Energy Policy 107 (2017) 109–118

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Market efficiency assessment under dual pricing rule for the Turkish wholesale electricity market

Goksel Asan[a,*], Kamil Tasaltin[b,c]

[a] Istinye University, Department of Economics, Topkapı Kampüsü, Maltepe Mah., Edirne Çırpıcı Yolu, No. 9 Zeytinburnu, 34010 İstanbul, Turkey
[b] Deloitte LLP, Economic Consulting, Athene Place, 66 Shoe Lane, London EC4A 3BQ, UK
[c] Istanbul Bilgi University, Turkey

ARTICLE INFO

Keywords:
Electricity
Market structure
Market efficiency

ABSTRACT

This study analyses the price dynamics of day-ahead and real-time electricity prices following the implementation of dual-pricing legislation in Turkey, to understand the legislation's impact on arbitrage opportunities and market efficiency. The convergence of prices between the day-ahead forward and the real-time markets analysed in order to determine whether persistent price differences between the two markets exist. Arbitrage opportunities exist if there is a persistent difference between prices in the day-ahead forward and real-time market. Markets are considered to be efficient if it is not possible for market participants to earn an excess profit through exploitation of price differences. Furthermore, we examined how the ex-post risk premium changes over time using rolling estimations and find that after the implementation of dual pricing, the risk premium increased significantly for day and peak hours where the demand is relatively higher compared to night hours. As market participants have more experience regarding the dynamics of the market, the difference between real-time and day-ahead forward prices converges to zero since the dual-pricing regime enforce market participants to forecast accurately by punishing the forecast error.

1. Introduction

The Turkish electricity market has been through a process of liberalization over the last couple of decades. From 2006, the rules of the free market were introduced which allowed for the purchase and sale of electricity from a day-ahead market on an hourly basis. This provides market participants an opportunity to hedge their positions against the real-time price fluctuations by taking positions in the day-ahead forward market.

Having a liberal free market raises questions regarding the efficiency of the market structure as well as the relationship between electricity spot price and day-ahead forward prices. Markets are considered to be efficient if it is not possible to achieve a consistent excess return over time compared to the average market return. In an efficient market, participants are not able to earn an excess profit by exploiting price differences. It is important to note that traditional market efficiency measures assumes commodities are storable. However electricity is different to other common commodities due to its non-storable nature. If the trading commodity is storable, then a market player can purchase the good today, store it for a period of time and sell in the future – expecting to gain profit through price differences. However, electricity traded on present day is a different good compared to that tomorrow as storing the electricity is not economically viable. Bessembinder and Lemmon (2002) states that since electricity cannot be economically stored and the spot power prices are volatile, the standard no-arbitrage-based approaches are not applicable for modelling forward prices. No-arbitrage-based approaches assumes an arbitrageur to hold the asset until the contract expiration date while taking a position in the underlying asset.

However, in an electricity market arbitrage opportunity exists for the market participants if a persistent price difference exists between day-ahead forward prices and real-time prices.[1] In theory, strategies for market participants to gain excess revenue by exploiting the price differences should make the real-time and day-ahead market prices close to each other under the assumption of no transaction costs and risk-neutral market participants.

In this study, price convergence between the day-ahead and the real-time markets is analysed in order to determine whether persistent price differences between the two markets exist. The electricity wholesale market is considered to be efficient if there are no arbitrage

* Corresponding author.
E-mail addresses: gasan@istinye.edu.tr (G. Asan), ktasaltin@yahoo.com (K. Tasaltin).

[1] The available arbitrage opportunities have been summarized for both suppliers and generators in Section 2. Please also see Quan and Michaels (2001) and Jha and Wolak (2013) for further discussion on available arbitrage opportunities between day-ahead forward and real-time markets.

http://dx.doi.org/10.1016/j.enpol.2017.04.024
Received 4 October 2016; Received in revised form 7 March 2017; Accepted 9 April 2017

opportunities as a result of trading strategies between real-time and day-ahead markets. If there is no transaction cost the expected value of the difference between day-ahead (current forward price) and real-time prices (spot price) should be zero.

Through the liberalization process of Turkish electricity market, the hourly balancing and settlement system was set in place in December 2009 to allow market participants to buy and sell electricity in day-ahead and spot market on an hourly basis. On December 2011, the dual-pricing system rule for imbalances in electricity market was implemented in Turkey, (3 November 2011, legislation No: 28104). Implementation of dual pricing rule for imbalances changed the price dynamics of electricity. Under the dual pricing rule, electricity buyers and sellers in the real-time market are charged based on the price that is least favourable to the market participant. The difference between the actual consumption or generation and that which was purchased through the day-ahead market (simply imbalances) is charged based on the price that is least favourable to the market participant. In other words, buyers have to pay the greater of day-ahead or real-time prices, while sellers receive the lesser.

The main objective of the dual pricing rule is to discourage participants seeking arbitrage opportunities by making it unattractive for them to make false bids or offers since these could harm system security as well as enforcing market participants to bid their actual forecast using the available information at the time. False bids or offers could harm short-term system security, for example by implying greater capacity in the market than actually exists. This study finds that while dual pricing rule increases the short-term system security, it also creates a persistent difference between day-ahead and spot electricity prices (forward risk premium[2]) which implies a market inefficiency, since it limits market participants to exploit the arbitrage opportunities that exist.[3] However, in the long run the risk premium in the market reduces. Newly introduced wholesale power markets could result in the observed forward prices differing from the pricing structure that will be observed in a long-run equilibrium, reflecting the inexperience of market participants. The results show that, although there is an increase in risk premium after the implementation of dual-pricing, it decreases over time. This indicates that market efficiency increases as the market becomes more mature.

Due to the non-storable nature of electricity, it was decided not to use familiar no-arbitrage-based methods to examine the persistent price differences in Turkish electricity market in this paper. Instead, the price convergence between the day-ahead and the real-time market is analysed similar to Longstaff and Wang (2004), Borenstein et al. (2001) and Arciniegas et al. (2003) to understand the presence of persistent price differences in electricity forward prices.

There are various market efficiency assessment studies in the literature. Borenstein et al. (2001) examine the price convergence in the California wholesale electricity market from the deregulation of the market in April 1998 to November 2000. Their hypothesis is that profit-maximizing traders exploit price differences between the day-ahead market and the real-time market that converges the prices of the two markets. The study concludes that the prices in the day-ahead market and real-time market converge as the market become more mature. Extending Borenstein et al. (2001) study, Arciniegas et al. (2003) analyses the doubts about the benefits of energy deregulation due to California's energy crisis in 2000 by assessing the level of efficiency reached by the electricity markets in California, New York, and PJM and compares the degree of efficiency across markets (forward vs. real-time) and across time. In addition to comparing the efficiency levels of electricity markets, they also conclude that as markets become more mature over time, their efficiency levels go up.

