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On the effectiveness of the anti-gaming policy between the day-ahead and real-time electricity markets in The Netherlands

Alexander Boogert^a, Dominique Dupont^{b,*}

^aEssent Energy Trading, P.O. Box 689, 5201 AR's-Hertogenbosch, The Netherlands

^bSchool of Business, Public Administration & Technology, University of Twente, Capitoel, P.O. Box 217, 7500 AE Enschede, The Netherlands

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Abstract

In this paper, we study the linkage between two related markets for electricity in The Netherlands: the day-ahead market and the real-time market. The Dutch regulator wants to prevent trading across these two markets and has set up a dual pricing system for this purpose. In this paper, we test the effectiveness of this policy by studying the ex post profitability of trading strategies spanning the two markets over various time segments. Our results show that profits generated by these strategies are rarely positive on average and always characterized by very large potential losses, which dwarf the mean profit when the latter is positive.

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1. Introduction

The objective of this paper is to study relations between the day-ahead market and the real-time market for electricity in The Netherlands. Since the product to be delivered is

* Corresponding author. Tel.: +31 53 489 4470; fax: +31 53 489 2159.

E-mail address: d.y.dupont@bbt.utwente.nl (D. Dupont).

the same in both markets, it seems natural to compare the prices between the two markets.

Day-ahead and real-time markets for electricity seem strongly interconnected in The Netherlands and in the world at large. However, it is by design very hard to trade between both markets in The Netherlands. For example, an investor who considers the day-ahead price to be too high relative to his own expectations of the price in the real-time market would find it hard to implement a spread strategy, i.e., to sell in the day-ahead market and buy back in the real-time market. The regulator in The Netherlands sees any spread strategy as “gaming” and has designed a system to prevent them. Actually, the real-time market is referred to as the “imbalance market”.

The objective set by the Dutch regulator TenneT to the imbalance market mechanism is stated in [TenneT \(2001b, p. 4\)](#): “The anti-gaming requirement results from the program responsibility. Imbalance should be a priori unintentional and a posteriori minimal.” Our goal is to test the effectiveness of this anti-gaming policy of the Dutch regulator by studying the profitability of trading strategies taking an opposite position in the two markets.¹ Besides of course the Dutch regulator, the results of such a study are potentially valuable to economists interested in regulatory issues, foreign regulators, and naturally short-term electricity traders.

Reviewing the performance of the Dutch imbalance market 3 months after its inception, the regulator noted that the high unpredictability of the imbalance price observed over the period constituted “the most important anti-gaming element of the system.” Our paper builds on this work by using a longer data set of 3 years and by comparing the Dutch market to similar markets in other countries. In the review ([TenneT, 2001b, Table 2](#)), the relation between the day-ahead and imbalance markets is studied by means of summary statistics as in our [Table 2](#). We extend this approach by looking at strategies that span the day-ahead and imbalance markets. Clearly, because they are based on the creation of intended imbalances, the trading strategies we study are gaming in nature and would not be accepted by the regulator.

We examine the realized profits that would result from implementing several simple strategies. These strategies, which are based on taking opposite positions in the day-ahead market and the imbalance market, depend at most on the hour of the day. In contrast traders may possess more precise information on weather related and other technical factors. To summarize, traders consider conditional (“ex ante”) means and variances of trading profits while we look at unconditional (“ex post”) moments. We assume that agents make unbiased forecasts, so that the conditional and unconditional means of forecast errors are zero. The profit generated by our trading strategies is rarely positive on average and always characterized by very large potential losses, which dwarf the mean profit when the latter is positive.

The design of electricity markets and the way the regulator deals with intended imbalances vary across the world. For example, [Borenstein et al. \(2001\)](#) indicate that in the

¹ Our research question is related but not identical to the planning problem faced by generators. A generator has to decide when to sell its future power and has by definition a net long position overall. Our strategies are volumetrically neutral.

early days of the Californian market, no penalty was imposed on participants who had systematic differences between their day-ahead and real-time schedules. However, when the imbalance market handled over 33% of the total volume, a penalty was introduced to discourage the use of the real-time market. Borenstein et al. found some price differences between the day-ahead and the imbalance market and claim that markets were unable to trade on these differences due to rapid changes in market rules and economic fundamentals.

