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A High-Frequency Empirical Analysis

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ABSTRACT

We conduct an empirical analysis of electricity forward prices using a high-frequency data set of hourly spot and day-ahead forward prices. We find that there are significant risk premia in electricity forward prices. These premia vary systematically throughout the day and are directly related to economic risk factors such as the volatility of unexpected changes in prices and demand as well as the risk of price spikes. In contrast to the popular post-Enron view that electricity markets are easily manipulated, these results support the hypothesis that electricity forward prices are determined rationally by risk-averse economic agents.

1. INTRODUCTION

The issue of how electricity is priced in spot and forward wholesale power markets has become one of the most controversial topics facing utilities, power producers, regulators, political officials, accounting firms, and a broad array of financial market participants. Although the spotlight initially focused on Enron, recent allegations of questionable electricity trading practices at CMS Energy, Dynegy, Reliant Resources, and other major energy firms have raised questions about whether electricity prices reflect economic fundamentals or are manipulated by the actions of large traders gaming the wholesale market.[1] An important complication that makes this issue particularly difficult to address is the unique nature of electricity as a commodity since it is virtually nonstorable. This feature eliminates the buffering effect associated with holding inventories, and makes the possibility of sudden large price changes more likely.

In an effort to shed light on these and related issues, this paper examines the pricing of electricity forward contracts in the day-ahead electricity market. These types of derivative contracts are rapidly growing in importance as both financial risk management tools for hedgers as well as liquid investment vehicles for energy trading firms. Since electricity is not storable, the standard no-arbitrage approach to modeling forward prices cannot be applied. Accordingly, we focus on the question of how electricity forward prices are related to expected spot prices. Economic theory suggests that the forward premium (the relation between the forward and expected spot prices) should represent compensation to financial market participants for bearing risk. Finding evidence that premia in electricity forward prices are related to measures of risks faced by market participants would support the view that prices reflect economic fundamentals and also provide insight into the determinants of energy derivative prices.

The data for this study consist of an extensive set of hourly spot and day-ahead electricity forward prices from the wholesale Pennsylvania, New Jersey, Maryland (PJM) electricity market for the period from June 2000 to December 2001. By using hourly spot price information as well as day-ahead forward prices for each hour, this high-frequency data set offers a near-ideal way to study the properties of electricity spot and forward prices. In particular, by studying prices at a hourly level, we may be able to identify economic effects not visible with data at a daily or monthly level.

A number of interesting results emerge from this analysis. We find that electricity

[1]For example, see *The Wall Street Journal*, May 16, 2002.

forward prices tend to be lower than expected spot prices on average, consistent with the classic hedging-pressure literature (Keynes (1930), Hicks (1939), Cootner (1960), and others). The pattern, however, varies significantly throughout the day. For example, forward premia are much higher during the early morning and afternoon hours. Particularly surprising is the size of the forward premia. On average, the expected spot price is nearly 6.4% higher than the day-ahead forward price, and is more than 12% higher for a number of hours. This represents a huge premium for bearing spot price risk for one day.

On the other hand, we demonstrate that the results about the size of the average premia depend heavily on a few extreme observations. In particular, we show that median forward prices are actually higher than median spot prices for all but a few of the early morning hours. In this sense, the average forward premium is not typical. These results suggest that the forward premium represents compensation for bearing the "peso-problem" risk of rare but catastrophic shocks in electricity prices. In this sense, the strategy of buying electricity in the spot market rather than in the day-ahead forward market has features in common with the strategy of writing out-of-the money options.

To understand better the properties of the premia embedded in electricity forward prices, we examine whether these premia are related to several measures of the risks facing electricity market participants. These include the volatility of unexpected changes in prices and quantity demanded, as well as the risk of large price spikes as demand approaches system capacity. These economic measures are motivated by important recent theoretical work on electricity spot and forward prices by Bessembinder and Lemmon (2002), and Routledge, Seppi, and Spatt (2001). We find clear evidence that forward premia are related to these risk measures. In particular, increases in forecasted demand have a strong positive effect on forward premia. Price and quantity uncertainty have a significantly negative effect on premia. These results support rational price setting in these markets and are consistent with the general implications of Routledge, Seppi, and Spatt and of Bessembinder and Lemmon.

As an additional test for the presence of forward premia, we examine the relative volatility of forward and expected spot prices. In contrast with the common belief that derivative prices are too volatile relative to fundamentals, we find that electricity forward prices are often much less volatile than expected spot prices, corroborating that there are premia in electricity forward prices. Interestingly, the results suggest that forward premia are the largest during the peak 12 Noon to 9 P.M. period. This effect is robust even after controlling for the possible impact of illiquid forward prices in the data set. This evidence is again consistent with market rationality.

This paper contributes to the rapidly growing literature on electricity contract prices. Bessembinder and Lemmon (2002) develop an equilibrium model of electricity spot and forward prices in a production economy and provide preliminary empirical evidence supporting the model. Routledge, Seppi, and Spatt (2001) present a competitive rational expectations model for electricity prices in a setting where storable commodities such as gas can be converted into electricity. Their model has a number of intriguing implications for the empirical properties of electricity prices. Other papers focusing on energy contracts include Gibson and Schwartz (1990), Amin, Ng, and Pirrong (1995), Jaillet, Ronn, and Tompaidis (1997), Kaminski (1997), Eydeland and Geman (1998), Pilipovic and Wengler (1998), Pirrong and Jermakyan (1999), Kellerhals (2001), Escribano, Peaea, and Villaplana (2002), Banerjee and Noe (2002), and Lucia and Schwartz (2002). More recent theoretical work on the relation between forward and expected spot prices for general commodities includes Breeden (1980, 1984), Richard and Sundaresan (1981), Hirshleifer (1988, 1990), Hirshleifer and Subrahmanyam (1993), Routledge, Seppi, and Spatt (2000), and others. Recent empirical evidence about forward and expected spot prices for storable commodities includes Hazuka (1984), Jagannathan (1985), French (1986), and Fama and French (1987). We extend the empirical literature by studying the properties of electricity spot and forward prices using the high-frequency PJM data set and documenting risk-factor-related time variation in electricity forward premia.

The remainder of this paper is organized as follows. Section 2 describes the PJM spot and day-ahead forward markets. Section 3 describes the data used in the study. Section 4 discusses the pricing of electricity forward contracts. Section 5 examines the properties of unconditional forward premia. Section 6 presents the regression results for the conditional analysis of forward premia. Section 7 presents the volatility tests for forward premia. Section 8 summarizes the results and makes concluding remarks.

2. THE PJM MARKET

In this section, we begin by describing the structure and functions performed by the PJM market. We then discuss the different classes of market participants and how their respective supply and demand profiles vary over time. We next explain how the PJM spot and forward markets operate. Finally, we discuss the broad types of economic risks faced by PJM market participants and consider ways in which they may affect electricity spot and forward market prices.

2.1 The PJM System

PJM Interconnection L.L.C. was established in 1997 as the first bid-based energy market in the United States. It has since evolved into the largest deregulated wholesale electricity market in the world. Currently, the PJM system oversees the electricity production, transmission, and trading functions for nearly 300,000 gigawatts each year. The geographical area served by the system covers the mid-Atlantic area including most of Pennsylvania, New Jersey, Delaware, Maryland, Virginia, and Washington D.C. In addition, the system has recently expanded to parts of Ohio, West Virginia, and New York.

The PJM system was established with several key mandates. For example, the system has the responsibility to engender competition among the hundreds of power suppliers in the multi-state service area in an effort to reduce the energy costs of consumers and end users. To this end, PJM created and operates centralized markets for a variety of energy-related contracts such as the electricity spot and forward markets described below. PJM can be viewed as playing the role of an electronic exchange for electricity contracts. Specifically, PJM establishes the trading rules and protocols for market participants, develops and maintains the software, networks, and hardware necessary to run the markets, provides oversight, enforces rules and regulations, establishes market-clearing settlement prices, facilitates the clearing and trade settlement function among market participants, and carries out all general administrative functions for these markets. PJM also plays the role of a clearinghouse in managing the transmission of electricity from generation sources to sinks. Another responsibility of the system is to provide a stable environment for the production and transmission of electricity throughout its service area. As part of this responsibility, the PJM system has some influence over the long-term expansion plans of power generation facilities.