Jha and Wolak (2013) evaluate the market efficiency of California's wholesale electricity market after the implementation of virtual bidding. In their study, they estimate the cost of trading in the market by using the day-ahead forward and real-time spot locational marginal prices and concluded that purely financial forward market trading can improve the operating efficiency of short-term commodity markets. Longstaff and Wang (2004) conduct an empirical analysis of hourly spot and day-ahead forward prices in the PJM electricity market and find that there are significant risk premia in electricity forward prices related to volatility of unexpected changes in demand, spot prices, and total revenues. De Vany and Wall (1999) analyse the market integration of 11 regional markets in the western United States during 1994–1996 by using cointegration analysis and test the peak and off-peak electricity spot prices for evidence of market integration. The results of their study show that western US wholesale power markets were efficient and stable.

To the best of our knowledge, the only study on the impact of dual pricing rule is that conducted Boogerta and Dupont (2005) which analyses the effect of dual-pricing implemented by Dutch regulator to prevent trading across day-ahead market and real-time markets in the Netherlands through studying the ex-post profitability of trading strategies. Their results show that under dual-pricing these strategies are rarely positive and implementing a profitable trading strategy between the day-ahead and imbalance markets is not possible under dual-pricing.

This paper contributes to the literature on electricity prices by examining the existence of forward premium (persistent price differences between day-ahead and real-time electricity prices) after the implementation of dual pricing rule in Turkey and concludes that although in the short-run the markets could be inefficient due to the change in pricing rules, the markets become efficient as the markets become more mature.

The sections of this paper are as follows. In the first section, we provide an overview of the Turkish electricity market and explain how dual pricing for imbalances effects the arbitrage opportunities (through an explanation of the strategies of buyer and sellers in Turkish electricity market). In the second part of this paper, the market efficiency framework is explained. The third part explains the data used in this analysis. The fourth section gives the empirical evidence on risk premium in the Turkish electricity market. In the final section of this paper, we provide the output of rolling estimation of risk premium in day-ahead and explain how market efficiency changes over time as the market becomes more mature.

2. Turkish electricity market overview

The Turkish electricity market has been on a liberalization process over the last couple of decades. Before 1984, the electricity market was controlled by the Turkish Electricity Authority (TEK), a vertically integrated state-owned enterprise. Since then, the sector has undergone significant restructuring via market liberalization. The monopoly power of Turkish Electricity Authority was first removed in 1984 by allowing for privately owned generation companies. Starting from 1994, the vertically integrated value chain of Turkish Electricity Authority has been separated into generation, transmission, distribution and sales activities. This has been undertaken to lay the foundation of privatization in the electricity sector and pave the way for the creation of a liberalized competitive market.

In 1994, Turkish Electricity Authority was split into two companies; Turkish Electricity Distribution Company (TEDAS) and Turkish Electricity Generation and Transmission Company (TEAS). This

[2] In this study, forward risk premium (or simply forward premium) defined as difference between day-ahead and spot electricity prices however the terms risk premium, forward premium, forward risk premium and market price of risk are not uniquely defined in the literature. Please see Weron and Zator (2014) for further discussions.

[3] Based on our best knowledge there are no other economic and/or political factors that have led to the increase in the premium after the implementation of the dual pricing apart from the launch of intra-day market. Since, intra-day market have started its operations as of 1st July 2015 after 3.5 years from implementation of dual-pricing rule, it is not relevant within the scope of this analysis.

change led to the formation of 4 companies and 21 regional distribution & supply companies.

TEAS was restructured under Public Generation Company (EUAS), Public Transmission Company (TEIAS) and Public Wholesale Company (TETAS). A change which saw generation, transmission, wholesale and distribution & supply activities separated. TEDAS has been separated into 21 regional companies, which had been privatized later on. Furthermore, each distribution and retail company in each region has been unbundled under the new legislation as of the beginning of 2013. The distribution company in the region is in charge of network operations and the incumbent supplier (retailer) in the region is in charge of customer operations. Although the privatization of state-owned generation plants has begun, 27.3% (in 2013) of total electricity is still generated by stated owned power plants (TEIAS, 2014).

On 3 March 2001, the Electricity Market Law No. 4628 was enacted to ensure the delivery of sufficient, good quality, low cost and environment-friendly electricity to consumers. In order to achieve this objective, the Law targeted the development of a financially sound and well-functioning electricity market operating in a competitive environment under provisions of civil law. Enactment of this law is regarded as a critical milestone of the liberalization process. With the assignment of EMRA as the regulatory authority, the foundations of a free electricity market were laid.

From November 2004, the rules of the free market were introduced through the establishment of the Electricity Market Balancing and Settlement Regulation (BSR). The Balancing and Settlement mechanism went into operation on August 1, 2006 in MFSC (Market Financial Settlement Centre - PMUM in Turkish) under the corporate structure of TEIAS and has been producing the reference price for the market in a competitive way that reflects the supply-demand equilibrium.

Since the introduction of the Balancing and Settlement mechanism, the Turkish electricity market structure has been constantly developing and has seen changes reflecting greater complexity. The regulation was designed to optimize generation activities in Turkey through a day-ahead system, which was real-time balancing, making it more secure and easier to manage. Day-ahead planning was initially established as a temporary mechanism, making planning obligatory for all participants, though the final aim was to establish a day-ahead market.

From 2006–2009, the settlement was performed for three time periods, day (06.00–17.00), peak (17.00–22.00), and night (22.00–06.00). The balancing and settlement system was then updated in December 2009 to allow for hourly planning.

During the day-ahead planning phase, the National Load Dispatch Centre was responsible for estimating and announcing the following day's demand forecast. The price elasticity of demand was perfectly inelastic. For each generation asset, the generators would submit their hourly bids for the next day and MFSC would then prepare the following day's generation schedule so that the supply of electricity would be equal to forecasted demand.

Real-time generation would be based on the generation plan set on day-ahead planning. In real-time, where the supply of electricity is not equal to demand, the system operator (MFSC) would balance the system based on information previously provided by participating generators. The generators would have provided a minimum price at which they are willing to provide more electricity to the system as well as a ceiling on the price at which they are willing to provide less. Therefore the system would be in balance and a system marginal price, the real-time price, would be set. Through real-time balancing, demand for electricity will be fulfilled by generated electricity. The system marginal price would be set to be sure that the system is always in balance and secure.

In December 2011, the day-ahead market was introduced. The main difference between day-ahead planning and day-ahead market is that participation in the day-ahead market is not obligatory for all market participants, unlike in day-ahead planning. Further, the day-ahead market allows firms to bid on a portfolio-wide basis, rather than a unit basis, as was the case with day-ahead planning.

In December 2011, in addition to the introduction of the day-ahead market, the dual-pricing system for imbalances was implemented (3 November 2011, legislation No: 28104). Under dual pricing rule, the difference between the actual consumption or generation and the consumption or generation that was purchased through the day-ahead market (simply imbalances) is charged based on the price that is least favourable to the market participant. In other words, buyers will have to pay the greater of day-ahead or real-time prices, while sellers will receive the lesser.

All the transactions performed on day-ahead planning and day-ahead markets are reconciled monthly by MFSC. For example, if the market participants said to generate 100 MW electricity on a given hour of the day, and if actual consumption was to be 90 MW (could be more or less) then the difference between the actual consumption and planned consumption will be reconciled at the 15th of next month after the actual meter reading has been obtained. Imbalances is being charged based on the price that is least favourable to the market participant however during day-ahead planning the difference between the actual and planned consumption was priced by system marginal price.

