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Electricity Forward Prices: A High-Frequency Empirical Analysis

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ABSTRACT

We conduct an empirical analysis of forward prices in the PJM electricity market 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 demand, spot prices, and total revenues. These results support the hypothesis that electricity forward prices in the Pennsylvania, New Jersey, and Maryland market are determined rationally by risk-averse economic agents.

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 focused initially 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 the 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

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[1] For example, see Cummins and Friedland (2002).

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 difference between the forward and expected spot prices) should represent compensation to financial market participants for bearing systematic risk. Finding evidence that premia in electricity forward prices are related to measures of risks faced by market participants would 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, and Maryland (PJM) electricity market for the period from June 2000 to November 2002. 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 an 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 there are significant electricity forward premia, but that these premia vary systematically through the day and can be both positive and negative. This contrasts with the implications of the classic hedging-pressure literature (Keynes (1930), Hicks (1939), Cootner (1960), and others), but is consistent with more recent equilibrium models such as Hirshleifer (1988, 1990), Routledge, Seppi, and Spatt (2001), and Bessembinder and Lemmon (2002). We find that forward premia are highest during the peak evening hours. For example, the average premium during 6 p.m. is \$5.41/MWh, representing more than 12% of the average spot price of electricity. This represents a huge premium for bearing spot price risk for one day.

In an important recent paper, Bessembinder and Lemmon (2002) present a general equilibrium model of electricity forward prices in a market where power producers and retailers face demand uncertainty. In their model, electricity forward premia are negatively related to price volatility, but positively related to price skewness. We test these empirical implications and find that they are both supported by the data. These results indicate that their model captures many of the key economic features determining prices in electricity spot and forward markets. The strong evidence for positive skewness in both the electricity spot and forward markets is also consistent with the empirical implications of the model presented in Routledge et al. (2001).

To understand better the properties of the premia embedded in electricity forward prices, we also examine whether they vary systematically through time in a way that mirrors changes in fundamental measures of risk. Specifically, we test whether these premia are related to the conditional volatilities of unexpected changes in electricity demand, spot prices, and total revenue. We find evidence that forward premia are positively related to all three of these risk measures. These results support the hypothesis of rational price setting in the PJM electricity markets and indicate the presence of time-varying forward premia.

As an additional test for the presence of time-varying 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 rationality in the PJM market.

This paper contributes to the rapidly growing literature on electricity contract prices. In addition to the recent work by Bessembinder and Lemmon (2002) and Routledge et al. (2001), other papers focusing on energy contracts include Gibson and Schwartz (1990), Amin, Ng, and Pirrong (1994), Jaillet, Ronn, and Tompaidis (1997), Kaminski (1997), Eydeland and Geman (1998), Pilipovic and Wengler (1998), Borenstein et al. (2001), Joskow and Kahn (2001), Kellerhals (2001), Borenstein, Bushnell, and Wolak (2002), Bushnell and Saravia (2002), 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), Bessembinder (1992), 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 I describes the PJM spot and day-ahead forward markets. Section II describes the data used in the study. Section III discusses the pricing of electricity forward contracts. Section IV examines the properties of forward premia. Section V examines whether forward premia are time-varying. Section VI presents the volatility tests for forward premia. Section VII summarizes the results and makes concluding remarks.

I. 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. Finally, we explain how the PJM spot and forward markets operate.

A. The PJM System

PJM Interconnection LLC 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 Gwh 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, DC. 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.

B. Market Participants

The massive scale of the PJM energy markets and the system's reputation for cost efficiency and reliability have helped to 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 functions. 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, 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 generally have 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, 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.

C. 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

[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.

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 locational marginal price is the lowest sum of the offer prices and associated congestion charges available to the marginal buyer. 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 prices averaged over a large portion of the PJM system's service area in the analysis. These locational issues may slightly increase the volatility of prices observed in the 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, 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 will likely 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 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 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

[3] Other empirical work on electricity prices includes Escribano et al. (2002) and Lucia and Schwartz (2002), who use the daily average of prices across all 24 hours. Borenstein et al. (2001) study the price convergence between day-ahead and real-time markets in California using data that averages prices across hours 1–6 and across hours 8–24. 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.

it would be possible to study using month-ahead contracts on daily averaged prices.[4]

II. 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 November 30, 2002. For each of the 913 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 I reports summary statistics for the electricity spot prices. Spot prices are quoted in dollars per megawatt hour ($/MW h). Figure 1 plots the time series of spot prices for a representative subset of hours. As shown in Table I, the average spot price varies throughout the day, ranging from a low of about $15 for the early morning hours to a high of about $49 for the peak late afternoon hours. Table I and Figure 1 also show that there is considerable time-series variation in the spot price, particularly during peak hours.[5] For example, the standard deviations for the spot prices exceed $70 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 $1,000, which is more than 20 times the mean value 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 et al. (2001). Note from Table I that the hourly spot prices display a fair amount of serial correlation across days, with first-order serial correlation coefficients ranging from 0.26 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. Finally, we note that there are also large seasonals in spot prices across months and from season to season. In particular, the highest spot

[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 for significant premia in month-ahead electricity forward contracts, they also point out the limitations inherent in having to rely on a small sample.