Other research on the day-ahead and real-time electricity markets has mainly focused on U.S. markets where deregulation started early. [Bessembinder and Lemmon \(2002\)](#) formulated a general equilibrium model for the day-ahead forward prices when speculators cannot participate. [Saravia \(2004\)](#) studies the effect of speculators on the relation between the day-ahead and real-time market in the New York electricity market. Studying the PJM electricity market in the United States, [Longstaff and Wang \(2004\)](#) find that prices on the day-ahead market are on average higher than on the real-time market and relate this spread to several risk factors.

The paper proceeds as follows: Section 2 starts with the introduction of the overall structure of electricity markets, giving more attention to the situation in The Netherlands. Section 3 describes our dataset and Section 4 analyses the profitability of selected trading strategies. We will introduce a new element in the profitability analysis of inter-market trade by quantifying the impact of extra orders on market-clearing prices. Section 5 concludes our study with a discussion about the height of the Dutch imbalance prices.

2. Characteristics of deregulated markets

2.1. General characteristics

Electricity markets are recent institutions that were created by the deregulation policies of the last two decades. The objective of these policies was to replace the systems of regulated regional or national monopolies with competitive markets. Deregulation of the U.S. electricity market began with the 1992 Energy Policy Act. Deregulation in the European Union started when member states, to varying degrees, passed national regulations to implement the 1996 European directive establishing common rules for the internal market for electricity. This directive was replaced by a new directive in June 2003 but the fundamental objectives remain the same: the creation of a free internal market for electricity in the European Union through the unbundling of network activities from generation and supply, the introduction of competition between suppliers, and the integration of the electric grids of member states.

Unlike other commodities, electricity cannot be easily stored. Moreover, any imbalance between supply and demand may bring the whole grid down if the voltage on the grid varies outside a narrow band. In the new market model, the transmission of electricity, by its technical nature a natural monopoly, remains under public control and is managed by an “Independent System Operator” (or ISO). The ISO is responsible for the reliability of the transmission system and for balancing supply and demand on the grid at all times. It does

so by running several markets: a day-ahead market, a real-time market, and a reserve market. Next to these very short maturities, contracts with maturities ranging from several months to several years can be traded on over-the-counter (or OTC) forward markets. The precise structure of the reserve, real-time, and longer-term forward markets, the share of power exchanges in the overall electricity consumption, the role of the ISO, and the nomenclature vary from country to country, even within the European Union [ETSO (2003)].

Because market participants cannot perfectly forecast supply and demand conditions 1 day ahead, they need to adjust their orders shortly before the physical exchange of electricity takes place. This is done on the real-time (or imbalance) market. This market often uses a finer time grid for the exchange of electric power (about 5 to 15 min) than on the day-ahead market (typically 1 h) or on forward markets. For the latter, delivery occurs over a pre-specified time interval rather than at one point in time and the length of this time interval increases with the maturity of the contract.

The ISO needs to fine-tune supply and demand on a second-by-second basis. To do this, the ISO must be able to provide additional capacity at short notice to satisfy demand or temporarily deny access to the grid to prevent system overload. Since the ISO typically does not own generation capacity, it acquires the right to use capacity in the “reserve capacity” market to perform the second-by-second balancing of demand and supply. In most countries, the owner of the generator receives a capacity payment for giving the ISO the freedom to use the generator and a payment proportional to the amount of energy produced if the generator is called into service.