2.2 Market Participants

The massive scale of the PJM energy markets and the system's reputation for cost efficiency and reliability have helped attract many market participants. There are currently more than 200 business entities participating in the PJM energy trading markets. These participants can be placed into five general sectors based on their primary business function. First, the generation-owner sector includes firms that own the generation facilities within the PJM system. Second, the transmission-owner sector includes firms that transfer electricity from the power generators to local distribution stations via high towers and high-voltage lines. Third, the electric-distribution sector, which consists primarily of municipalities, sends electricity from the high-voltage transmission lines to homes, factories, and businesses via local electricity lines. The fourth sector includes groups of retail end users. Finally, the other-supplier sector includes the remaining market participants who are typically marketers or power trading firms.

Intuitively, it would seem that some of these sectors could be identified as either natural buyers or sellers of electricity. For example, the generation owners are generally long electricity generation capacity and want to sell to the buyer with the highest bid. Local utilities are typically buyers and want to find the cheapest source of electricity. Surprisingly, however, there are actually very few firms within the PJM system that can be viewed exclusively as buyers or sellers of electricity. Extensive discussions with PJM officials indicate that firms in the system tend to appear on both sides of the market over time. As an example, consider an electricity generation firm that experiences equipment failure. This firm might find that it needs to buy electricity from the market to fulfill commitments to customers. Transmission owners and electric distributors are required to fill the load requirements at designated power distribution nodes. When their own production is not sufficient to meet demand, these firms must enter the market to buy electricity.[2] Alternatively, when these firms have excess capacity, they often enter the market to find a buyer and sell electricity. Even municipalities and local electric utilities may be in the market selling excess supply at some point in time. Finally, the other-supplier sector includes many power marketing or trading firms. These firms neither generate electricity nor take delivery of electricity, but attempt to generate profits by providing liquidity to the market and/or speculating and/or arbitraging price movements. Thus, at any point in time, these firms may be buyers, sellers, or both.

Because of these considerations, it is difficult to map the PJM market into a simple market microstructure framework where each participant has a specific role such as a pure hedger or speculator. Depending on market conditions, each participant may be buying or selling power. In fact, our discussions with PJM officials suggest that because of the dynamic structure of the power market, many firms actually oscillate back and forth between various roles several times a day. In summary, the PJM trading market is complicated with many types of market participants whose trading motives differ and change over time and with market conditions.

2.3 The PJM Spot and Forward Markets

The PJM system offers two basic types of markets in which participants may trade electricity. The first functions as a spot market and is referred to as the real-time market. In this market, participants can enter sale offers and purchase bids for electricity on a real time basis, and depending on circumstances, electricity can often be generated and transmitted within minutes of the spot trade. In this market, PJM functions as an auctioneer in the electronic auction market by matching bids and offers and in determining market-clearing prices. The market-clearing price is referred to as the locational marginal price. One slight difference between this market-clearing price and that determined by, say, a NYSE market specialist, is that the location of the electricity buyer and seller may have an influence on the price. Specifically, if the electricity traded can be transmitted directly from seller to buyer without experiencing line congestion, voltage constraints, or thermal limits, the locational marginal price is simply the price that equates supply and demand. On the other hand, if there are limitations on deliverability, then the cost to the buyer might be higher than the best offer. In this sense, this market has some features in common with markets for agricultural commodities in which location may affect prices because of the cost of transportation. To mitigate any possible effects of location on prices, we use spot prices averaged over a large portion of the PJM system's service area in the analysis. Keep in mind, however, that these locational issues may have the effect of slightly increasing the volatility of spot prices observed in the market.

[2]Failure to conform with the provisions of their contract with PJM may lead to the firm losing their membership in the system and being shut out of the trading market.

The second market in the PJM system is a forward market referred to as the day-ahead market. In this market, participants submit offers to sell and bids to purchase electricity for delivery at any specified hour during the subsequent day. Just prior to 4 P.M. of the trading day, PJM clears the market by evaluating which offers to accept in order to fill the bids and determining the market-clearing prices. By 4 P.M., PJM announces the 24 hourly clearing prices for the next day's delivery, and issues production schedules that indicate hourly output levels for the generating plants and notifies buyers of their filled orders (announces the trades). Thus, this market functions as a standard forward market in which market participants can hedge against price risk by entering into forward purchases or sales of electricity. This market functions in parallel with the spot market. For example, a firm that purchases electricity forward may find the next day that they need less than they have contracted for. In this case, they likely will try to sell the excess in the spot market. Similarly, a firm that contracts to sell forward the next day may experience an unexpected generating plant maintenance problem. In this case, they may need to enter the spot market to purchase enough power to meet their contractual commitments.

It is important to note that each day, there are 24 distinct prices reported for both the spot and forward markets. For example, average prices are reported for all spot transactions between Midnight and 1 A.M., between 1 A.M. and 2 A.M., etc. Thus, there are 24 hourly spot prices reported each day. In addition, at 4 P.M. each day, there are 24 forward prices announced. These consist of the market-clearing forward price for power to be delivered between Midnight and 1 A.M. of the next day, between 1 A.M. and 2 A.M. of the next day, etc. Thus, the fundamental unit of analysis in our study is an hour; each day provides us with 24 separate observations of spot and forward prices. It is this high-frequency nature of the data that allows us to study the relation between spot and forward electricity prices in more detail than in previous studies.[3] In particular, examining day-ahead contracts for individual hours provides much more data than would be possible using month-ahead contracts on daily averaged prices.[4]

[3]Other empirical work on electricity prices includes Escribano, Peaea, and Villaplana (2002) and Lucia and Schwartz (2002) who use the daily average of prices across all 24 hours. Kellerhals (2001) is the only paper we are aware of that also treats price series separately across hours. His paper, however, has a different focus in that his objective is to calibrate a stochastic volatility model of the forward rate.

[4]Fama and French (1987) argue that detecting the presence of premia in forward prices is difficult because there are a limited number of contract maturities available for study and the variances of realized premia are large. Although Bessembinder and Lemmon (2002) find evidence of significant premia in month-ahead electricity forward contracts, they also point out the limitations inherent of having to rely on a small sample.

2.4 Economic Risks

Electricity suppliers and buyers in the PJM market are exposed to a number of economic risks. In important recent theoretical work by Bessembinder and Lemmon (2002), several key measures of economic risk are identified and play a central role in the determination of equilibrium spot and forward prices. These economic risks also play an important role in the recent paper by Routledge, Seppi, and Spatt (2001) who show that their equilibrium model produces prices which display many of the real-world properties of actual electricity prices. Motivated by these results, our analysis focuses on these key economic risk measures.

As shown by Bessembinder and Lemmon (2002), price risk is a major source of uncertainty for both buyers and sellers of electricity. Sellers are concerned that prices may be too low to allow them to generate enough revenue to cover variable and fixed expenses. Buyers are concerned that the cost of sourcing electricity may exceed their ability to recover costs. Both of these may find that the day-ahead electricity forward market offers ways to mitigate their price risk. As discussed earlier, however, the complexity of the market makes it difficult to argue that one side of the market always hedges while the other side always provides insurance against price risk.

Another crucial economic risk is that of quantity uncertainty. This risk arises because of the difficulty in predicting exactly what the total demand for power will be hour by hour. Electricity demand is driven by many factors such as time of day, the number of hours of daylight, temperature, wind speed, weather conditions as well as economic factors such as price and conservation efforts. As we show later, electricity demand can be forecast with a fair degree of precision. There is, however, some residual quantity uncertainty that may create risks for PJM market participants. For example, a buyer who contracts to buy power on the forward market may find that demand is less than anticipated and will not be able to sell as much power to end users. The buyer may then need to sell power on the open market and may suffer losses if the spot price of power drops. Alternatively, a buyer may need to buy power on the spot market is there is a spike in demand due to, say, unseasonably warm weather. The uncertainty about power usage represents a major source of risk that is distinct from price risk. Ultimately, the profits of market participants are driven by the total cost or revenue associated with power which is given by the product of quantity and price. Thus, both types of risk are relevant to market participants.

Another related but major source of risk is that of total demand approaching or exceeding the physical limits of power generation. In these extreme scenarios, the cost of power may spike as less-efficient higher-marginal-cost power generation technologies are brought on line to meet increasing demand. As the total amount of power demanded approaches system capacity, desperate buyers may bid up the spot cost of power to levels 20 times or more their usual values. These spikes in the cost of power can have disastrous consequences for some market participants as evidenced by the fiscal problems currently faced by the State of California as well as a number of major California electrical utilities. The risk of price spikes as demand approaches system capacity is an extreme type of price risk which may have important implications for the relation between spot and forward prices in the PJM market.