[5] Note that in a few instances, electricity prices can be zero or even slightly negative. This is an artifact of the nonstorability of electricity in conjunction with the adjustment costs of changing generating capacity quickly. We are grateful to the referee for this insight.

Table I
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. The expression 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 November 30, 2002 period. The overall serial correlation coefficient is the average of the hourly serial correlation coefficients.

Hour	Mean	Std. Deviation	Minimum	Median	Maximum	AR_1
1	18.70	8.59	0.00	16.38	69.42	0.55
2	17.49	8.67	0.00	15.46	71.28	0.56
3	15.92	8.03	−1.47	14.84	69.67	0.53
4	15.23	7.70	−2.42	14.42	70.41	0.53
5	16.03	7.63	−4.74	15.03	79.46	0.46
6	19.25	9.52	0.00	16.99	94.39	0.42
7	26.97	17.36	0.00	21.17	117.87	0.43
8	31.29	21.56	0.00	23.55	157.48	0.34
9	31.09	17.57	−1.92	25.31	151.90	0.26
10	35.24	18.94	−2.05	30.35	164.39	0.29
11	40.45	22.95	10.52	35.27	249.68	0.40
12	41.49	43.00	7.08	33.13	846.50	0.49
13	42.69	57.21	2.63	31.62	1005.53	0.51
14	47.22	69.92	7.94	33.10	1020.28	0.59
15	45.04	73.14	5.19	29.52	1019.97	0.59
16	43.81	76.43	7.80	27.25	1019.72	0.38
17	46.90	68.09	11.83	34.13	1019.74	0.48
18	48.99	57.95	6.13	38.95	1019.75	0.57
19	42.22	44.97	12.82	34.14	801.55	0.30
20	39.36	29.96	10.01	33.08	645.32	0.34
21	42.49	40.92	13.18	34.52	994.98	0.41
22	35.20	21.82	12.66	29.05	352.38	0.43
23	25.58	12.61	8.11	20.82	116.32	0.48
24	21.12	10.31	1.87	17.93	157.24	0.51
Overall	32.91	40.83	−4.74	23.04	1020.28	0.45

prices tend to be observed in the winter and summer months when demand is high. This is clearly seen from Figure 1. This seasonality pattern is consistent with the implications of Bessembinder and Lemmon (2002).

Table II presents summary statistics for the electricity forward prices. These forward prices are quoted in the same units as spot prices ($/MW h). Figure 2 plots the time series of forward rates for the same hours as shown in Figure 1. As can be seen, the properties of the electricity forward prices are similar in some ways to those of the spot prices. For example, the average forward prices are comparable in magnitude to the average spot prices given in Table II 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