With the implementation of dual pricing in Turkey, strategies of both demanders (suppliers) that are buying electricity from the wholesale market and generators (sellers) that are selling their electricity have been changed.

2.1. Strategies of demanders (suppliers)

Prior to implementation of dual pricing, if a demander buys electricity in the day-ahead market then, depending on their real-time consumption, the difference between the actual consumption and the amount they purchased from forward markets (simply imbalances) will be charged at the real-time price. It is important to note that, real-time consumption does not depend on price due to inelastic demand structure in electricity markets. Halicioglu (2007) estimates the income and price elasticities of the household energy demand in Turkey and the results indicates a price inelastic demand for the residential electricity.

For a demander expecting the price to be lower in the real-time market, it was optimal not to purchase electricity from the day-ahead market. Similarly, if the demander expected real-time electricity prices to be higher, then the demander would purchase an excess amount of electricity on the day-ahead market and sell to imbalance that which was not consumed on the real-time market. These strategies to gain excess revenue through arbitrage opportunities for demanders make the real-time and day-ahead market prices close to each other. However, this type of strategies puts the short-term system security in danger since the system operator would be in a difficult position as it expected the transactions to be real.

Under dual pricing, excess consumption in real-time always costs the demander the maximum of real-time and day-ahead prices. Similarly, under consumption costs the demander the minimum of real-time and day-ahead prices. Therefore, there is no arbitrage opportunity for the demander as under each scenario the demander is either worse off or indifferent. With the implementation of dual pricing for imbalances, the optimal strategy for the demander is to purchase electricity from the day-ahead market based on the best available consumption information since beating the market is impossible. This minimizes the amount of imbalances in the real-time market and increases the short-term system security.

2.2. Strategies of generators (sellers)

During the day-ahead planning phase, if the generator expected real-time prices to be higher than day-ahead prices, it was optimal for a generator to buy electricity from the day-ahead market and sell electricity in real-time to gain excess revenue from the price differences. To put this strategy in place during the day-ahead planning phase, the generator could bid a very high price in order to not submit its capacity to the day-ahead market (since participating in the day-ahead market is mandatory for all market participants during the day-ahead planning phase) and instead submit the capacity to the real-time market and gain revenue from the higher price. Similarly, the generator can simply spill energy in real-time and as a result be charged based on imbalance prices for its excess generation.

The real-time market price is expected to be higher if the actual demand for electricity is expected to be higher in the real-time market compared to purchases through day-ahead market, bilateral contracts and intra-day market. During the day-ahead planning phase, by bidding a higher price on the day-ahead market, the generator could ensure that there was no binding agreement for generating electricity. Given the generator expected the demand for electricity to be higher in real-time, by submitting its capacity to the real-time market (by bidding its marginal cost) or producing electricity in the imbalance market, it generates electricity in real-time.

During the day-ahead market phase, because of the dual-pricing scheme, it is not optimal for a generator to produce electricity in the imbalance market since the imbalances will be charged at the least favourable price. However, since it is not mandatory for a generator to participate in the day-ahead market, the generators could simply reserve its capacity to real-time as in the cases during the day-ahead planning phase. The generators strategy has not been changed significantly with the implementation of dual pricing rule under the case of the real-time prices are expected to be higher than day-ahead prices.

If the generator's expected price in real-time is lower than the day-ahead market price, the optimal strategy for the generator would be to sell its capacity on day-ahead market and bid to buy electricity from real-time balancing market if the real-time price is lower that the generators marginal cost. In addition to this strategy, the generator can also sell its capacity (as well as more than its actual capacity) on the day-ahead and buy the electricity from the imbalance market by simply not producing electricity. In this case, the amount of electricity committed to be produced would be bought from the imbalance market at the lower price. However, this strategy is not optimal under dual pricing since the generator will be paid for the amount of electricity that is produced in the imbalance market based on the minimum of real-time and day-ahead market prices. The generators can still bid to sell its pre-sold capacity in the real-time balancing market if the real-time price is lower than its marginal cost. Ideally, this should make the real-time and day-ahead market prices close to each other. This type of strategy puts the short-term system security in danger, as the sold capacity in the day-ahead either did not exist or the generator was not willing to produce electricity, the system operator would be in a difficult position as it expected the capacity to be real.

As a summary, under dual pricing, only the generators which are also a balancing unit (load serving entity) can gain revenue from arbitrage opportunities. It should be expected that, under dual-pricing rule, arbitrage strategies of generators would be sufficient enough to result the price differences being close to zero although dual-pricing rule limits the arbitrage strategies of both generators and demanders (suppliers). This conjecture is tested in Section 5 through analysing the market efficiency after the implementation of dual-pricing rule for imbalances.

3. Market efficiency

In an efficient market with no transaction costs, the expected return of the real-time market should be equal to the expected return in day-ahead forward market. The existence of profitable trading strategies (arbitrage opportunities) implies that the difference between the day-ahead and real-time prices is different than zero.

The day-ahead forward market prices F_t^{t-j} for the delivery time of t should incorporate all the information at time t-j on the expected real-time price of S_t for the same delivery period t and the predictability of forward prices should not be improved by historic information on prices. We expect that the forward prices are the best estimate of future spot prices. This implies that the expected value of forward prices is to be the same as spot prices, under the assumption of no transaction costs.

This relation can be formulated as

$$F_{t,i}^{t-j} = E\left(S_{t,i}^{t},\ \theta_i^{t-j}\right) \tag{1}$$

where i represents the settlement period (i.e. hourly, half hourly) and θ^{t-j} represent the available information at time t-j.

However, participants in forward markets are willing to pay a premium to avoid risk, especially to hedge their risks against price spikes in the spot market. The ex-ante risk premium can be defined as difference between forward price observed at time t-1 (F_t^{t-1}) for delivery of next day spot price (S_t^t) . So simply;

$$RP_{exante} = \quad F_{t,i}^{t-j} - E\left(S_{t,i}^{t},\ \theta_i^{t-j}\right) \tag{2}$$

In order to avoid modelling expected spot prices to calculate ex-ante risk premium by using assumptions, researchers simply calculate ex-post risk premium since today's expectation of future spot price data is unavailable by nature. Literature commonly assumes that the forecast error is random noise, resulting in the ex post risk premium being a good proxy for the ex ante risk premium. It follows that evidence of a nonzero ex post risk premium is also evidence of a nonzero ex ante risk premium (Haugom and Ullrich, 2012). Here it is important to state that the forward premium in electricity markets cannot be explained by familiar no-arbitrage storage methods due to the non-storable nature of electricity (Bessembinder and Lemmon, 2002).

Nonzero ex post risk premium that arises from a nonzero forecast error could be considered as an indication of market inefficiency especially where market participants have little experience regarding the dynamics of the market. Risk premium is expected to decrease (possibly disappear completely) as the market becomes more mature (Haugom and Ullrich, 2012). In this paper, the price convergence between the day-ahead and the real-time market is analysed similar to Longstaff and Wang (2004), Borenstein et al. (2001) and Arciniegas et al. (2003). Arbitrage opportunities are highlighted by the persistent price differences (risk premium) between the day-ahead market and the real-time market. In addition to work performed in Borenstein et al. (2001), Longstaff and Wang (2004) and Arciniegas et al. (2003), rolling estimation is used in this paper to understand the changes in risk premium before and after the implementation of dual –pricing in the Turkish electricity market.