2.2. Deregulation in The Netherlands

The Netherlands was among the first countries in the European Union to liberalize its electricity market. The Dutch ISO, TenneT, manages the high-voltage grid (380 and 220 kV), which interconnects regional electricity networks and links the Dutch grid to Belgium and Germany. TenneT, a wholly state-owned company, ensures access to the domestic high-voltage network and organises, through its subsidiaries, the day-ahead market for electricity (Amsterdam Power Exchange or APX) and the imbalance market. It also auctions capacity at the five cross border interconnectors.

Most of the wholesale trade of electricity in The Netherlands occurs on the OTC market as long- and medium-term bilateral contracts. Contracts have up to 2 years to maturity and are based on the delivery of electric power over some time blocks (year, quarter, month). Longer blocks are traded at longer horizons. The delivery is handled by the APX, ensuring integration between the day-ahead market and the longer-term forward market.

The APX aggregates buy and sell orders for electricity to be delivered the following day for each individual hour. Then it computes 24 market-clearing prices for that day. Physical delivery is realized using the high-voltage network managed by TenneT. The APX publishes the bid–ask ladder and the resulting hourly market-clearing prices and volumes on its website. Although the electricity traded on the APX represents only 15 to 20% of the Dutch daily consumption, the APX is considered an important benchmark.

To ensure the stability of the electricity network, supply and consumption of electricity need to be in balance at all times. Several organisational designs are available to structure this short-term balancing of electric power, from market-based to regulator-based. The Netherlands, like many but not all the member states of the European Union, opted for a market-based balancing mechanism.² TenneT communicates directly with two kinds of parties. First, TenneT requires all parties who can create imbalances to register as Programme Responsible Parties (PRPs). Second, TenneT contracts imbalance services with several generators, which are called Regulation and Reserve Power Suppliers (RRPSs).³ PRPs must submit their production and consumption plans for every 15-min period (the Programme Time Unit or PTU) of the following day to TenneT. This allows TenneT to check the consistency of these plans network wide. PRPs strive to meet their forecasts but are allowed to submit changes to their plans up to 1 h before realization. At that point, called “gate-closure,” the plans presented to TenneT become firm. More information on Programme Responsibility can be found in [TenneT \(2002\)](#).

Discrepancies between the final schedules and the power that actually needs to be delivered on the grid are compensated for on the imbalance market. These differences stem from demand forecast errors and unanticipated shortfalls in supply, due to generators outage for example.

2.3. The Dutch imbalance pricing system

As stated by TenneT in its 2001 Annual Report, “the imbalance system is based on the principle that the party causing an imbalance pays the cost TenneT incurs to make up for the imbalance (in order to encourage operational efficiency on the part of the market players).” Another goal of the Dutch imbalance pricing system, see [TenneT \(2001b\)](#), is to minimize imbalances and to prevent intended imbalances (“gaming”). Moreover, to ensure that enough participants bid in the imbalance market, generators that own more than 60 MW of capacity are obligated to bid a minimum amount on the daily imbalance market. However, [Harris et al. \(2004\)](#) suggest that the impact of this regulation on the imbalance market may be limited due to some legal technicalities.

Regulation and Reserve Power Suppliers (RRPSs) post the prices at which they are willing to provide positive and negative regulation power and reserve power. TenneT aggregates the bids for regulating power and reserve power into a single “bid price ladder for the regulatory and reserve power” and partially publishes it on its website. TenneT dispatches the power according to the prevailing merit order on a 4-s basis. After having introduced this ladder in more details, we will explain how the imbalance price is determined.

² For more information, we refer the reader to the second and third benchmarking reports on the implementation of the internal electricity and gas market written for the [Commission of the European Communities \(2003\)](#).

³ To be precise, three types of balancing power are available, depending on how fast suppliers can be called upon by TenneT to provide “positive power” (increase supply) or “negative power” (decrease supply or increase consumption): regulation (almost instantly), reserve (after 15 min), and emergency power (only used in extreme cases).