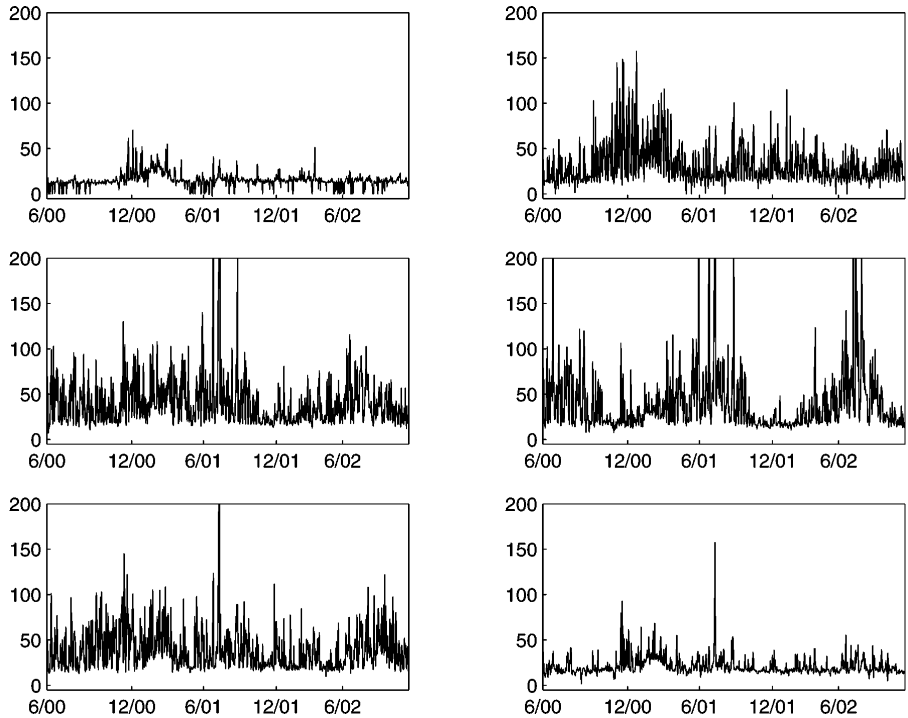

Figure 1. Time series of electricity spot prices for selected hours. From left to right, the top panels plot the spot prices for hours 4 and 8; the middle panels, for hours 12 and 16; and the bottom panels, for hours 20 and 24. Prices are in dollars per megawatt hour.

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 more serially correlated than the spot prices. The first-order serial correlation coefficients for the hourly forward prices range from 0.46 to 0.83.

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 megawatt hours) from PJM for the eastern hub. The load data is fairly smooth with a strong weekly seasonal. Demand during summer (June, July, and August) and winter (December, January, and February) also tends to be higher than during the other seasons. 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. Figure 3 graphs the average demand by hour of the day. 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

Table II

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. The expression 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 November 30, 2002 period. The overall serial correlation coefficient is the average of the hourly serial correlations coefficients.

Hour	Mean	Std. Deviation	Minimum	Median	Maximum	AR_1
1	19.32	6.96	5.00	17.29	50.01	0.76
2	16.85	5.91	0.00	15.48	45.20	0.79
3	15.57	5.76	0.00	14.69	43.98	0.79
4	15.17	5.94	0.00	14.34	43.22	0.83
5	15.78	6.33	0.00	14.94	46.39	0.80
6	19.02	7.99	0.10	17.39	50.01	0.73
7	27.70	16.10	1.00	22.50	150.00	0.68
8	32.03	17.25	1.15	27.37	140.01	0.68
9	33.53	15.06	11.01	30.00	130.01	0.66
10	36.46	15.19	13.45	33.46	125.00	0.63
11	39.49	18.04	14.95	35.71	198.10	0.65
12	40.59	24.49	14.47	36.00	390.93	0.71
13	40.77	31.42	14.68	35.31	545.46	0.70
14	42.91	39.16	13.75	35.21	646.81	0.73
15	43.76	48.57	13.30	34.00	818.54	0.75
16	44.53	50.66	13.87	33.28	859.05	0.75
17	47.35	49.81	15.03	36.19	779.38	0.68
18	51.82	42.25	15.02	44.04	599.22	0.65
19	47.63	30.25	14.91	40.94	450.01	0.75
20	44.80	26.16	15.06	39.86	416.27	0.73
21	43.24	26.76	15.10	38.56	498.01	0.46
22	35.94	16.98	15.00	32.07	185.90	0.69
23	27.69	11.90	12.68	23.99	112.86	0.67
24	22.01	8.92	0.00	18.82	74.96	0.75
Overall	33.50	28.86	0.00	27.36	859.05	0.71

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.