3. THE DATA

The primary data for this study consist of hourly spot and day-ahead electricity forward prices from the PJM markets for the period from June 1, 2000 to December 31, 2001. For each of the 579 days in the sample period, the data set includes the average spot price for each of the 24 hours during the day. In addition, the data set includes the 24 settlement prices determined at 4 P.M. for the day-ahead forward market, where delivery is to be made at the respective hour during the next day. The data represent averages over all of the power delivery nodes for the PJM Eastern hub which consists of most of Delaware, New Jersey, and Pennsylvania. This region represents a large fraction of the population served by the PJM system. The data are provided to us directly from PJM.

Table 1 reports summary statistics for the electricity spot prices. Spot prices are quoted in dollars per megawatt hour ($/MWh). Fig. 1 plots the time series of spot prices for a representative subset of hours. As shown in Table 1, the average spot price varies throughout the day, ranging from a low of about $17 for the early morning hours, to a high of about $53 for the peak late afternoon hours. Table 1 and Fig. 1 also show that there is considerable time series variation in the spot price, particularly during peak hours. For example, the standard deviations for the spot prices exceed $80 for some of the afternoon hours, which is nearly twice the mean value for these hours. Similarly, a number of the maximum spot prices during the late afternoon hours are in excess of $1000, which is more than 20 times the mean values for these hours. These summary statistics demonstrate one of the dominant features of electricity spot prices: their highly right-skewed distribution. This pattern of skewness is consistent with the implications of the model presented in Routledge, Seppi, and Spatt (2001). Note from Table 1 that the hourly spot prices display a fair amount of serial correlation across days, with first-order serial correlation coefficients ranging from 0.25 to 0.59. Although highly significant, these first-order serial correlations are far lower than is the case for other financial time series such as stock prices or interest rates. These serial correlations are also consistent with the time series properties for electricity spot prices implied by Routledge, Seppi, and Spatt.[5]

[5] A few of the spot prices in the data set are negative or zero, representing missing or improperly coded data. To avoid these data measurement problems, we filter out observations for which the spot or forward price is less than $2. This reduces the sample size by only a small fraction of a percent. The results are robust to the cutoff level for the prices.

Table 2 presents summary statistics for the electricity forward prices. These forward prices are quoted in the same units as spot prices ($/MWh). Fig. 2 plots the time series of forward rates for the same hours as shown in Fig. 1. As can be seen, the properties of the electricity forward prices are similar in some ways to those for the spot prices. For example, the average forward prices are comparable in magnitude to the average spot prices given in Table 2 and display the same type of intraday variation. On the other hand, however, there are some key differences between the electricity spot and forward prices. Specifically, the standard deviations of the forward prices are uniformly lower than the corresponding standard deviations for the spot prices, implying that forward prices tend to be less volatile than spot prices. Furthermore, forward prices do not display as much extreme variation as spot prices. In particular, the maximum forward prices are typically much lower than the maximum spot prices, indicating that forward prices have significantly less right skewness. The hourly forward prices are much more serially correlated than the spot prices. The first-order serial correlation coefficients for the hourly forward prices range from 0.39 to 0.84.

In addition to the primary data set of spot and forward prices, we also collect data on electricity usage and weather conditions. In particular, we obtain hourly electrical load or usage data (measured in gigawatt hours) from PJM for the Eastern hub. Fig. 3 plots the time series of loads for the same hours shown in Figs. 1 and 2. As illustrated, the load data is fairly smooth with a strong weekly seasonal. There is also a clear intraday pattern that closely mirrors the intraday patterns observed in spot and forward prices; demand for peak afternoon hours tends to be higher and more volatile than for other hours. Demand during summer (June, July, and August) and winter (December, January, and February) also tends to be higher than during the other seasons. Finally, we also collect data on several indicators of weather conditions such as the daily average temperature in a region closely approximating that covered by the PJM Eastern hub, as well as the wind speed during winter periods. The weather data is obtained from the Philadelphia station of the National Weather Center. The data on electricity loads and weather conditions are used as explanatory variables in the system of vector autoregressions (VARs) used to construct forecasts of key economic time series in the study.

4. FORWARD PREMIA

The literature on the pricing of forward contracts has historically focused on the relation between spot prices and forward prices. There are two primary types of models that appear in this literature. The first is the standard no-arbitrage or cost-of-carry model where an investor can synthesize a forward contract by taking a long position in the underlying asset and holding it until the contract expiration date. If the forward price does not equal the price of the replicating portfolio, then arbitrage profits are possible. Thus, the forward price is linked directly to the current spot price. The classical literature on the cost-of-storage or cost-of-carry model includes Kaldor (1939), Working (1948), Brennan (1958), Tesler (1958), and many others. It is important to note that the no-arbitrage argument underlying this model relies on the ability of an arbitrageur to take a position in the underlying asset and hold it until the contract expiration date. Since electricity is not storable, however, the cost-of-carry model cannot be applied directly to electricity forward prices.

The second general approach used in the literature to model forward prices is based on equilibrium considerations. Examples of this approach include Keynes (1930), Hicks (1939), Cootner (1960), Breeden (1980, 1984), Richard and Sundaresan (1981), Hirshleifer (1988, 1990), Hemler and Longstaff (1991), Hirshleifer and Subrahmanyam (1993), Seppi, Routledge, and Spatt (2000), Bessembinder and Lemmon (2002) and many others. Although a few of these address the pricing of forward contracts on storable commodities, most focus on the implications for the relation between forward and expected spot prices. In particular, this literature has traditionally focused on what is termed the forward premium. Often, the forward premium is defined as the difference between the expected spot price and the forward price. Some recent authors such as French (1986) and Fama and French (1987) focus on percentage forward premia. In either case, however, empirical implications are framed in terms of whether the forward premium is positive or negative.[6] In the literature, the forward premium represents the equilibrium compensation for bearing the price risk of the underlying commodity. Thus, a producer of the underlying commodity might be willing to sell forward at a lower price to avoid spot price risk. In this case, agents who buy forward would earn a premium by providing insurance to producers. The classical literature (Keynes, Hicks, and others), suggests that expected spot prices should typically be higher than forward prices, reflecting hedging-pressure effects. More recently, however, Hirshleifer (1990) provides examples showing that the equilibrium forward premium need not be strictly positive. In summary, this literature implies that forward premia should be fundamentally related to economic risks and the willingness of different market participants to bear these risks. The sign of the average forward premium, however, is indeterminate.

Motivated by this second approach, our objective in this paper is to study how electricity forward prices are related to expected spot prices. In particular, we examine whether there are forward premia in these markets, and if so, what their economic properties are. In doing this, however, it is important to keep in mind the extreme right skewness of electricity spot and forward prices. One key implication of this skewness is that inferences about the forward premium could be overly sensitive to outliers. To address this, we follow the approach used in French (1986), Fama and French (1987), and others by focusing on the percentage forward premium. Specifically, let F_{it} denote

[6] In the classical literature, a positive premium is referred to as normal backwardation while a negative premium is designated as contango.

the electricity forward price observed on day t for delivery during hour i of day $t+1$, and let $S_{i,t+1}$ denote the spot price for hour i of day $t+1$. The percentage forward premium is defined by the expectation

$$FP_{it} = E_t \left[\frac{S_{i,t+1} - F_{it}}{F_{it}} \right]. \tag{1}$$

By expressing the forward premium in percentage terms, we mitigate the effects of price spikes on the results without losing the economic interpretation of FP_{it} as a premium.[7]

The empirical analysis consists of three levels of tests. First, we examine whether there is evidence of forward premia at an unconditional level. Second, we test whether there are conditional or time varying forward premia. Finally, we explore the relation between the volatilities of expected spot and forward prices.

5. UNCONDITIONAL FORWARD PREMIA

To examine whether forward premia are zero on average, we take the sample mean of the expression for the forward premium in Eq. (1) for each hour and test whether these means are significantly different from zero. Thus,

$$E[\ FP_{it}\ ] = \frac{1}{T} \sum_{t=1}^{T} \frac{S_{i,t+1} - F_{it}}{F_{it}}, \tag{2}$$

where the expectation is now unconditional. Table 3 reports the mean values of the forward premia and their corresponding t-statistics, along with other summary statistics. All t-statistics reported are based on heteroskedastic and autocorrelation consistent estimates of the variances. We adopt this approach in light of the implications of Routledge, Seppi, and Spatt (2001) that electricity prices should display conditional heteroskedasticity. Fig. 4 plots the mean values of the forward premia.

