 percent of the hours in 2006, 19 percent of all hours in 2007 and 3 percent of all hours in 2008 resulting in missing price data. Secondly, the estimated figure of hours

[16] See Bessembinder and Lemmon (2002) and Hadsell and Shawky (2007)

with only one trade is in the same order of magnitude in each year[17]. Additionally, it is hardly feasible to compare the prices of the EEX day-ahead Auction with prices of the continuous EEX Intraday Market. EEX publishes the minimum, maximum, average and last intraday price of each hour. As it is not know at what specific time intraday trades take place and the trading period can be longer than 24 hours, the determination and comparison of risk premiums between the day-ahead auction and the continuous intraday market is not consistent.

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[17] Estimated percentage of intraday hours with only one trade: 20 percent in 2006, 17 percent in 2007 and 6 percent in 2008

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