III. 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

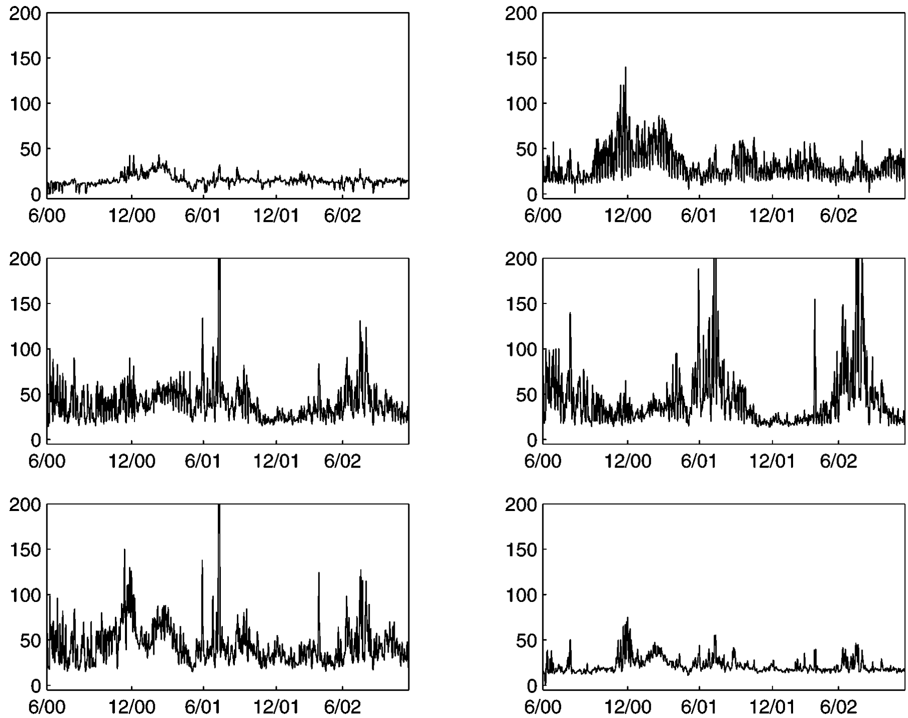

Figure 2. Time series of day-ahead electricity forward prices for selected hours. From left to right, the top panels plot the forward prices for hours 4 and 8; the middle panels, for hours 12 and 16; and the bottom panels, for hours 20 and 24. Prices are in dollars per megawatt hour.

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 essentially nonstorable, 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), Routledge et al. (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 forward price and the expected spot price. Some recent authors such as French (1986) and Fama and French (1987) focus on percentage forward premia. In either case,

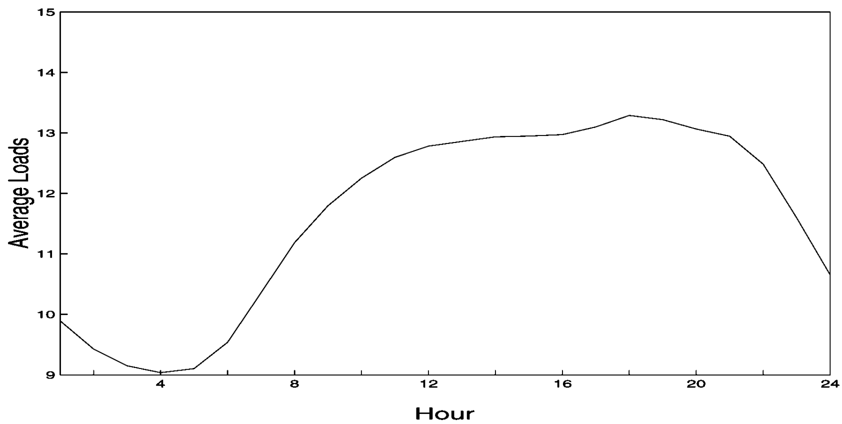

Figure 3. Average electricity demand. This figure plots the average load in gigawatt hours for each of the 24 hours.

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 and/or demand risk for the underlying commodity. The classical literature (Keynes, Hicks, and others), suggests that expected spot prices should typically be higher than forward prices (implying a negative premium), reflecting systematic hedging-pressure effects. More recently, however, Hirshleifer (1990) provides examples showing that the equilibrium forward premium need not be strictly negative. Similarly, in the general equilibrium model of electricity spot and forward markets presented by Bessembinder and Lemmon, the forward premium is negative when expected price skewness is small, but can be positive when expected price skewness is large. 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.[7] 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. To fix notation, let F_{it} denote 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 forward premium can now be defined as

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

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

[7] Alternatively, one can argue that electricity is a fundamental component of a representative agent's consumption basket. Thus, electricity price risk represents a systematic risk which should be priced in a consumption-based asset pricing model. For example, see Breeden (1980, 1984).

IV. Empirical Tests

To examine whether there are forward premia, we take the sample mean of the expression in equation (1) for each hour and test whether these means are significantly different from zero:

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

where the expectation is unconditional. Table III 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 et al. (2001) that electricity prices should display

Table III

Unconditional Tests for the Presence of Forward Premia in Electricity Forward Prices

This table presents the mean realized forward premium for each of the 24 day-ahead electricity forward contracts along with their t-statistics, where the realized forward premium is defined as $F_{i,t} - S_{i,t+1}$. The t-statistics are based on autocorrelation and heteroskedasticity consistent estimates of the variances. Also reported are the median estimates of the realized forward premia.

Hour	Mean	t-Statistic	Median
1	0.62	2.97	0.69
2	−0.64	−2.95	−0.13
3	−0.36	−2.06	−0.21
4	−0.06	−0.31	−0.10
5	−0.25	−1.37	−0.26
6	−0.23	−0.79	−0.18
7	0.73	1.30	0.67
8	0.74	1.42	1.66
9	2.44	4.24	2.43
10	1.22	2.21	2.84
11	−0.96	−1.60	1.59
12	−0.90	−0.85	2.51
13	−1.92	−1.33	2.13
14	−4.31	−2.38	1.28
15	−1.27	−0.77	2.35
16	0.72	0.38	3.25
17	0.45	0.25	2.18
18	2.83	1.93	4.60
19	5.41	4.47	6.18
20	5.44	6.02	5.91
21	0.75	0.53	2.75
22	0.74	1.18	1.70
23	2.10	4.45	2.10
24	0.89	2.28	0.98
Overall	0.59	1.23	1.20