As shown, the mean percentage forward premia are almost all positive; 21 out of 24 are positive. Of these, 14 are statistically significant. Although not shown, Bonferroni tests for the joint significance of all 24 means strongly reject the null hypothesis that unconditional forward premia are zero. These results are consistent with the classical hedging-pressure hypothesis that expected spot prices should be higher than forward prices.

[7]We note, however, that most of the results are similar to those reported when the analysis is based on the absolute forward premium rather than the percentage forward premium.

The size of the average forward premia is surprisingly large. Taken over all hours, the average forward premium is 6.4%. This is an extremely large premium given that the forward contract has only a one-day horizon. We note that there is a considerable amount of intraday variation in the mean forward premia. The mean percentage forward premia range from a maximum value of 16% at 2 P.M. to a minimum value of −3% at 8 P.M. Thus, risk premia in the electricity market may experience significant variation over horizons measured in minutes or hours.

It is important to observe, however, that the mean percentage forward premia are significantly affected by the positive skewness of the data. For example, although 21 of the 24 hours have positive means, 19 have negative medians. Furthermore, the medians are all lower than the means. In many cases, the medians are lower than the means by as much as 15% to 20%. It is easily seen from the data that the skewness in the forward premium comes from a small percentage of observations where the realized spot price is much higher than the forward price. This does not invalidate the inferences about the significance of the means, of course, since the standard deviations of the forward premia are incorporated into the test statistic. Furthermore, many of the means are significant even when the significance level is given by Chebyshev's inequality. Rather, these results provide important insights into the nature of electricity forward premia. These premia appear to compensate market participants for bearing the risk of extreme but rare "peso-problem" spikes in the spot price of electricity. Thus, while the median or typical forward premium is negative, the average forward premium is positive. In this sense, the strategy of buying electricity on the spot market is analogous to writing deep out-of-the-money options; the median profit from this strategy is positive, but the strategy can produce disastrous results in rare market scenarios.[8]

6. CONDITIONAL FORWARD PREMIA

To better understand the properties of the premia embedded in electricity forward prices, we examine whether these premia are related to economic risk measures. Finding evidence that forward premia vary systematically through time with these risk measures would provide support for the view that prices in electricity markets represent the outcome of a rational market-clearing process.

6.1 The Conditional Tests

To motivate our conditional tests, note that the realized or ex post forward premium can be expressed as

[8]This option-like feature is consistent with Routledge, Seppi, and Spatt (2001) who argue that the "downstream" nature of electricity can induce option-like effects in electricity spot prices.

$$\frac{S_{i,t+1} - F_{it}}{F_{it}} = E_t\left[\frac{S_{i,t+1} - F_{it}}{F_{it}}\right] + \epsilon_{i,t+1}, \tag{3}$$

where $\epsilon_{i,t+1}$ represents the unexpected component of the realized forward premium and is orthogonal to information at time t. Thus, from Eq. (1), the ex post realization of the forward premium equals the ex ante forward premium FP_{it} plus a residual term uncorrelated with variables in the information set at time t. Using this property, our approach to testing for time variation in forward premia parallels that of French (1986) and Fama and French (1987) in that we regress the ex post realization of the percentage forward premium on a vector of risk factors in the information set at time t. Finding that these ex ante risk measures have explanatory power for the ex post realization indicates there are time varying or conditional forward premia in electricity forward prices.

6.2 The Risk Measures

As discussed in Section 4, the ex ante risk measures are chosen to reflect some of the fundamental economic risks facing electricity market participants. Following Bessembinder and Lemmon (2002), we include measures of price and quantity uncertainty as well as a measure of risk of price spikes occurring as demand approaches system capacity.

To measure the risk of unexpected price changes facing market participants at time t, we adopt the following procedure. First, we estimate the expected change in the spot price of electricity from day t to $t+1$ using only information available to market participants prior to PJM's announcement of settlement forward prices at 4 P.M. on day t. The estimate of the expected price change for each hour is obtained from a system of vector autoregressions (VARs). Subtracting the expected price changes from realized price changes gives a time series of unexpected price changes. We then estimate a simple GARCH(1,1) model for the time series of unexpected price changes.[9] The GARCH estimate of the conditional variance of unexpected price changes (where only information known prior to 4 P.M. is used to form this estimate) is then used in the forward premium regressions as the ex ante price risk measure. We denote this risk measure by VS_{it}.

To be more specific about the details of this procedure, we note that the VARs are estimated separately for each of the 24 hours. The explanatory variables used in the VARs are the spot prices and load quantities for the PJM system for the each

[9] The empirical results are very similar using alternative measures of the conditional volatility of unexpected price changes such as an exponentially weighted average of past innovations or a rolling window estimator. Furthermore, the results are also similar when the volatility measures are based on price changes rather on unexpected price changes.

hour during the 24 hours previous to 4 P.M. Also included are monthly and holiday/weekend dummies to control for seasonal and day-of-the-week regularities. Given the importance of weather conditions on electricity usage, we include several weather-related variables. The first is the difference between the average temperature during a day and the historical average temperature for that day. The second is the absolute deviation of the average temperature during a day from a "comfortable" benchmark of 68 degrees. The third measures the difference between the daily maximum wind speed during winter and 11.5 miles per hour. If the daily maximum is above 11.5 miles per hour, this variable equals the difference. If the daily maximum is less than 11.5 miles per hour, this variable takes a value of zero. During spring, summer, and fall, this variable always takes a value of zero irrespective of the wind speed. Table 4 reports the R^2s for the VARs forecasting price changes. As shown, much of the spot price change from day t to $t+1$ is predictable; the R^2 range from a minimum of 0.250 for 9 A.M. to a maximum of 0.630 for 9 P.M.

To provide a measure of demand or quantity uncertainty, we follow essentially the same procedure as that described above for the volatility of unexpected price changes. Specifically, we use the same VAR framework to forecast the expected electricity load or quantity used within the PJM system. The R^2s for the VAR forecasts of the electricity loads are also reported in Table 4. Subtracting the expected loads from realized loads gives a time series of innovations in the quantity of power used. We again fit a GARCH(1,1) model to these innovations to obtain estimates of the conditional volatility of unexpected changes in the load.[10] The GARCH estimate, based only on information prior to the 4 P.M. settlement time on day t, is used as the ex ante measure of quantity uncertainty. We denote this GARCH estimate of the conditional volatility of unexpected changes in load by VL_{it}.

The third risk measure used in the forward premium regressions attempts to capture the risk that an extreme price shock or spike in the spot price may occur. As was shown previously, spikes are a distinguishing feature of electricity spot prices. Historically, price spikes tend to occur during periods when electricity demand approaches system capacity. Thus, the difference between maximum system capacity and expected demand should proxy for the possibility of spikes occurring. One difficulty, however, is that we do not have information about the system's maximum capacity. Under the assumption that this maximum is constant throughout the sample period, however, this difference becomes a constant minus the expected load. Since the constant goes into the regression intercept, we simply use the expected load from the VAR forecasting model described above as the proxy of the possibility of spikes occurring. We designate the expected load by EL_{it}.

[10] Again, the results are not sensitive to the specific conditional volatility model or to whether we use changes or unexpected changes in the load.

6.3 Empirical Results

Given these explanatory variables, we estimate the regression

$$\frac{S_{i,t+1} - F_{it}}{F_{it}} = a_i + b_i \ VS_{it} + c_i \ VL_{it} + d_i \ EL_{it} + \epsilon_{i,t+1}, \tag{4}$$

for each of the 24 hours individually. We also estimate the regression using the entire pooled data set (in this regression, the coefficients are the same across i). The regression results are reported in Table 5.

Focusing first on the results for the entire data set, Table 5 shows that all three of the economic risk factors are highly statistically significant. The coefficient for for the price uncertainty measure is negative with a t-statistic of -6.82, indicating that the forward premium is a decreasing function of this risk measure. This negative sign is consistent with the implications of Bessembinder and Lemmon (2002); hypothesis 1 of their paper implies that the forward premium decreases in the anticipated variance of power prices. Our results provide independent empirical support of their findings. The individual hourly regressions show that this negative relation holds for 24 of the 24 hours, and is statistically significant for 13 hours. Interestingly, there is considerable variation throughout the day in terms of the relation between forward premia and price uncertainty. For example, the strongest negative relation occurs during the early morning hours and the midday and early afternoon hours. These results provide strong support for the hypothesis that equilibrium electricity spot and forward prices respond rationally to changes in market uncertainty.