Fig. 1 shows a detailed bid price ladder posted by TenneT on its website to illustrate the principle of the Dutch market-based balancing mechanism. This ladder determines the price of power exchanged between TenneT and the RRPSS and comprises two parts. The upward regulation side (on the right) is used when power has to be injected in the grid to maintain balance; the downward regulation side (on the left) is used when power has to be drained from the grid. In this particular example, if TenneT calls a maximum of 200 MW of positive power within the PTU, the positive power dispatch price is € 29.98 per MWh. The price increases to € 34.98 per MWh if TenneT calls a maximum of 400 MW. The pricing on the downward regulating side is similar: if TenneT calls bids for negative power for a maximum of 100 MW, the negative power dispatch price is € 5.00. If the maximum of negative power called within the PTU increases to 300 MW, this price falls to minus € 24.93. From this bid–ask ladder, one is able to read the exact dependence of the imbalance price on the imbalance volume. In practice, TenneT publishes only a few points of the bid–ask ladder as in the left part of the figure and not the whole bid–ask ladder. We will discuss this problem in Subsection 4.2.

In the previous example, we saw that the price of negative power can even be negative: TenneT may pay for someone to drain power from the system. Imbalance prices may turn negative when there is a large glut of power on the network relative to demand, which so far only occurred at night. Because an excess supply can bring the whole grid down,

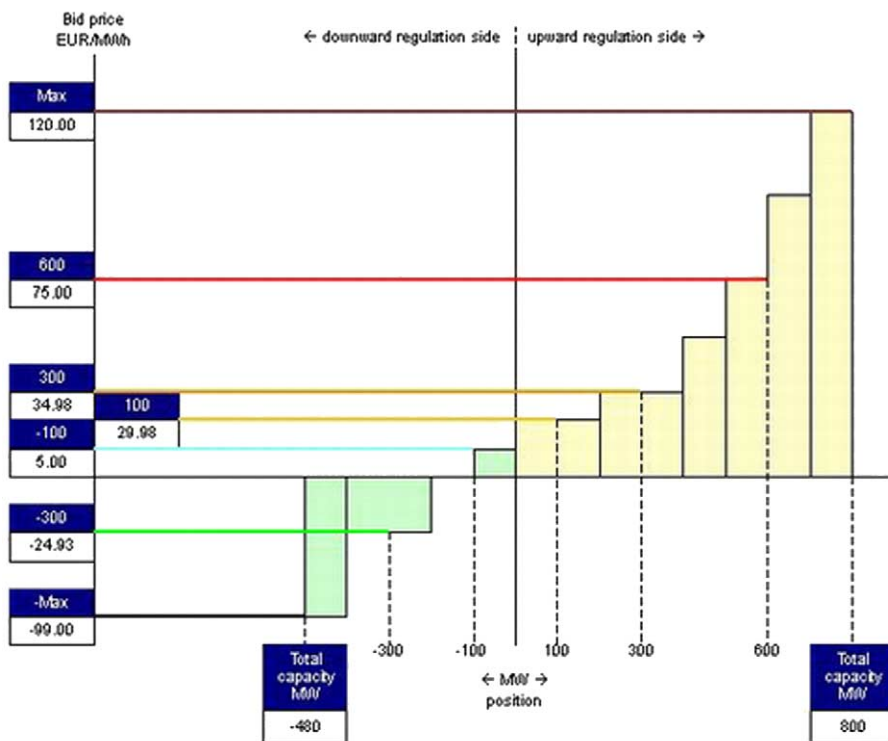


Fig. 1. Illustrative bid price ladder for regulation and reserve power. Source: TenneT.

electricity can become a “waste good” like pollution. Production of electricity may not be reduced at short notice because of technical reasons (e.g., nuclear power plants are “must run” in the short term) or economic reasons (turning down a turbine may be very costly) or because of the inflexibility of contractual arrangements governing the sale of by-products. For example, generators that provide heating services to urban areas using the steam generated in electricity production cannot lower their electricity production because they would have to reduce their supply of heat to do so. Compared to other countries, cogeneration is a significant part of the Dutch electricity production. To summarize, because disposing of electricity is not simple or cheap, TenneT sometimes pays to get rid of the surplus and demands compensation to receive power.