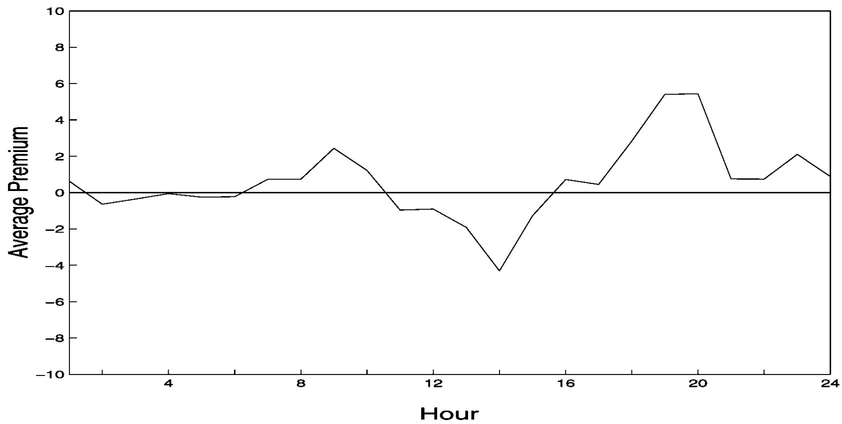

Figure 4. Average forward premia. This figure plots the average forward premium for each of the 24 hours.

conditional heteroskedasticity. Figure 4 plots the mean values of the forward premia.

As shown, the overall mean of the forward premia is 59 cents, but is not statistically significant. Despite this, there is clear evidence of significant forward premia when one looks at the results for the individual hours. In particular, the mean forward premium is statistically significant for 10 of the 24 hours. Bonferroni tests for the joint significance of all 24 means strongly reject the null hypothesis that unconditional forward premia are all zero. Interestingly, however, the mean forward premia vary significantly across hours in both their magnitude and sign. For example, the mean forward premium is negative for 10 of the hours and positive for 14 of the hours. The mean forward premia range from a low of −$4.31 during 1 p.m. to a high of $5.44 during 7 p.m. Thus, forward premia in the electricity market may experience significant variation over horizons measured in minutes or hours.

The individual mean forward premia are often very large. For example, the mean forward premia for 6 p.m. and 7 p.m. are $5.41 and $5.44, respectively. In terms of the average spot prices for these hours, these premia represent percentage premia of 12.8 and 13.8, respectively. These are extremely large premia, given that the forward contract only has a one-day horizon. This is consistent with Bessembinder and Lemmon (2002), who argue that large risk premia may reflect the lack of risk-sharing in electricity markets and that large risks are borne by a few companies.

In an important recent paper, Bessembinder and Lemmon (2002) present a general equilibrium model of electricity prices that incorporates many realistic economic features of these markets. In particular, competitive power producers face marginal production costs that may increase steeply with output. Aggregate power demand is exogenous and stochastic, reflecting the reality that factors such as temperature and weather create significant demand risk for producers and retailers in the electricity market. Although total system retail

Table IV
Regression of Average Forward Premium on the Variance and Skewness of Spot Prices

This table reports the results from regressing the average forward premia for each of the 24 hours on the sample variance (divided by 100) and skewness measures for the corresponding hours.

$$\text{Ave.}\,FP_i = a + b\,\text{Var}_i + c\,\text{Skew}_i + \epsilon_i$$

	a	b	c	t_a	t_b	t_c	R^2	N
All hours	0.13	−0.07	0.27	0.19	−2.29	1.95	20.39	24

demand is the fundamental economic state variable in their model, Bessembinder and Lemmon show that the forward premium can be expressed in reduced form as a simple linear combination of the variance and skewness of the endogenous spot price. Furthermore, they demonstrate that the forward premium is negatively related to the variance of the spot price, but positively related to the skewness of the spot price. One of the key insights of their model is that the risk of price spikes arising from unanticipated sudden increases in power demand can have significant effects on the size and even the sign of the forward premium. Tables II and III of their paper provide evidence supporting their model in that forward premia are highest in winter and summer when the weather is the most extreme. Our results in Table III parallel the Bessembinder and Lemmon findings in that we find the highest premia in the late afternoon and early evening hours when demand is at its peak and most likely to approach capacity and create potential spikes in spot prices.