The coefficient for quantity uncertainty in the regression using the entire data set is likewise negative and highly significant. In the individual hourly regressions, the load volatility is negative for 16 of the 24 hours, but is only significant for 7 of the hours. There are no hours for which this coefficient is significantly positive. There is again an interesting pattern of variation in this coefficient throughout the day. For example, load volatility is most significant during both the early morning and afternoon hours. Thus, the hours when this risk measure is most significant do not coincide perfectly with the hours when the price volatility measure is most significant. This negative relation is also consistent with the implications of Bessembinder and Lemmon (2002) who argue that this relation should be negative for some parameter ranges. Again, these results support the hypothesis that market electricity prices respond to fundamental economic risks.

The coefficient for expected demand is positive and highly significant in both the pooled and individual regressions. For the entire data set, the coefficient for expected demand has a t-statistic of 15.28. This risk measure is positive for all 24 individual hourly regressions, and is significant for 15 hours. Table 5 shows that this variable is most significant during the 7 A.M. to 6 P.M. period, but is also significant during the early A.M. hours. Interestingly, this risk measure is not significant for any of the evening hours after 6 P.M. Recall that this variable provides a proxy for the risk of electricity demand approaching system capacity and increasing the risk of a large upward spike in spot prices. These results demonstrate that compensation for this risk is a fundamental determinant of the relation between electricity spot and forward prices. Again, these results are also consistent with the implications of Bessembinder and Lemmon (2002) who predict a positive sign for this coefficient.

Finally, note that the R^2 for these regressions range from near zero for the later evening hours to a roughly seven percent for the 2 P.M. to 3 P.M. period. Recall that the dependent variable in these regressions is the ex post measure of the forward premium rather than the ex ante measure. As discussed by French (1986) and Fama and French (1987), the difference between the ex ante and ex post forward premium measures can add a significant amount of noise to the dependent variable in these types of regressions. In this sense, R^2s as high as seven percent suggest a fairly high level of time varying predictability in electricity forward premia.

7. VOLATILITY ANALYSIS

As an alternative way of testing for the presence of premia in electricity forward prices, we use an approach that compares the volatilities of forward and expected prices. In particular, note that under the null hypothesis that the forward premium FP_{it} equals zero, Eq. (1) becomes

$$0 = E_t \left[\frac{S_{i,t+1} - F_{it}}{F_{it}} \right], \tag{5}$$

which implies

$$F_{it} = E_t \left[\ S_{i,t+1} \ \right]. \tag{6}$$

Thus, under the null hypothesis, the forward price equals the expected spot price. Consequently, all moments of the left-hand and right-hand sides of Eq. (6) should be equal. In this approach, we focus on the second moment.

This implication is directly testable by comparing the unconditional volatilities for the forward prices with those for the expected spot prices given from the VAR model described in the previous section. To implement this test, Table 6 reports the unconditional standard deviations of the day-to-day changes in the individual forward prices and of the corresponding changes in the VAR estimates of day-ahead expected spot prices. These standard deviations are also plotted in Fig. 5.

As shown in Table 6 and Fig. 5, the volatilities of changes in the forward prices display a somewhat different pattern from the volatilities of changes in the expected spot prices. In particular, the two volatilities are very similar during the first 11 hours of the day. From 12 Noon to 9 P.M., however, the volatility of changes in expected spot prices is much higher than that for changes in forward prices. For a number of these hours, the volatility of changes in expected spot prices is more than 50% higher. After 9 P.M., the two volatilities are again very similar.

These patterns in the volatilities clearly suggest that there are premia in the electricity forward prices. In addition, they suggest that these premia are concentrated during a nine-hour period during the day. This period includes the hours of the heaviest power usage and highest average prices. Thus, it makes intuitive sense that the 12 Noon to 9 P.M. period might represent the period when PJM market participants face the greatest economic risks. It is also interesting to note that this period has substantial overlap with the hours where the conditional forward premia are statistically most significant. To provide a more formal test for the presence of forward premia, we note that under the null hypothesis that the two volatilities are equal and, thus, that any differences are simply due to independent measurement errors, the t-statistic for the mean volatility difference across hours is 3.18. Thus, the null hypothesis of equal volatilities is easily rejected, implying that electricity forward prices contain premia.

As a robustness check on the results, we note that a possible explanation for finding forward prices to be less volatile during some periods might be that they are not updated as frequently as spot prices. Specifically, if the forward market is less liquid that the spot market, then reported forward prices might not be updated and may not move as much as spot prices. To check this, we redo the tests using only data for days when both forward and spot prices change from the previous day. Although not shown, these results are virtually identical to those in Table 6.

8. CONCLUSION

This paper studies the pricing of electricity forward contracts in the day-ahead forward market and their relation to the corresponding spot prices. Using an extensive set of hourly spot and day-ahead forward prices, we are able to confirm the existence of forward premia and establish the link between these premia and measures of economic risk faced by market participants.

Following French (1986), Fama and French (1987) and others, we focus on percentage premia. We find that the average premia are positive for most hours, consistent with the classical hedging pressure literature (Keynes (1930), Hicks (1939), Cootner (1960), and others). The size of the average premia varies throughout the day, ranging from -3% to 16%, and the overall average premium across all 24 hours is 6.4%. However, we find the opposite pattern for median premia. For most of the hours, the median premia are negative, and the overall median across hours is -6.3%. This suggests that the forward premium represents compensation for bearing the "peso-problem" risk of rare but catastrophic shocks in electricity prices. Buying electricity is the spot market is similar to writing out-of-the-money options in the sense that most of the time, both investment strategies generate profits. Once in a while, however, they will lose large amounts with potentially disastrous consequences.

We further examine whether the forward premia reflect compensation for risk taking by regressing forward premia on several measures of the risk faced by market participants. Our choice of risk measures is suggested by recent theoretical work by Bessembinder and Lemmon (2002). We include volatilities of unexpected spot price changes to capture price uncertainty, volatilities of unexpected load changes to capture quantity uncertainty, and the forecast load/quantity to proxy for the likelihood of approaching the system's capacity limit. We find that for both time series regressions for individual hours as well as the pooled cross-sectional regression for all 24 hours, these risk measures play a significant role in explaining the forward premium. Specifically, a higher forecast demand leads to higher premia, and higher volatilities in unexpected spot price and demand changes lead to lower forward premia. These finding are consistent with the predictions from the model of Bessembinder and Lemmon.

We provide additional insights about the properties of forward premia by comparing the standard deviations of changes in the forward and expected spot prices. We show that changes in forward prices are often less volatile than changes in the corresponding expected spot prices. For example, during the peak hours from 12 Noon to 9 P.M., the volatilities of expected spot price changes are 26% to 76% higher than those for forward price changes. This is robust even after controlling for the possible impact of illiquid forward prices in the data. These results provide additional empirical support for the existence of time varying forward premia.

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Table 1

Summary Statistics for Hourly Spot Prices. This table presents summary statistics for the hourly spot electricity prices reported by PJM. Prices are reported in dollars per megawatt hour. AR_1 denotes the first-order serial correlation coefficient. The sample consists of daily observations for each of the 24 hourly spot prices during the June 1, 2000 to December 31, 2001 period.