RRPSs supplying positive power receive the positive power dispatch price, RRPSs supplying negative power pay the negative power dispatch price. The price for an imbalance transaction between TenneT and a PRP is more complex and contains both an energy and incentive component. The energy component depends on several factors, mainly on whether the PRP purchases or sells electricity to the system, and whether TenneT faces a surplus or a shortfall within the PTU (which in turn is determined by the positions of all the PRPs taken together over the PTU). The other component of the price on imbalance transactions with PRPs is the “incentive component,” which raises the price paid by a PRP and lowers the price received by a PRP. The precise regulations are given in [TenneT \(2001a\)](#) and have been shortly summarized in the next paragraph.

As for the energy component, a PRP receiving electricity pays the TenneT take price; a PRP supplying electricity receives the TenneT give price. For convenience, [Table 1](#) summarizes the determination of the TenneT give price and take price. If TenneT dispatches only positive power within the PTU, power transactions between TenneT and PRPs are billed at the “upward regulation price” (equal to the positive power dispatch price) regardless of whether the PRP supplies or consumes power. If TenneT dispatches only negative power within the PTU, PRPs pay and receive the “downward regulation price” (equal to the negative power dispatch price). If TenneT dispatches both positive and negative power within the PTU (also called double-sided regulation), TenneT pays the PRPs the downward regulation price for the power it purchases from the PRPs and charges the upward regulation price for the power it sells to the PRPs. The slope of the bid price

Table 1

Determination of the TenneT give and take price for Programme Responsible Parties

PRPs transaction	TenneT transaction within the PTU		
	Only negative power	Only positive power	Positive and negative power
TenneT give price	Negative power dispatch price – Incentive component	Positive power dispatch price – Incentive component	Negative power dispatch price – Incentive component
TenneT take price	Negative power dispatch price+ Incentive component	Positive power dispatch price+ Incentive component	Positive power dispatch price+ Incentive component

When TenneT dispatches only positive or only negative power within the PTU, the difference between the two prices is the incentive component. When TenneT dispatches both positive and negative power, the two prices diverge even if the incentive component is zero.

ladder and the maximum amount of positive and negative power demanded by TenneT to balance the system determine the difference between the upward regulation price and the downward regulation price. Finally, when excess demand of some PRPs exactly matches the excess supply of other PRPs, no regulating or reserve power is called for. This is a very rare situation and can be neglected. The price governing energy transactions between TenneT and PRPs is then the average between the highest bid price for negative power and the lowest bid price for positive power and is called the “regulating price.”

The incentive component creates a spread between the TenneT give and TenneT take price. It is adjusted weekly, based on the state of the system during the previous weeks and is set one day before the start of the week (see also [TenneT, 2001a](#)). The incentive component briefly peaked to € 11 per MWh in the first weeks of 2001, but is now around € 0. On average, it fell from about € 2 per MWh in 2001 to about € 0.50 in 2002 and was around zero in 2003. This suggests that the incentive component played a major role only in the early stages of the imbalance market. However, increased trading on the imbalance market may raise the incentive component again. In fact, increasing the incentive component could provide an easy way to prevent gaming, that is, the willful creation of positive or negative imbalance.

With a zero incentive component, the spread between the TenneT give and take price is zero when TenneT regulates one-sided. The potentially high level of the spread when TenneT regulates both up and down during the PTU reflects the fundamental characteristics of electricity: non-storability and short-term inelastic final demand.

3. Data description

We collected prices and volumes on the day-ahead market and the real-time (or imbalance) market in The Netherlands between 01/01/2001 and 31/12/2003.⁴ Because prices on the imbalance market are given at a higher frequency than those on the day-ahead market (15 min versus 1 h), we construct hourly averages of imbalance prices to compare day-ahead and imbalance prices for a given hour. For example, the four imbalance prices for 00:00–00:14, 00:15–00:29, 00:30–00:44 and 00:45–00:59 are averaged to one imbalance price for hour 0. In this paper, we use the imbalance prices including the incentive component.