The estimates of the forward premia across hours allow us to test these empirical implications of the Bessembinder and Lemmon (2002) model in a very simple but direct way. Specifically, we regress the mean forward premia on the variance and skewness measures for the spot price during the sample period for each of the 24 hours. The results from this cross-sectional regression are shown in Table IV. As indicated, both implications of the Bessembinder and Lemmon model are supported by the data. The variance of the spot price is negatively related to the forward premium with a t-statistic of -2.29. The skewness of the spot price is positively related to the forward premium and has a t-statistic of 1.95. The R^2 for the regression is 20%. These results imply that the convexity of the power production function and its impact on the skewness of prices as modeled by Bessembinder and Lemmon are key elements in understanding the relation between electricity spot and forward prices. These convexity features are also consistent with Routledge et al. (2001) who argue that the "downstream" nature of electricity can induce option-like effects in electricity spot prices.

V. Time Variation in Forward Premia

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

A. Testing for Time Variation

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

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

where $\epsilon_{i,t+1}$ represents the unexpected component of the realized forward premium and is orthogonal to information at time t. Thus, from equation (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 forward premium on risk factors in the information set at time t. Finding that these ex ante risk measures have explanatory power for the ex post realization would indicate that there are time-varying forward premia in electricity forward prices.

B. The Risk Measures

Most asset pricing models have in common the feature that risk premia are directly related to measures of risk, typically expressed in terms of second moments. Measures of risk that appear frequently throughout both the classical and more recent literature on the equilibrium pricing of forward contracts on nonstorable or nonmarketable commodities are price, quantity, and revenue uncertainty. In some sense, these risks are fundamental to any general equilibrium model because of the market clearing condition.

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 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.[8] The GARCH estimate of the conditional variance of unexpected price changes (where only information known prior to 4 p.m. is

[8] 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 than on unexpected price changes.

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 each 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 to 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 definition is reversed during winter). The second is the absolute deviation of the average temperature during a day from a "comfortable" benchmark of 68°C. The third measures the difference between the daily maximum wind speed during winter and 11.5 miles per hour, and can be viewed as a measure of winter wind chill. 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 V reports the R^2's for the VARs forecasting price changes. As shown, much of the spot price change from day t to $t + 1$ is predictable.

To provide measures of demand and revenue 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, as well as the total revenue (price times quantity) for the system. The R^2's for the VAR forecasts of the electricity loads and total revenues are also reported in Table V. Subtracting the expected values from realized values gives a time series of innovations. We again fit a GARCH(1,1) model to these innovations to obtain estimates of the conditional volatilities.[9] 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 uncertainty. We denote the GARCH estimate of the conditional volatility of unexpected changes in load by VL_{it} and in revenue by VR_{it}.

C. Empirical Results

Given these ex ante risk measures, we estimate the regression,

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

for each of the 24 hours as a system using the seemingly unrelated regression technique of Zellner to exploit the intraday overlapping nature of the premia. We also estimate the regression using the entire pooled data set (in this system, the coefficients b, c, and d are the same across i). The estimation results are reported in Table VI.

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

Table V

The Adjusted 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 $S_{i,t+1}$, the load $L_{i,t+1}$, and total revenue $R_{i,t+1} = S_{i,t+1}L_{i,t+1}$, where $Y_{i,t+1} = [S_{i,t+1}, L_{i,t+1}, R_{i,t+1}]'$, include dummy variables D_j for month and weekend/holiday, the 24 hourly spot prices and loads for the 24-hour period immediately preceding the 4 p.m. forward market settlement time, and the three weather variables W_j described in the paper

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

Hour	Spot Price VAR R^2	Load VAR R^2	Revenue VAR R^2
1	52.17	93.73	62.71
2	52.28	92.86	60.25
3	50.83	87.63	58.24
4	51.29	91.10	57.22
5	46.96	90.65	52.64
6	44.51	90.44	51.59
7	51.68	91.26	53.79
8	46.50	92.43	49.65
9	30.89	91.85	39.80
10	33.18	90.84	45.17
11	42.38	90.03	54.49
12	53.93	89.44	59.85
13	56.48	88.76	62.01
14	58.05	88.40	61.48
15	48.57	87.96	51.31
16	42.09	87.23	44.34
17	47.96	85.82	50.18
18	58.24	84.13	62.67
19	38.13	82.06	54.06
20	50.11	80.17	59.51
21	56.04	80.13	62.08
22	39.48	80.90	52.79
23	32.85	80.42	43.85
24	38.63	80.10	50.73

Focusing first on the results for the entire data set, Table VI shows that all three of the risk measures are statistically significant; load risk and price risk are significant at the 10% level, while revenue risk is significant at the 1% level. The coefficient for load or demand uncertainty is positive, indicating that the forward premium is an increasing function of this risk measure. The coefficient for the price uncertainty measure is also positive. Finally, the coefficient for revenue risk is positive, which suggests that market participants consider their overall financial risk in making hedging decisions and determining equilibrium prices. This evidence that forward premia vary systematically with price, demand, and revenue uncertainty supports the hypothesis that electricity prices in the PJM market respond to fundamental economic risks.