Hour	Mean	Std. Deviation	Minimum	Median	Maximum	AR_1
1	19.88	9.49	2.10	16.66	69.42	0.55
2	18.82	9.61	2.26	15.70	71.28	0.56
3	17.58	8.60	2.83	15.22	69.67	0.55
4	17.07	7.90	2.17	14.86	70.41	0.52
5	17.25	8.30	2.64	15.03	79.46	0.45
6	20.11	10.04	2.07	17.15	94.39	0.44
7	28.73	18.64	2.12	21.95	117.87	0.43
8	33.90	24.37	4.17	24.92	157.48	0.33
9	33.28	19.96	2.93	26.99	151.90	0.25
10	37.50	20.72	8.39	32.45	164.39	0.27
11	42.18	24.84	10.52	37.14	249.68	0.41
12	45.14	51.82	7.08	35.93	846.50	0.48
13	46.11	68.51	2.63	33.28	1005.53	0.51
14	51.26	83.84	7.94	35.78	1020.28	0.59
15	48.62	87.18	5.19	30.96	1019.97	0.59
16	46.12	87.43	7.80	28.69	1019.72	0.39
17	48.90	76.28	12.60	35.64	1019.74	0.53
18	53.47	69.44	6.13	42.73	1019.75	0.57
19	45.57	54.05	12.82	35.76	801.55	0.28
20	42.06	34.60	13.06	34.99	645.32	0.32
21	45.76	49.11	13.18	35.75	994.98	0.41
22	38.02	24.84	12.66	31.00	352.38	0.40
23	27.75	14.07	8.11	22.82	116.32	0.45
24	22.44	11.74	6.66	18.78	157.24	0.50
Overall	35.51	47.75	2.07	24.80	1020.28	0.59

Table 2

Summary Statistics for Hourly Day-Ahead Forward Prices. This table presents summary statistics for the hourly day-ahead electricity forward prices reported by PJM. Prices are reported in dollars per megawatt hour. AR_1 denotes the first-order serial correlation coefficient. The sample consists of daily 4 P.M. observations for each of the 24 hourly day-ahead contract prices during the June 1, 2000 to December 31, 2001 period.

Hour	Mean	Std. Deviation	Minimum	Median	Maximum	AR_1
1	20.23	7.83	5.00	18.11	50.01	0.77
2	17.77	6.81	3.13	15.84	45.20	0.80
3	16.61	6.51	2.50	15.00	43.98	0.84
4	16.44	6.67	2.86	14.99	43.22	0.84
5	16.96	7.10	3.00	15.01	46.39	0.82
6	20.16	8.95	3.01	17.94	50.00	0.75
7	30.30	18.32	2.94	24.37	150.00	0.67
8	34.85	19.96	5.01	28.83	140.01	0.68
9	36.17	17.09	11.01	32.71	130.01	0.67
10	39.07	16.68	13.45	37.49	125.00	0.62
11	41.97	19.36	14.95	40.28	198.10	0.64
12	43.19	27.36	14.47	40.00	390.93	0.69
13	43.12	35.67	14.68	38.15	545.46	0.68
14	45.08	44.03	13.75	38.63	646.81	0.72
15	45.67	55.40	13.30	36.06	818.54	0.74
16	45.87	56.65	13.87	35.82	859.05	0.73
17	49.42	55.28	15.03	40.01	779.38	0.65
18	55.72	46.59	15.02	47.71	599.22	0.61
19	51.03	33.46	14.91	44.78	450.01	0.76
20	48.05	29.38	15.06	43.17	416.27	0.73
21	46.63	30.37	15.10	42.26	498.01	0.39
22	38.61	18.13	15.00	35.90	185.90	0.66
23	29.46	12.98	12.68	26.59	112.86	0.64
24	23.62	9.86	11.00	20.40	74.96	0.75
Overall	35.87	32.14	2.50	29.97	859.05	0.64

Table 3

Unconditional Tests for the Presence of Forward Premia in Electricity Forward Prices. This table presents the mean realized percentage forward premium for each of the 24 day-ahead electricity forward contracts along with their t-statistics. The t-statistics are based on autocorrelation and heteroskedasticity consistent estimates of the variances. Also reported are the median estimates of the realized percentage forward premia. The realized percentage forward premium equals 100 times the ratio

$$\frac{S_{i,t+1} - F_{it}}{F_{it}}.$$

Hour	Mean	t-statistic	Median
1	1.60	0.95	−2.98
2	9.36	4.26	1.54
3	12.89	4.25	3.70
4	11.18	4.36	2.39
5	9.74	3.86	1.01
6	7.47	3.49	−0.16
7	12.26	3.67	8.71
8	11.30	3.81	−9.29
9	3.05	1.11	−14.69
10	5.44	2.11	−10.58
11	8.48	3.36	−5.94
12	8.41	3.01	−11.44
13	10.10	3.09	−10.99
14	15.52	4.30	−4.93
15	8.87	2.54	−10.05
16	4.08	1.00	−12.66
17	7.65	2.42	−7.16
18	2.68	0.87	−14.51
19	−2.77	−0.74	−18.97
20	−3.41	−1.11	−18.79
21	5.18	1.59	−9.99
22	5.16	1.88	−7.86
23	0.16	0.07	−6.87
24	−0.26	−0.12	−5.07
Overall	6.37	4.60	−6.31

Table 4

The R^2s from the VARs Forecasting Next-Day Spot Prices and System Loads. This table reports the R^2s from the VARs used to forecast the hourly spot electricity prices and loads. The VARs for the spot price $S_{i,t+1}$ and the load $L_{i,t+1}$ include dummy variables D_j for month and day of the week/holidays, the 24 hourly spot prices and loads for the 24-hour period immediately preceeding the 4 P.M. forward market settlement time, and the three weather variables W_j described in the paper,

$$S_{i,t+1} = a + \sum_{j=1}^{12} b_j\ D_{jt} + \sum_{i=1}^{15} c_i\ S_{it} + d_i\ L_{it} + \sum_{i=16}^{24} c_i\ S_{i,t-1} + d_i\ L_{i,t-1} + \sum_{j=1}^{3} e_j\ W_j + \epsilon_{t+1},$$

$$L_{i,t+1} = a + \sum_{j=1}^{12} b_j\ D_{jt} + \sum_{i=1}^{15} c_i\ S_{it} + d_i\ L_{it} + \sum_{i=16}^{24} c_i\ S_{i,t-1} + d_i\ L_{i,t-1} + \sum_{j=1}^{3} e_j\ W_j + \epsilon_{t+1}.$$

Hour	Spot Price VAR	Load VAR
1	50.32	89.64
2	48.27	88.47
3	48.35	87.16
4	47.08	85.59
5	39.53	82.96
6	39.58	82.49
7	43.20	84.52
8	42.87	87.23
9	25.02	86.41
10	26.45	85.32
11	41.22	85.05
12	57.07	84.86
13	59.30	84.55
14	59.70	84.60
15	49.43	84.23
16	45.99	83.49
17	53.48	81.42
18	60.00	78.52
19	39.52	74.92
20	55.51	71.74
21	62.98	71.91
22	41.15	72.61
23	26.83	71.25
24	37.17	70.46

Table 5

Results from Regressions of Realized Percentage Forward Premia on Economic Risk Measures. This table reports the results from individual hourly time-series and pooled time-series cross-sectional regressions of realized percentage forward premia on GARCH(1,1) estimates of the conditional volatilities of unexpected spot price changes VS_t and load changes VL_t as well as the forecasted load EL_t.

$$\frac{S_{i,t+1} - F_{it}}{F_{it}} = a_i + b_i \; VS_t + c_i \; VL_t + d_i \; EL_t + \epsilon_{i,t+1}$$

Hour	a	b	c	d	t_a	t_b	t_c	t_d	R^2
1	−9.92	−0.61	−48.04	3.49	−0.70	−1.17	−2.18	2.74	2.55
2	−11.10	−0.31	−59.02	4.85	−0.57	−0.59	−2.31	2.76	2.53
3	−8.59	−0.86	−28.61	3.91	−0.41	−1.36	−0.68	2.10	1.06
4	−19.15	−1.99	31.57	3.07	−0.81	−2.73	0.62	1.59	1.71
5	−4.32	−2.11	55.19	0.14	−0.18	−4.26	1.19	0.06	2.57
6	−17.61	−1.74	18.50	3.09	−0.70	−3.99	0.46	1.70	3.21
7	80.96	−2.44	−287.40	10.56	1.27	−3.64	−2.30	4.73	4.44
8	−89.70	−0.80	−80.68	14.02	−2.22	−1.39	−1.17	9.10	5.75
9	−41.70	−1.98	14.20	5.86	−1.94	−2.49	0.57	4.72	2.53
10	−71.58	−0.48	8.47	6.57	−3.81	−0.59	0.45	4.51	2.59
11	−50.92	−1.89	−17.17	8.55	−2.32	−2.49	−1.04	6.03	4.92
12	−92.40	−0.29	−28.31	10.17	−4.69	−2.70	−2.10	5.64	6.38
13	−86.91	−0.16	−28.04	9.76	−3.85	−2.08	−2.35	4.60	4.59
14	−103.18	−0.13	−41.02	12.32	−4.25	−3.10	−2.83	5.37	7.47
15	−111.14	−0.13	−28.78	12.07	−3.95	−3.47	−2.25	4.33	7.72
16	−107.99	−0.32	−4.69	10.51	−2.85	−3.49	−0.40	3.01	5.81
17	−57.30	−0.14	−18.66	6.78	−2.24	−1.29	−1.48	2.83	3.09
18	−39.69	−0.22	−12.94	4.79	−1.54	−2.19	−1.47	2.15	2.47
19	−15.39	−0.33	−12.39	2.79	−0.61	−3.17	−1.30	1.39	0.82
20	−1.22	−1.11	21.69	0.24	−0.04	−1.47	1.83	0.12	1.46
21	−74.17	−0.22	12.68	5.81	−1.45	−0.74	0.96	1.27	2.93
22	3.52	−0.96	7.54	1.04	0.16	−1.11	0.55	0.50	0.34
23	26.38	−1.70	−13.13	0.28	1.18	−1.25	−1.39	0.17	0.83
24	−31.46	−0.29	−5.62	3.56	−1.49	−0.19	−0.53	1.62	0.92
Pooled	−38.60	−0.17	−17.94	5.27	−12.07	−6.82	−6.95	15.28	1.80