4. Data and descriptive analysis

Day-ahead and real-time market prices are obtained on an hourly basis for the period from 01/12/2009 00:00 to 31/05/2016 23:00 from the Market Financial Settlement Centre (PMUM in Turkish) covering six and a half years, of which the first two are before the change in legislation.[4]

Table 1 summarizes the statistics time series of hourly electricity spot prices on balancing market. Prices are in Turkish lira per megawatt hour. The prices are the average spot price for each of the 24 h during the day. If the real-time demand is higher or lower than the supply, the system operator increases or decreases the prices until real-time demand is equal to supply.

In the electricity spot market, the average prices vary throughout

[4] The dataset and STATA commands used in this study are available on request for those who wish to replicate the econometric results presented in this paper.

Table 1
Summary statistics for hourly spot prices.

	Day-Ahead Planning (01/12/2009–30/11/2011)						Day-Ahead market and Dual Pricing (01/12/2011–31/05/2016)					
Hour	Mean	Std. Dev.	Skewness	Min	Median	Max	Mean	Std. Dev.	Skewness	Min	Median	Max
00–01	131.7	45.0	−0.77	0.01	139	216	145.5	49.3	0.11	0.00	150	580
01–02	116.3	49.7	−0.32	0.01	120	216	134.7	49.5	−0.60	0.00	140	266
02–03	99.6	55.0	0.02	0.00	100	216	123.0	55.3	−0.44	0.00	128	265
03–04	82.0	57.6	0.30	0.00	78	211	108.0	57.7	−0.16	0.00	110	265
04–05	72.5	59.4	0.56	0.00	62	228	98.1	59.0	−0.02	0.00	100	250
05–06	65.9	59.3	0.73	0.00	53	228	90.0	59.2	0.16	0.00	95	240
06–07	60.0	55.2	0.77	0.01	48	216	85.4	59.5	0.24	0.00	88	260
07–08	74.9	58.4	0.45	0.00	69	230	103.4	58.2	−0.14	0.00	110	257
08–09	109.9	60.6	−0.37	0.01	120	230	129.2	58.2	−0.57	0.00	140	257
09–10	137.0	52.0	−1.21	0.01	150	230	153.4	54.8	−0.47	0.00	166	580
10–11	149.2	47.3	−1.40	0.01	165	299	167.5	61.5	3.02	0.00	180	959
11–12	156.4	49.7	−0.25	0.01	170	420	175.0	78.8	9.56	0.00	183	2000
12–13	143.9	50.3	−0.90	0.01	161	330	170.3	84.2	8.86	0.10	179	2000
13–14	133.5	56.1	−0.28	0.01	141	420	159.1	67.4	3.93	0.10	169	1163
14–15	147.4	61.5	0.61	0.01	161	535	166.9	72.1	6.76	0.00	179	1600
15–16	141.4	58.8	0.03	0.01	151	420	167.1	78.2	9.40	0.00	177	2000
16–17	130.9	57.3	−0.37	1.00	139	382	157.5	68.2	3.49	0.00	169	999
17–18	125.4	61.7	−0.07	0.47	133	420	155.5	70.7	3.67	0.00	165	999
18–19	126.1	62.9	0.40	0.01	135	550	157.2	75.6	3.75	0.00	169	1100
19–20	126.7	55.3	−0.45	1.00	136	300	159.3	66.8	3.50	9.96	170	960
20–21	128.9	48.6	−0.59	0.01	135	230	156.6	56.6	2.55	5.00	160	820
21–22	128.5	45.6	−0.38	0.01	130	230	153.2	53.3	2.02	0.00	160	820
22–23	132.0	48.1	−0.59	0.01	135	212	153.1	51.4	1.50	0.00	160	820
23–00	143.5	43.4	−1.14	0.01	159	214	151.5	51.9	1.35	0.00	160	820

Table 2
Summary statistics for hourly day-ahead (forward) prices.

	Day-Ahead Planning (01/12/2009–30/11/2011)						Day-Ahead market and Dual Pricing (01/12/2011–31/05/2016)					
Hour	Mean	Std. Dev.	Skewness	Min	Median	Max	Mean	Std. Dev.	Skewness	Min	Median	Max
00–01	133.4	27.9	−0.80	10.00	135	187	148.4	33.2	−0.72	0.00	150	232
01–02	120.0	32.7	−0.86	9.75	121	176	141.2	33.9	−0.89	0.00	142	232
02–03	104.0	39.1	−0.62	5.00	110	172	124.8	37.9	−0.87	0.00	129	231
03–04	87.1	43.3	−0.18	4.19	90	190	107.1	41.0	−0.55	0.00	117	230
04–05	74.5	43.6	0.09	2.40	68	170	99.6	42.0	−0.52	0.00	110	229
05–06	65.7	41.1	0.19	0.10	62	164	94.3	41.3	−0.40	0.00	100	229
06–07	62.8	38.9	0.20	0.10	60	190	96.1	42.2	−0.36	0.00	100	230
07–08	82.5	39.6	−0.24	0.10	85	164	117.6	40.3	−0.84	0.00	123	230
08–09	111.7	43.5	−0.53	1.00	120	180	143.7	40.9	−0.95	0.00	147	231
09–10	133.1	39.2	−0.98	11.20	140	193	164.0	36.7	−1.17	0.00	170	234
10–11	146.3	33.5	−1.14	11.75	146	195	173.8	35.8	2.06	0.00	180	756
11–12	157.5	35.5	2.03	55.00	161	450	179.0	57.9	19.42	0.00	180	2000
12–13	148.0	29.9	−0.77	11.90	150	250	173.9	63.1	16.41	0.94	175	2000
13–14	143.2	33.5	0.31	11.90	142	420	167.6	42.8	7.73	5.03	170	1163
14–15	150.5	46.2	2.63	11.80	149	535	172.5	49.8	14.57	1.08	176	1600
15–16	147.0	41.9	2.28	11.50	145	535	170.8	57.8	19.40	1.07	175	2000
16–17	138.6	37.5	−0.18	11.70	140	380	165.6	41.6	4.99	1.02	169	999
17–18	133.8	39.5	0.00	10.00	140	420	162.5	45.2	4.53	5.04	165	999
18–19	130.6	40.9	1.05	11.35	136	550	160.6	45.3	4.13	0.82	160	926
19–20	131.6	34.0	−0.60	10.00	135	215	159.7	40.2	6.07	20.03	160	952
20–21	133.8	28.9	−0.38	40.00	135	195	159.0	31.8	2.38	47.69	158	599
21–22	130.9	28.9	−0.14	54.90	130	192	154.7	29.6	0.60	54.78	152	450
22–23	134.8	32.8	−0.35	52.04	135	191	154.3	32.1	−0.46	4.46	155	250
23–00	142.2	26.9	−0.72	42.00	145	192	151.5	34.6	−0.74	0.78	151	250

the day. The prices in the early morning hours are lower compared to the late afternoon peak times, where the demand is higher. The figures in Table 1 also show that the variation in the spot price is considerably high. The standard deviations for the spot prices are almost half of the average values for the morning hours and one third of the average values for the peak hours (where the prices are relatively high compared to morning hours).