Table VI

Results from Regressions of Realized Forward Premia on Economic Risk Measures

This table reports the results from hourly time-series and pooled time-series cross-sectional regressions of realized forward premia on GARCH(1,1) estimates of the conditional volatilities of unexpected load changes VL_t, spot price changes VS_t, and revenue changes VR_t. The regressions are estimated as a system using the seemingly unrelated regression procedure. The pooled results are estimated by imposing the restriction that the b, c, and d coefficients are the same across all hours. The p-values reported are based on the Wald statistic for the hypothesis that the b, c, and d coefficients for the indicated regression are zero.

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

Hour	a	b	c	d	t_a	t_b	t_c	t_d	p-Value
1	0.47	−0.12	−0.98	89.80	0.60	−0.06	−3.92	3.95	0.001
2	−0.39	1.72	0.00	−13.90	−0.56	1.08	−0.01	−0.52	0.160
3	−0.19	1.23	0.03	−16.30	−0.18	0.51	0.10	−0.60	0.227
4	−0.35	0.79	0.08	−7.25	−0.48	0.49	0.23	−0.24	0.964
5	−0.62	−1.30	−0.26	42.30	−0.71	−0.63	−0.57	1.08	0.003
6	−0.42	−4.42	0.30	−2.51	−0.31	−1.30	3.76	−0.42	0.000
7	−8.91	11.29	0.84	−32.30	−2.28	1.25	1.64	−0.80	0.000
8	−3.53	3.61	0.13	4.32	−0.92	0.44	0.26	0.11	0.159
9	−6.62	−0.21	0.98	−23.40	−2.00	−0.04	6.00	−2.88	0.000
10	−26.73	−5.22	−0.03	151.95	−3.13	−1.21	−0.18	3.53	0.002
11	−1.42	−0.09	−0.21	16.20	−0.16	−0.03	−0.28	0.84	0.306
12	−1.64	3.14	−0.12	3.57	−0.53	0.74	−0.63	0.36	0.606
13	−2.03	0.76	0.00	−0.77	−0.50	0.16	0.14	−0.31	0.989
14	2.80	−1.05	0.08	−7.05	0.37	−0.20	1.43	−1.19	0.552
15	11.43	−4.68	0.56	−24.40	2.11	−0.92	5.67	−4.92	0.000
16	0.28	−2.21	−0.14	9.41	0.05	−0.36	−0.52	0.71	0.268
17	−9.05	5.19	0.74	−30.10	−1.64	1.00	1.05	−0.91	0.145
18	−9.29	9.35	−0.00	5.90	−2.26	2.32	−0.01	2.80	0.001
19	−7.15	6.74	−0.21	26.90	−1.54	1.79	−0.71	1.12	0.048
20	0.69	0.38	0.29	−4.69	0.16	0.09	2.07	−0.77	0.188
21	−2.31	2.78	0.60	−32.90	−0.55	0.88	1.55	−1.99	0.062
22	0.27	2.87	−0.49	25.70	0.11	1.48	−2.00	2.07	0.004
23	−2.64	6.44	−0.18	14.20	−1.45	5.15	−1.17	1.24	0.000
24	−2.30	−0.07	0.53	−7.20	−2.41	−0.06	2.27	−0.40	0.000
Pooled	–	1.11	0.03	2.87	–	1.65	1.75	2.99	0.000

The individual hourly regressions show that there is also significant variation across hours in the relation between forward premia and economic risk measures. The volatility of unexpected changes in demand is significant for 2 of the 24 hours; the volatility of unexpected changes in the spot price is significant for 7 of the 24 hours; and the volatility of unexpected changes in revenue is significant for 7 of the 24 hours. To examine whether there is a significant relation between the forward premia and the risk measures for the individual regressions, we test the hypothesis that $b = c = d = 0$ for each equation using a standard Wald test. The p-values for these tests provide evidence for a significant relation to the risk measures for 12 of the 24 hours.

At first glance, the positive relation between price and demand volatility in Table VI may appear inconsistent with the implications of Bessembinder and Lemmon (2002). It is important to observe, however, that price and demand uncertainty are directly linked in the Bessembinder and Lemmon model because the endogenous equilibrium price is a function of the exogenous aggregate demand. Thus, our partial regression coefficients, which hold fixed the other endogenous or exogenous variables, cannot be directly mapped into the comparative statics results given by Bessembinder and Lemmon. Thus, this regression does not provide evidence against their model. In fact, finding that these risks are embedded within forward premia provides support for the equilibrium approach used by Hirshleifer (1988, 1990), Routledge et al. (2001), and Bessembinder and Lemmon in modeling forward premia.