Tables 2 and 3 present summary statistics of the APX price, the TenneT give price and the TenneT take price for every year between 2001 and 2003 and for each hour of the day. Looking at different years may give insights on the maturation of the market, studying each hour of the day seems natural given the daily cycle characteristic for electricity demand. Typically, for an average hour, the imbalance price at which power can be withdrawn from the grid (the take price) is above the APX price and the price at which

⁴ Day-ahead prices and volumes are available on the website of the APX (www.apx.nl/marketresults.html), imbalance prices and volumes are available on the website of TenneT (www.tennet.nl/english/system_services/imbalance_price/ and www.tennet.nl/english/system_services/balance_information/system_balance.asp#0). Note the published volumes start 01-01-2002. We excluded days with daylight saving hours from the analysis (25/03/2001, 28/10/2001, 31/03/2002, 27/10/2002, 30/03/2003, 26/10/2003) to prevent having days with 23 or 25 h.

Table 2

Summary statistics of the TenneT give, APX and TenneT take prices (in €/MWh) for each year between 2001 and 2003 and over the whole period

	2001			2002			2003			2001–2003		
	Give	APX	Take	Give	APX	Take	Give	APX	Take	Give	APX	Take
Mean	28	34	49	19	30	34	35	47	56	27	37	46
SD	79	56	81	51	42	57	108	102	111	83	72	86
Skewness	4	12	4	7	7	5	8	11	8	8	13	7
Kurtosis	52	196	42	70	71	48	112	169	96	128	263	105
Min	-702	0	-634	-135	0	-135	-199	0	-199	-702	0	-634
Max	1334	1600	1334	1037	701	1037	1964	2000	1964	1964	2000	1964

We averaged the 15-min TenneT prices to 1-h prices to enable comparison with APX prices.

power can be supplied to the grid (the give price) is lower than the APX price. Of course, this does not mean that the take price is always above the APX price and the give price is always below the APX price as for example hour 11 shows. In particular, imbalance prices (both give and take) can be negative whereas prices are always positive on the APX because of the € 0.01 minimum for bids in this market. The existence of a lower bound

Table 3

Summary statistics of the TenneT give, APX and TenneT take prices (in €/MWh) for each hour of the day over the 2001–2003 period

Hour	Mean			SD			Skewness			Kurtosis			Min			Max		
	Give	APX	Take	Give	APX	Take	Give	APX	Take	Give	APX	Take	Give	APX	Take	Give	APX	Take
0	3	20	29	35	6	38	-2	1	2	62	3	15	-505	0	-237	375	55	395
1	4	15	21	31	5	37	3	0	3	108	1	63	-356	0	-336	546	37	566
2	8	13	17	26	5	28	-1	-1	0	47	0	37	-258	0	-238	340	28	360
3	9	13	14	33	5	33	-9	0	-8	158	0	140	-558	0	-538	284	28	304
4	9	13	14	30	5	30	-11	-1	-10	221	0	190	-642	0	-622	116	28	124
5	4	14	14	32	6	33	-6	0	-5	86	0	68	-522	0	-502	183	39	183
6	1	18	27	48	9	54	-2	0	-1	26	0	15	-522	0	-502	299	45	299
7	21	25	72	70	15	88	0	2	0	15	15	8	-654	0	-634	475	150	777
8	30	35	72	74	36	86	2	7	2	9	64	5	-317	0	-199	535	500	685
9	52	55	71	96	99	101	4	12	6	31	192	71	-310	0	-290	1293	2000	1733
10	55	63	66	113	102	114	7	8	6	72	103	66	-177	0	-157	1774	1600	1774
11	66	79	73	131	126	128	6	8	6	53	85	54	-215	0	-195	1784	1999	1784
12	45	56	54	105	95	106	8	11	7	95	178	91	-604	0	-584	1784	1800	1784
13	54	61	62	115	103	113	7	9	8	91	125	93	-187	0	-167	1963	1800	1963
14	42	51	50	107	82	107	9	9	9	122	133	120	-435	0	-415	1964	1600	1964
15	38	47	46	97	105	97	10	12	9	145	165	140	-357	0	-337	1842	1800	1842
16	36	43	51	103	90	108	11	13	10	185	219	156	-224	0	-150	1927	1799	1950
17	63	70	82	154	154	158	6	7	5	43	56	30	-360	0	-340	1869	1999	1718
18	35	48	54	82	71	86	5	6	4	32	39	24	-260	1	-166	775	800	795
19	34	36	53	63	33	67	1	6	2	28	58	11	-702	9	-237	544	489	564
20	18	32	41	52	22	57	1	8	1	20	110	13	-414	2	-394	478	400	498
21	17	26	42	47	9	50	-1	3	1	30	16	7	-555	0	-257	358	101	378
22	12	24	36	42	7	43	-3	1	1	57	4	10	-604	0	-327	276	61	276
23	3	23	45	40	8	56	0	2	2	19	9	5	-410	0	-131	237	79	448