After the implementation of dual pricing, the maximum spot prices, especially during the late afternoon hours, are very high compared to the maximum prices before the implementation. The maximum price is 2000 TRY/MW for the hours 11, 12 and 15 which is more than 11 times the mean value for these hours.

The summary statistics in Table 1 also demonstrate the highly right-skewed distribution of electricity spot prices. After the implementation of dual-pricing, the skewness is positive for the day and peak hours due to the convex nature of the power production function. This is also consistent with the implications of the model presented in Bessembinder and Lemmon (2002) and Longstaff and Wang (2004). The skewness before the implementation is around zero for all hours, indicating that there were no significant price spikes, this is contrary to general literature around behaviour of electricity prices. Skewness of the electricity spot prices increases significantly after the implementation of dual pricing. One of the implications of not allowing market participants to explore arbitrage opportunities under dual pricing could be seen as increase on skewness, making the system more vulnerable to price spikes.

Table 2 summarizes the statistics for the electricity day-ahead (forward) prices both before and after the implementation of dual pricing. The prices are in terms of TRY per MW as spot prices. The day-ahead prices are determined at 3 p.m. for each day where delivery is for the next day of the respective hour. The market operator collects all the bids from market participants and announce the price where supply is equal to demand for each hour of the following day.

The statistics of the electricity forward prices are found to be similar to spot prices. The average price is lower for night hours compared to day and peak hours. Following the implementation of dual pricing, skewness is positive for the day and peak hours whereas skewness is around zero for the rest of the day. The standard deviation of the forward prices are lower than the spot prices for all hours, this is in line with the expectation of forward prices which tend to be less volatile than spot prices. Forward prices do not display as much extreme variation as spot prices, however the skewness of the forward prices are higher than spot prices which is not consistent with the findings of Longstaff and Wang (2004).

We also check for the stationarity in the difference of real-time and day ahead price series used in empirical analysis by performing augmented Dickey-Fuller test statistic using a generalized least squares rationale (DF-GLS) where the null hypothesis is that the series are non-stationary. Elliott et al. (1996) have shown that this test has significantly greater power than the previous versions of the augmented Dickey–Fuller test. The results of unit root tests are presented in Table 3.

Series is said to be a stationary series if its mean, variance and autocorrelation are independent of time. The unit root test shown in Table 3 rejects the null hypothesis that the series are non-stationary for all hours except for hour 9 of day-ahead forward prices.[5]

There are various studies analysing the stationarity of electricity prices with contradictory results. De Vany and Wall (1999) performed an augmented Dickey and Fuller unit root tests on peak and off-peak prices for 11 regional markets in the western United States during 1994–1996 and conclude that the spot prices are non-stationary except for the Northern California market. In contrast, Knittel and Roberts (2005) states that electricity prices display the characteristic of stationarity in both price level and squared prices based on their analysis for California electricity prices. Additionally, Arciniegas et al. (2003) performed the augmented Dickey and Fuller unit root test for New York, California and PJM and found that in all the three states, some hours were stationary during the California's energy crisis in 2000.

It is important to note that, Eqs. (1) and (2) imposes the implicit assumption of unbiasedness (the coefficient of the spot price is assumed to be unity). Due to the contradictory stationarity characteristics of the day-ahead and spot prices in Turkish electricity market, we haven't performed a cointegration analysis to check if the expected return in both markets are considered to be same and market participants cannot gain excess profit through trading strategies.

Table 3
Unit root tests on difference of real-time and day ahead price series.[a]

Hours	Day-Ahead Planning (01/12/2009–30/11/2011)	Day-Ahead market and Dual Pricing (01/12/2011–31/05/2016)	Overall Period (01/12/2009–31/05/2016)
00–01	−4.70***	−5.58***	−6.67***
01–02	−0.62	−4.18***	−1.15
02–03	−0.64	−4.86***	−1.72*
03–04	−3.88***	−6.69***	−7.57***
04–05	−4.70***	−6.24***	−7.64***
05–06	−4.50v	−4.25***	−6.52***
06–07	−4.89***	−4.31***	−5.31***
07–08	−4.20***	−4.46***	−5.88***
08–09	−1.72*	−4.47***	−3.16***
09–10	−0.20	−4.20***	−0.61
10–11	−2.54**	−8.83***	−4.82***
11–12	−3.36***	−8.52***	−6.67***
12–13	−3.35***	−6.79***	−6.39***
13–14	−3.58***	−6.00***	−6.15***
14–15	−2.99***	−2.51**	−4.63***
15–16	−2.36**	−6.45***	−4.52***
16–17	−2.44**	−6.18***	−4.12***
17–18	−2.81***	−5.73***	−4.84***
18–19	−2.75***	−5.82***	−5.55***
19–20	−3.38***	−6.15***	−6.59***
20–21	−3.59***	−2.44**	−5.59***
21–22	−2.79***	−1.60	−4.66***
22–23	−0.80	−2.06**	−1.32
23–00	−1.93*	−1.59	−2.71***

(Level of significance of 10% is marked by *, 5% by **, and 1% by ***).

[a] Optimal lag length has been determined based on minimum Akaike Information Criterion (AIC) and maximum lag to run the test has been determined according to the method proposed by Schwert (1989).

5. Emprical analysis

In order to examine the existence of persistent differences between day-ahead and real-time prices, we test if the day-ahead price converges to the real-time price by taking the sample mean of ex-post risk premium and testing if the mean are statistically different from zero. The econometric model has been constructed as;

$$F_t^{t-j} - S_t^t = \theta + \varepsilon_t \tag{3}$$

where $\theta = 0$ if there is no statistical evidence on persistent differences between day-ahead and real-time prices, which implies the market is efficient. The constant term, θ, that are statistically significant than zero indicate a risk premium in the electricity market, meaning the mean of the differences between day-ahead and real-time prices had

[5] The unit root tests also has been performed by determining optimal lag lengths based on minimum Schwarz Information Criterion (SIC) instead of AIC. For the period of Day-Ahead market and Dual Pricing (01/12/2011–31/05/2016) the null hypothesis that the series are non-stationary has been rejected for all hours where level of significance is max 10%.

Table 4
Presence of risk premium in day-ahead market.