VI. 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, equation (1) implies that

$$F_{it} = E_t[S_{i,t+1}]. \tag{5}$$

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 equation (5) 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 by the VAR model described in the previous section. To implement this test, Table VII 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 Figure 5.

As shown in Table VII and Figure 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 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, the highest average prices, and the highest probability of observing price spikes. Thus, it makes intuitive sense that the 12 noon to 9 p.m. period might represent the period when PJM market

Table VII

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	4.81	4.79	0.02	1.00
2	4.74	3.79	0.95	1.25
3	4.16	3.69	0.47	1.13
4	3.91	3.45	0.46	1.13
5	3.69	3.98	−0.29	0.93
6	5.08	5.82	−0.74	0.87
7	10.70	12.89	−2.19	0.83
8	13.48	13.86	−0.38	0.97
9	9.31	12.35	−3.04	0.75
10	10.86	13.15	−2.29	0.83
11	14.35	15.00	−0.65	0.96
12	27.85	18.81	9.04	1.48
13	37.25	24.42	12.83	1.53
14	46.86	28.85	18.01	1.62
15	46.47	34.27	12.20	1.36
16	49.88	35.89	13.99	1.39
17	46.50	39.63	6.87	1.17
18	44.35	35.59	8.76	1.25
19	30.52	21.32	9.20	1.43
20	23.87	19.18	4.69	1.24
21	33.26	27.84	5.42	1.19
22	14.27	13.40	0.87	1.06
23	6.33	9.67	−3.34	0.65
24	5.95	6.31	−0.36	0.94
Average	20.77	17.00	3.77	1.12
t-Statistic for average difference			2.94	

participants face the greatest economic risks. 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 2.94. 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 than 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

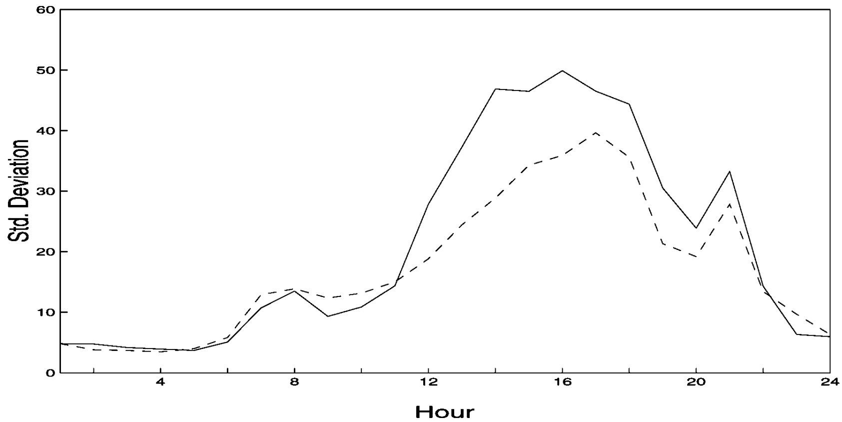

Figure 5. Standard deviations of changes in prices. This figure plots the standard deviation of daily changes in expected spot and forward prices for each of the 24 hours. The solid line is for expected spot prices. The dashed line is for forward prices. Standard deviations are expressed in dollars per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

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 VII.

VII. 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 PJM market participants.

We find that there are significant forward premia in electricity forward prices. On average, these premia are positive, although there is significant variation in these premia throughout the day. Although positive premia are not consistent with the classical hedging pressure literature (Keynes (1930), Hicks (1939), Cootner (1960), and others), they are consistent with more recent models such as Hirshleifer (1988, 1990) and Bessembinder and Lemmon (2002). The size of the average premia varies throughout the day, ranging from −\$4.31 to \$5.44. We find that forward premia are negatively related to price volatility and positively related to price skewness. This provides strong support for the model of electricity forward prices presented by Bessembinder and Lemmon.

We further examine whether the forward premia reflect compensation for risk-taking by regressing forward premia on measures of price, quantity, and revenue risk. We find that each of these risk measures plays a significant role in explaining the forward premium. Furthermore, these results demonstrate that electricity forward premia vary significantly through time. 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. These results provide additional empirical support for the existence of time-varying forward premia.

Finally, despite the documented evidence in support of rational price setting in the PJM market, caution should be exercised in generalizing the results to other markets. For example, recent papers by Chandley, Harvey, and Hogan (2000), Blumstein, Friedman, and Green (2002), and others document that the California electricity market has a very different structure from the PJM market. In fact, some have argued that the California market design is more vulnerable to abuses than the PJM market. Thus, it is important to recognize that the scope of our study is limited to the PJM market.

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