Table 6

Volatility Tests for the Presence of Forward Premia in Electricity Forward Prices. This table presents the standard deviations of changes in the expected spot prices from the VAR forecasting model and changes in the forward price for each hour. Standard deviations are reported in dollars per megawatt hours. Also reported are the differences and ratios of these volatilities. The averages reported are averages over the 24 hours. The t-statistic for the average difference is computed using the standard deviation of the volatility differences taken over all 24 hours.

Hour	Volatility of Changes in Expected Spot Price	Volatility of Changes in Forward Price	Difference in Volatilities	Ratio of Volatilities
1	4.98	5.34	−0.36	0.933
2	4.79	4.33	0.46	1.106
3	4.19	3.72	0.47	1.126
4	3.69	3.79	−0.10	0.974
5	3.70	4.27	−0.57	0.867
6	4.90	6.31	−1.41	0.777
7	10.83	14.80	−3.97	0.732
8	15.43	15.92	−0.49	0.969
9	10.47	13.91	−3.44	0.753
10	11.86	14.63	−2.77	0.811
11	16.23	16.44	−0.21	0.987
12	35.96	21.39	14.57	1.681
13	47.04	28.43	18.61	1.655
14	58.29	33.03	25.26	1.765
15	58.24	40.04	18.20	1.454
16	62.43	41.35	21.08	1.510
17	57.85	46.03	11.82	1.257
18	55.98	41.13	14.85	1.361
19	39.85	23.26	16.59	1.713
20	31.37	21.63	9.74	1.450
21	44.29	33.47	10.82	1.323
22	17.96	14.93	3.03	1.203
23	6.74	11.06	−4.32	0.609
24	6.94	7.01	−0.07	0.990
Average	25.58	19.42	6.16	1.17
t-Statistic for Ave. Difference			3.18	

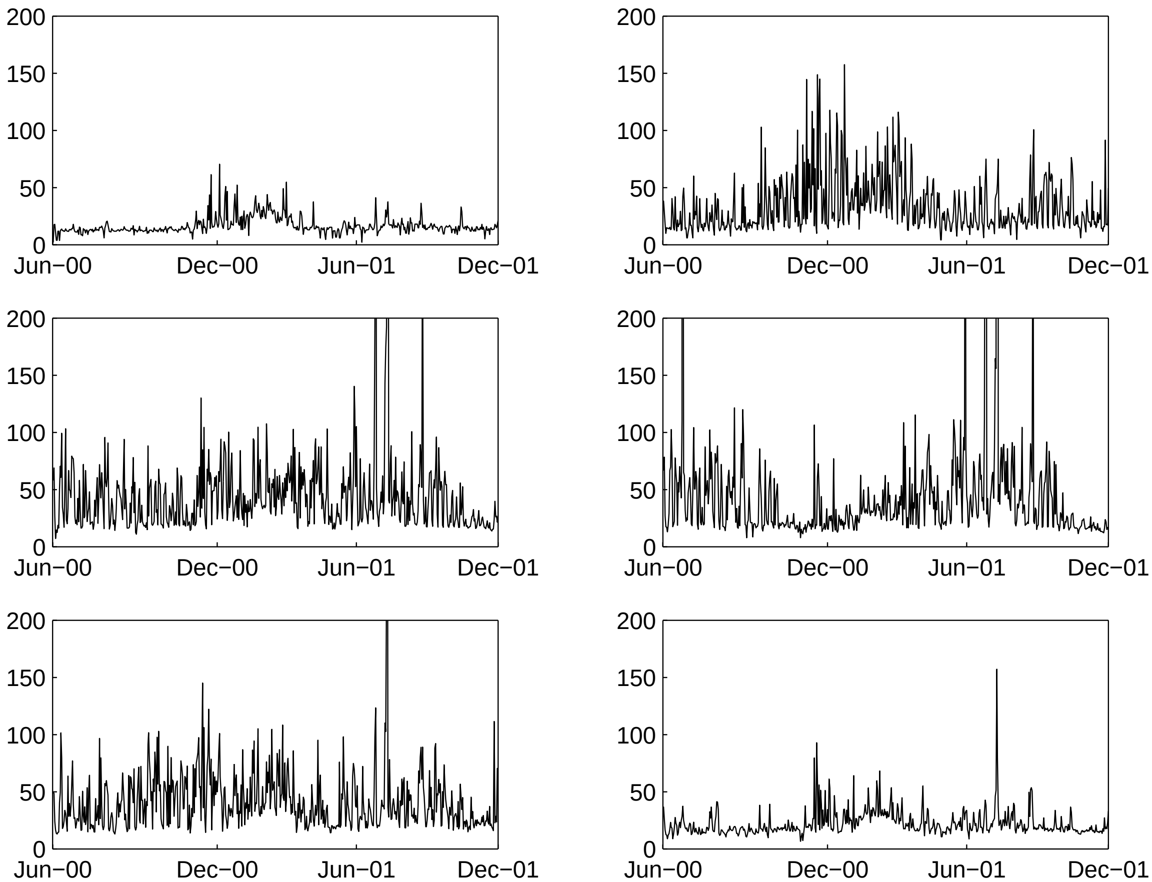

Fig. 1. This figure plots the time series of electricity spot prices for selected hours. From left to right, the top panels plot the spot prices for 4 A.M. and 8 A.M.; the middle panels, for 12 Noon and 4 P.M.; the bottom panels, for 8 P.M. and 12 Midnight. Prices are in dollars per megawatt hour.