Hours	Coef θ	Standard errors	t-statistics
00–01	2.52	0.98	2.58**
01–02	5.64	0.92	6.15***
02–03	2.63	0.97	2.71***
03–04	0.95	0.94	1.00
04–05	1.69	0.97	1.75*
05–06	2.95	1.06	2.77***
06–07	8.33	1.15	7.26***
07–08	12.20	1.11	11.02***
08–09	10.60	0.99	10.66***
09–10	6.15	0.95	6.46***
10–11	3.51	1.14	3.09***
11–12	3.04	1.16	2.63***
12–13	3.78	1.27	2.98***
13–14	8.86	1.28	6.91***
14–15	4.85	1.21	4.00***
15–16	4.27	1.26	3.39***
16–17	7.92	1.31	6.03***
17–18	7.43	1.31	5.65***
18–19	3.72	1.35	2.76***
19–20	1.76	1.27	1.39
20–21	3.11	1.22	2.55**
21–22	1.83	1.15	1.59
22–23	1.69	1.09	1.56
23–00	−0.39	1.08	−0.36

(Level of significance of 10% is marked by *, 5% by **, and 1% by ***).

been shifted over time.

The above equation has been estimated for each hour by OLS regressions using Newey and West (1987) standard errors with one lag.[6] All t-statistics reported are based on heteroskedastic and autocorrelation consistent estimates of the variances.

As shown in Table 4, based on the results for the individual hours, there is clear evidence of a significant risk premium. The presence of a risk premium in the day-ahead market is statistically significant for 19 of the 24 h. Furthermore, all hours has a positive risk premium apart from hour 23 which statistically insignificant. In literature, a negative premium is referred to as normal backwardation, whereas a positive premium is referred to as contango (Longstaff and Wang, 2004). The positive risk premium observed is not consistent with that found in Longstaff and Wang (2004), who undertook a risk premium analysis for the PJM electricity markets and found the mean forward premium to vary significantly across hours in both magnitude and sign. We believe that the main reason why our results are different is the effect of change in change in strategic behaviours of market participants after the implementation of dual-pricing rule.

Bessembinder and Lemmon (2002) derive an equilibrium model for the forward electricity prices to understand the two potential determinants of the risk premium. Their model predicts risk premium being negatively related to the variance of spot prices and positively related to the skewness of the spot prices. Longstaff and Wang (2004), testing the predictions, find risk premium to be negatively related to variance and positively related to skewness, therefore concluding significant risk premium being present in forward prices at PJM. Haugom and Ullrich (2012) replicate Longstaff and Wang (2004) with more recent data and find that over an extended period, both implications hold for PJM contracts only for relatively low spot price levels. In this paper, we focus on existence of risk premium as an indicator of market inefficiency. As our results show that real-time and forward prices are converging and that there is no evidence on risk premium for the recent periods, an analysis to understand the potential determinants of the risk premium is not incorporated in our paper.

5.1. Rolling estimations

In order to understand the stability of the constant term θ in Eq. (3), the price convergence model has been analysed by using rolling estimations for each period and each hour by OLS regressions using Newey and West (1987) standard errors with one lag.

For each hour, we estimate the Eq. (3) on a rolling basis as

$$F_t^{t-j}(n) - S_t^t(n) = \theta(n) + \varepsilon_t \tag{4}$$

where n is the window period of 365 days. The figure below shows the estimated θ and dotted lines shows the 95% confidence interval based on Newey-West heteroskedasticity and autocorrelation consistent estimates of the variances.

The graphs in Table 5 depict the rolling estimation results for peak hours (17.00–22.00), in which the electricity consumption is at its highest level throughout the day. The dotted lines shows two robust standard error confidence bands of the average price differences between day-ahead and spot prices.

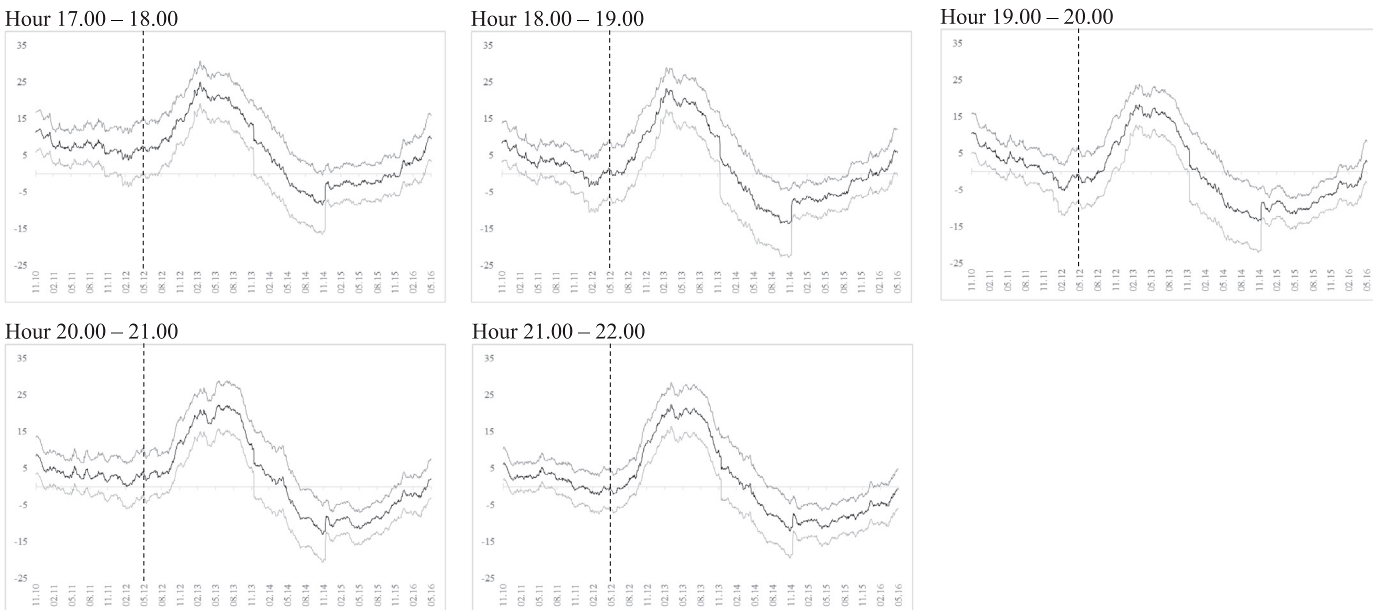
For all peak time hours, the risk premium significantly increases following the change in legislation. The vertical dotted line shows the date May 2012 which is the midpoint of the period starting December 2011 (implementation date of dual pricing regime) and ending December 2012 (end date of rolling estimation with a 365 day window that starts at December 2011). The rolling estimation of the risk premium clearly shows a structural break around the same time of the implementation of the dual pricing.

The change in strategic thinking of the market participants after the implementation of dual pricing increases the risk premium of the market. As explained in Section 2, under the dual-pricing system, it should be expected that real-time prices would be lower compared to day-ahead market prices since the demanders (suppliers) cannot exploit the arbitrage opportunities.

However, in the long run the risk premium in the market reduces and converges to zero. The newness and uniqueness of the wholesale

[6] By using the correlograms of the residuals of each regression, using one lag assumed to be sufficient to take into account the serial correlation in the residuals. The results are similar under different lag assumptions.

Table 5
Rolling estimation results of ex-post risk premium for peak hours (17.00–22.00). (The Figures presents the constant term results from rolling regression of ex-post risk premium on constant term, Eq. (3), using a window of 365 days. The dotted lines represents the 95% confidence interval, ± 1.96 times standard errors from the mean values of estimated constant term. The x-axis represents the end date of the window used in rolling estimations).



power markets could result in the possibility of observed forward prices reflecting the inexperience of industry participants, this may differ to the pricing structure observed in a long-run equilibrium (Bessembinder and Lemmon, 2002). Figlewski (1984) observed this and reported market prices for stock index futures deviated significantly from theoretical values at first, but converged to predicted values following some time. Dual pricing discourage participants seeking arbitrage opportunities by penalizing the imbalances. The results shows that, although the risk premium increases after the implementation of dual-pricing, risk premium decreases over time. This indicates that market efficiency increased through time as the market became more mature.

The Table 6 shows the rolling estimation results for day hours (06.00–17.00). The results for day hours are very similar to peak hours, apart from morning hours between 6 a.m. and 8 a.m. where the demand is relatively low.

The Table 7 shows the rolling estimation results for night hours (22.00–06.00) where the demand is relatively low compared to day and peak hours. There is no significant indication of a structural break for the risk premium, apart from hours 22 and 23. The risk premium is around zero for the periods before and after the implementation of dual pricing, implying that the market is more efficient for the hours where demand is relatively low.

6. Conclusion and policy implications

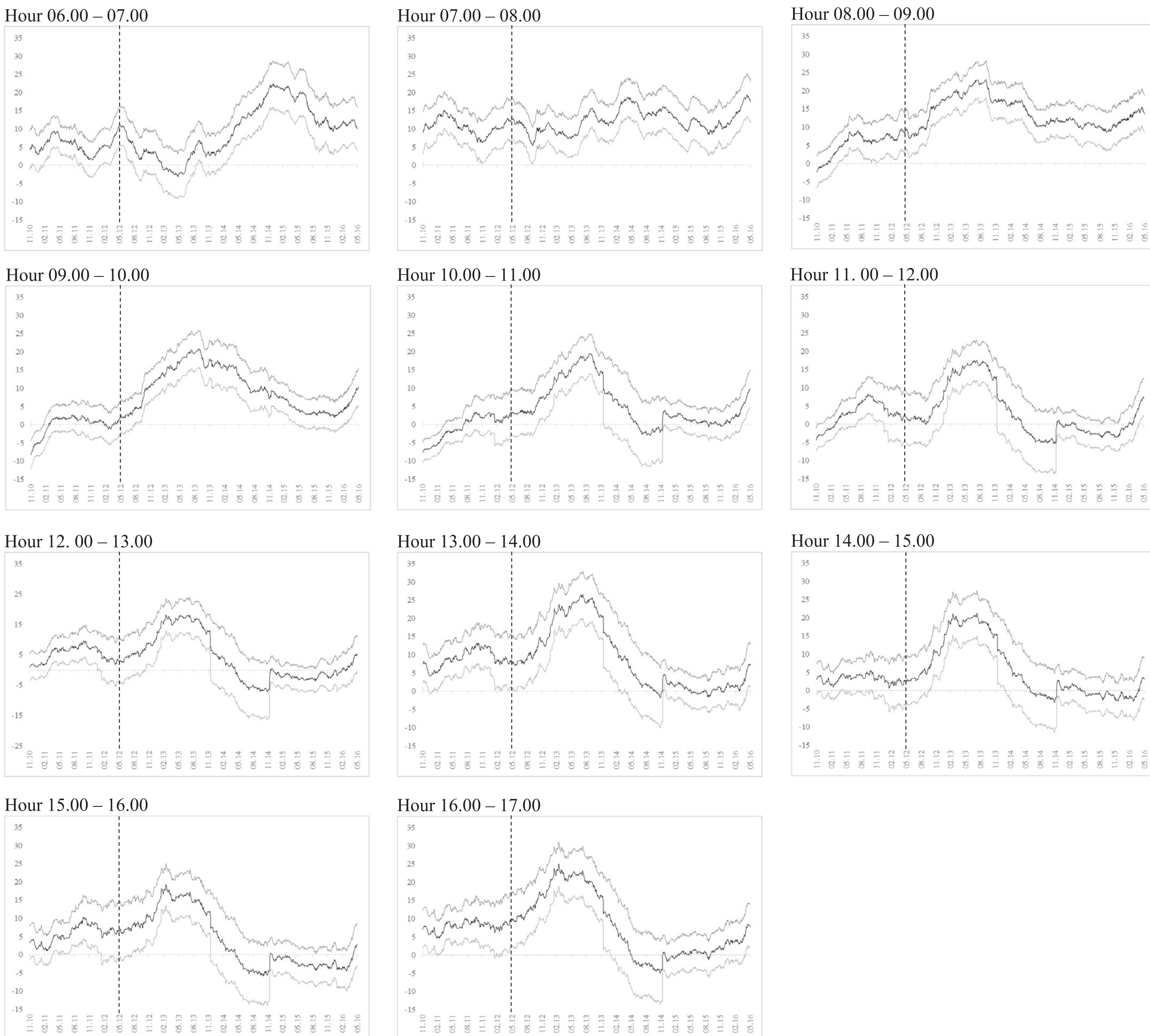
This study finds that real-time prices are found to be significantly lower than day-ahead prices after the implementation of dual pricing regime showing a positive risk premium in day-ahead market especially for the day and peak hours where the demand is relatively high compared to night hours.

Dual imbalance pricing regime is a policy tool that is currently being used in Turkey (as well as other countries such as Netherlands, England etc.) in order to incentivise market participants to minimize their imbalances by discouraging market participants seeking arbitrage opportunities by making it unattractive for them to make false bids or offers since these could harm system security. False bids or offers could harm short-term system security, for example by implying greater capacity in the market than actually exists.

While dual pricing increases the short-term system security by discouraging participants to seek arbitrage opportunities by making it unattractive for them to make false bids or offers, this study found that it also created a persistent difference between day-ahead and spot electricity prices (risk premium) which implies a market inefficiency. This study finds that there are significant positive forward premium exists in Turkish electricity market. The presence of a forward premium in the day-ahead market is statistically significant for 19 of the 24 h and all has a positive risk premium, indicating that day-ahead market prices are persistently higher than real-time prices. The existence of positive risk premium implies the existence of profitable trading strategies (arbitrage opportunities) in Turkish electricity market.

However, we further examine how the risk premium changes over time using rolling estimations and find that in the long run after the implementation of dual pricing in Turkey, as market participants have more experience regarding the dynamics of the market, the difference between real-time prices and day-ahead prices converges to zero since the dual-pricing regime enforce market participants to forecast accurately by punishing the forecast error.

Table 6
Rolling estimation results of ex-post risk premium for day hours (06.00–17.00). (The Figures presents the constant term results from rolling regression of ex-post risk premium on constant term, Eq. (3), using a window of 365 days. The dotted lines represents the 95% confidence interval, ± 1.96 times standard errors from the mean values of estimated constant term. The x-axis represents the end date of the window used in rolling estimations).