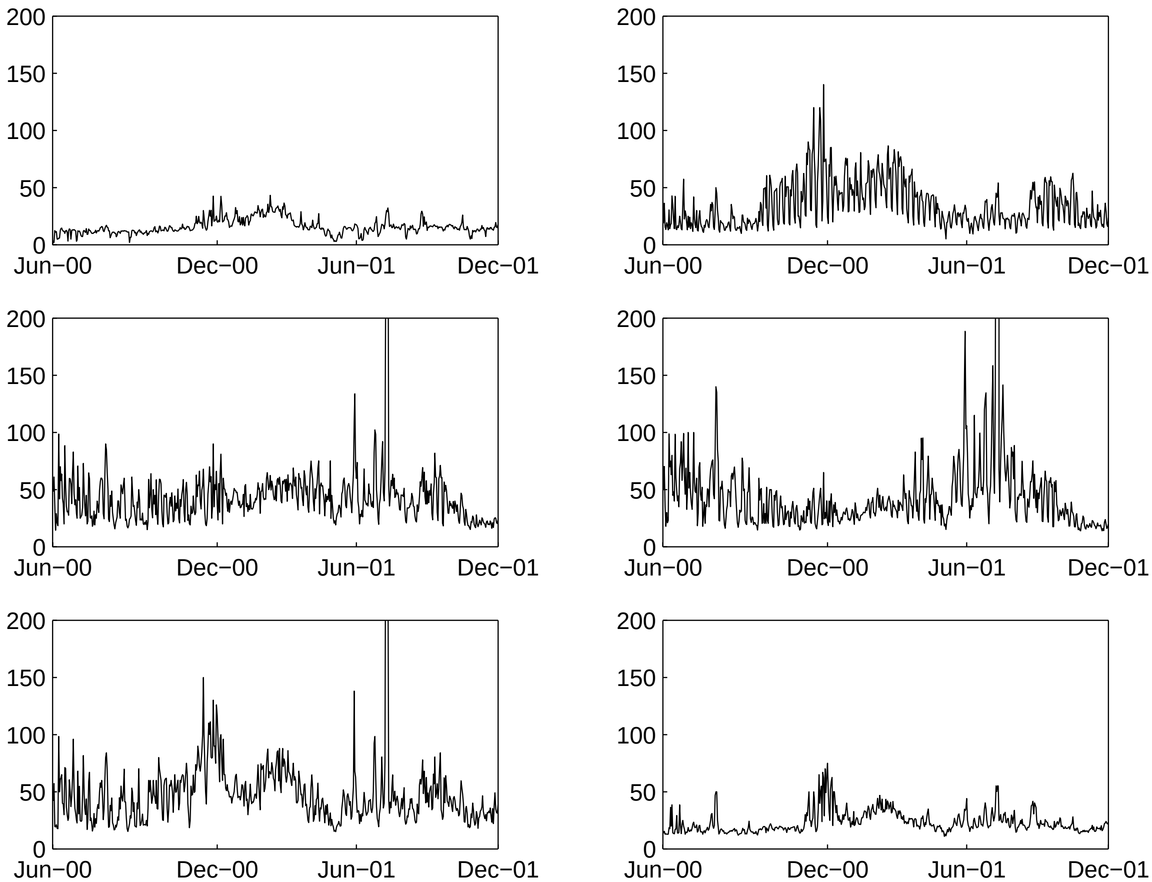

Fig. 2. This figure plots the time series of day-ahead electricity forward prices for selected hours. From left to right, the top panels plot the forward prices for 4 A.M. and 8 A.M.; the middle panels, for 12 Noon and 4 P.M.; the bottom panels, for 8 P.M. and 12 Midnight. Prices are in dollars per megawatt hour.

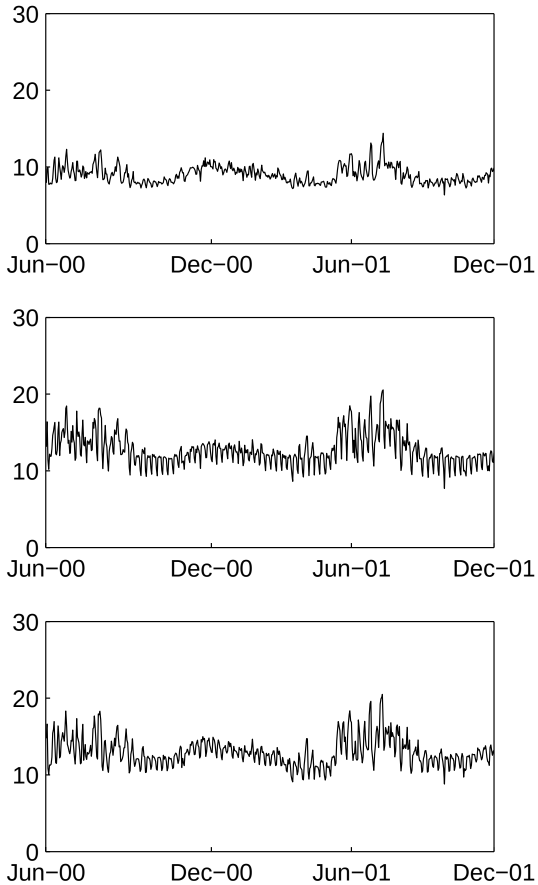

Fig. 3. This figure plots the time series of electricity demand for selected hours. From left to right, the top panels plot electricity demand for 4 A.M. and 8 A.M.; the middle panels, for 12 Noon and 4 P.M.; the bottom panels, for 8 P.M. and 12 Midnight. Electricity demand is expressed in gigawatt hours.

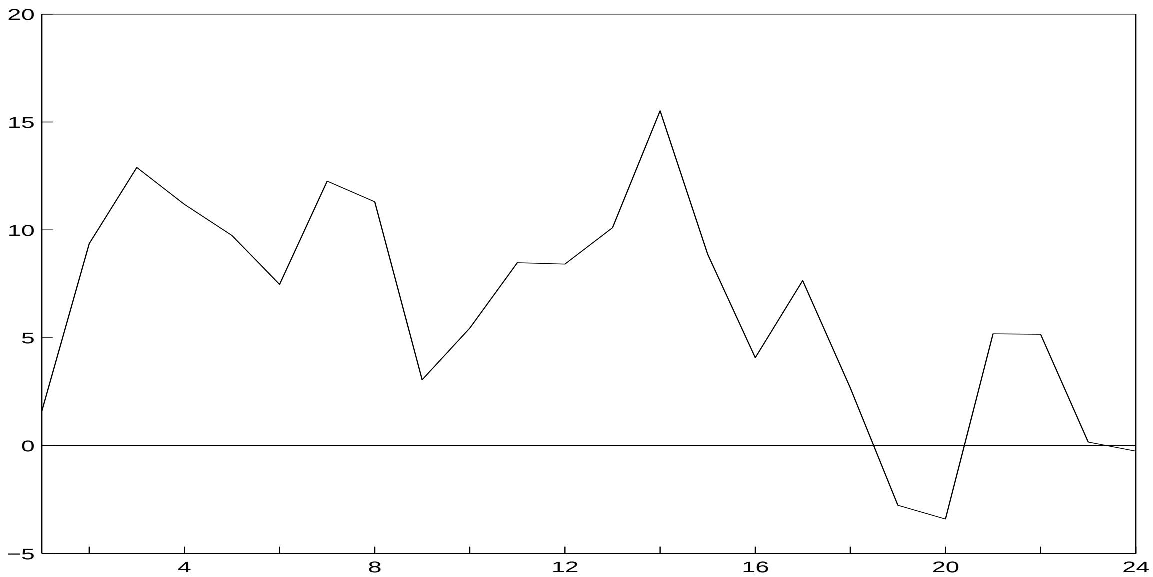

Fig. 4. This figure plots the average percentage forward premium for each of the 24 hours.

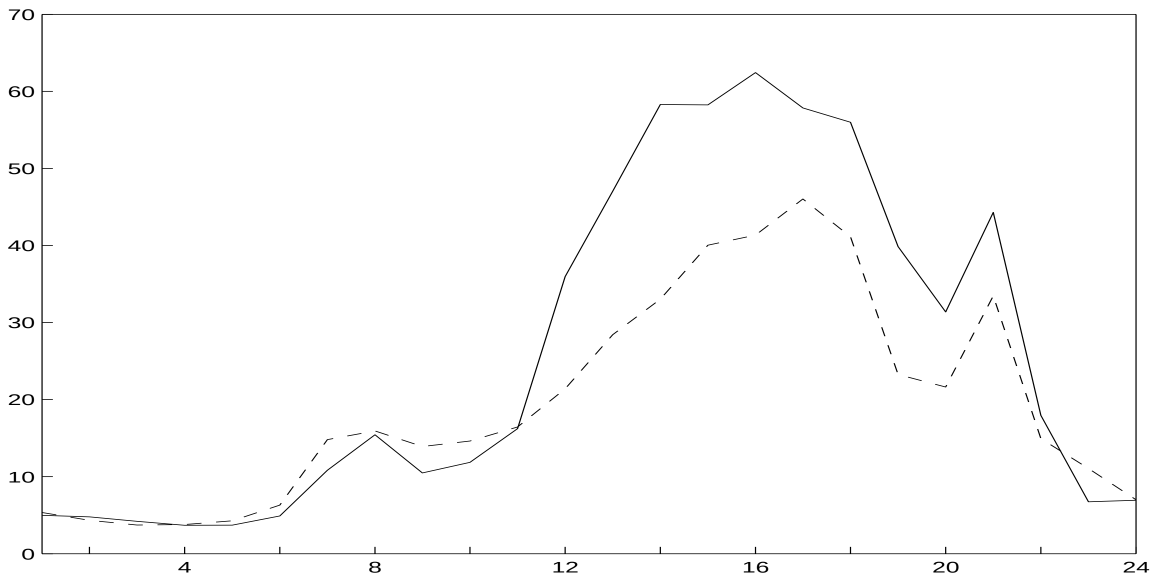

Fig. 5. This figure plots the standard deviations of daily changes in expected spot and forward prices for each of the 24 hours. The solid line is for expected spot prices. The dashed line is for forward prices. Standard deviations are expressed in dollars per megawatt hour.