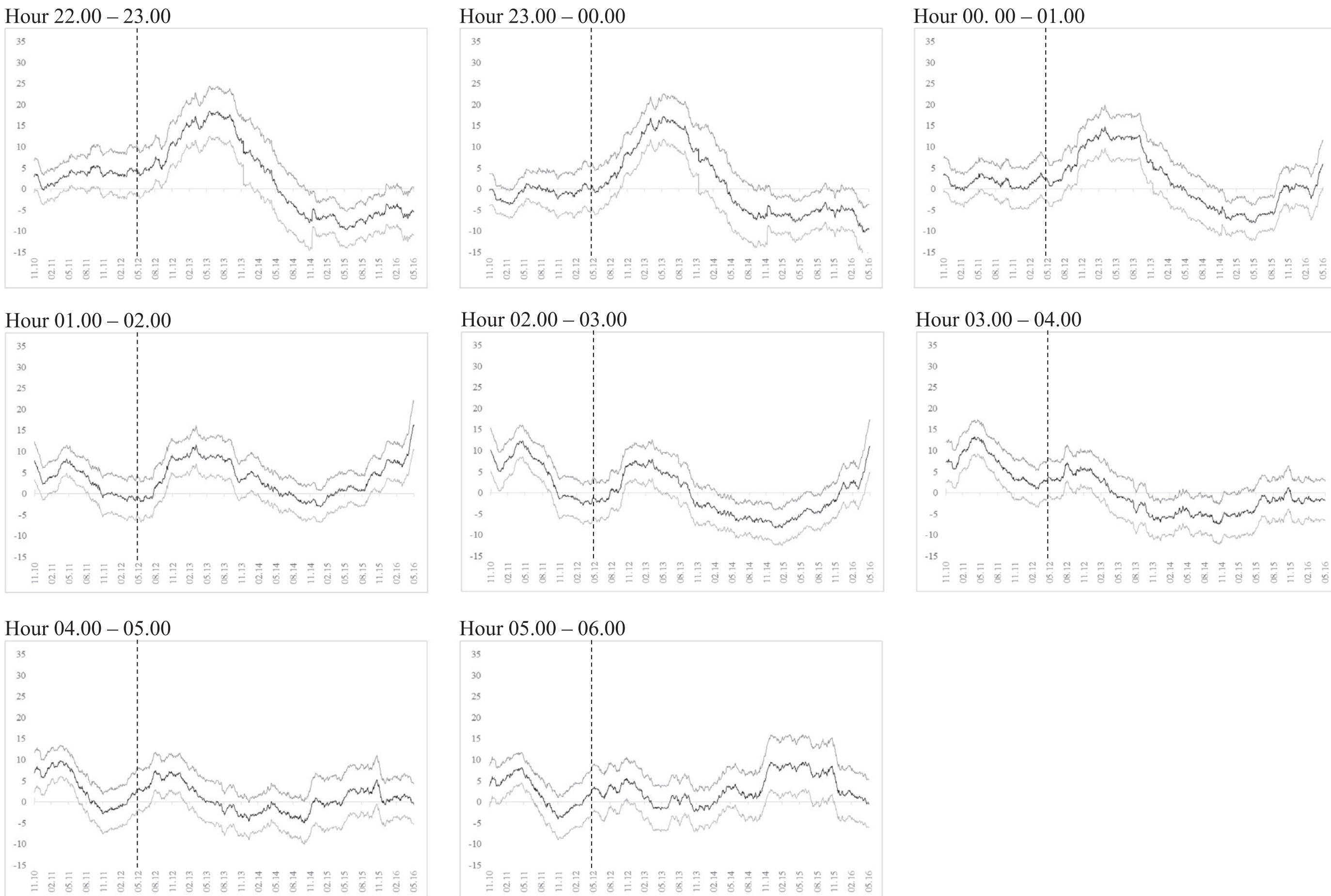


Newly introduced wholesale power markets could result in the observed forward prices differing from the pricing structure that will be observed in a longer-run equilibrium, reflecting the inexperience of market participants. The results show that, although there is an increase in risk premium after the implementation of dual-pricing rule, it decreases over time. This indicates that market efficiency increased as the market became more mature.

Acknowledgements

We would like to thank Alper Gunaydin, George Bagdatoglou, Sohrab Khan, Gaber Burnik and Metin Celebi for their helpful comments and suggestions.

Table 7
Rolling estimation results of ex-post risk premium for night hours (22.00–06.00). (The Figures presents the constant term results from rolling regression of ex-post risk premium on constant term, Eq. (3), using a window of 365 days. The dotted lines represents the 95% confidence interval, ± 1.96 times standard errors from the mean values of estimated constant term. The x-axis represents the end date of the window used in rolling estimations).



References

Arciniegas, I., Barrett, C., Marathe, A., 2003. Assessing the efficiency of US electricity markets. Utilities Policy 11 (2003), 75–86.
Bessembinder, H., Lemmon, M.L., 2002. Equilibrium pricing and optimal hedging in electricity forward markets. J. Financ. 57, 1347–1382.
Boogerta, A., Dupont, D., 2005. On the effectiveness of the anti-gaming policy between the day-ahead and real-time electricity markets in The Netherlands. Energy Econ. 27, 752–770.
Borenstein, S., Bushnell, J., Knittel, C., Wolfram, C., 2001. Trading inefficiencies in california's electricity markets. UCEI, Working Paper No. PWP-086.
De Vany, A.S., Wall, W.D., 1999. Cointegration analysis of spot electricity prices: insights on transmission efficiency in the western US. Energy Econ. 21, 448–453.
Elliott, G.R., Rothenberg, T.J., Stock, J.H., 1996. Efficient tests for an autoregressive unit root. Econometrica 64, 813–836.
Figlewski, S., 1984. Hedging performance and basis risk in stock index futures. J. Financ. 39, 657–669.
Halicioglu, F., 2007. Residential electricity demand dynamics in Turkey. Energy Econ. 29, 199–210.
Haugom, E., Ullrich, J., 2012. Market efficiency and risk premia in short-term forward prices. Energy Econ. 34, 1931–1941.
Jha, A., Wolak, F., 2013. Testing for Market Efficiency with Transactions Costs: An Application to Convergence Bidding in Wholesale Electricity Markets. Available at: ⟨http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/CAISO_VB_draft_V8.pdf⟩.
Knittel, C.R., Roberts, M., 2005. An empirical examination of restructured electricity prices. Energy Econ. 27, 791–817.
Longstaff, F.A., Wang, A.W., 2004. Electricity forward prices: a high-frequency empirical analysis. J. Financ. 59, 1877–1900.
Newey, W.K., West, K.D., 1987. A simple positive semi-definite, heteroskedasticity and autocorrelation consistent covariance matrix. Econometrica 55, 703–708.
Quan, N.T., Michaels, R.J., 2001. Games or opportunities: bidding in the California markets. Electr. J. 14, 99–108.
Schwert, G.W., 1989. Tests for unit roots: a Monte Carlo investigation. J. Bus. Econ. Stat. 2, 147–159.
TEIAS, June 2014. Türkiye Elektrik Enerjisi 5 Yillik Üretim Kapasite Projeksiyonu (2014–2018).
Weron, R., Zator, M., 2014. Revisiting the relationship between spot and futures prices in the Nord Pool electricity market. Energy Econ. 44, 178–190.