We averaged the 15-min TenneT prices to 1-h prices to enable comparison with APX prices.

on APX prices is also reflected in a higher skewness compared to imbalance prices. The spread between the take price and the give price is sometimes larger than the give price itself. This contrasts with the situation typically observed in equity markets. The patterns in the spread on the imbalance market are linked to the particular physical characteristics of electricity, mainly its non-storability.

4. Testing for price differences between day-ahead and real-time markets

Before turning to the connection between the day-ahead market and the real-time market in more details, we look at the difference between the average of the TenneT give and take price (the “mid price”) and the APX price over the whole sample (see Table 4). The mean difference is not statistically different from zero. The median is well below the mean and the negative skewness confirms this asymmetry in the probability distribution. TenneT prices can become negative, while the APX price is always positive by construction. This could contribute to the negative skewness of the spread between the “mid price” and the APX price. However, the largest negative deviations (nearing about € 2000 per MWh) occurred when the APX prices reached historical heights in the summer of 2003 while imbalance prices, for some hours, hovered at more average levels. Market tensions during those times were due to record high temperatures and the fear that electricity producers might be obliged to curtail their supply to obey environmental regulations. Naturally, the reverse situation (fairly low APX prices and very high imbalance prices) can also occur, as is shown by the high level of the maximum spread in Table 4. Naturally, when differences between the mid price and the APX are very large, the APX is often below the give price or above the take price.

The mid price constitutes a concise indicator of imbalance prices for a given PTU, but it is not a tradable price and hence should not be used to gauge the profitability of trading strategies. The difference between the price at which traders can buy and that at which they sell electricity in the imbalance market over the same period, the bid-ask spread, will determine the profitability of trading strategies spanning the two markets.

To take advantage of the price differences between the APX and the imbalance market, a trader can follow two strategies. Strategy I consists of selling electricity on the APX and buying it on the imbalance market. The resulting profit per MWh is the APX price minus

Table 4
Summary statistics of the spread between the average of the TenneT take price and give price and the APX price (in €/MWh)

Average of TenneT take and give prices minus APX	
Mean	-0.02
<i>t</i> -Statistics	-0.04
Median	-6
Standard deviation	66
Skewness	-5
Kurtosis	192
Minimum	-1962
Maximum	1171

the TenneT take price. In strategy II, one buys electricity on the APX and sells it on the imbalance market; the profit per MWh is then the TenneT give price minus the APX price. We analyse the realized profits from implementing these two strategies over the whole period 2001–2003, over each individual year in the period and finally over each individual hour of the day. We cannot look at a finer granularity because an hour is the shortest time span for which electricity can be traded on the APX.

As shown in Table 5, in 26% of the time, neither strategy is profitable. Moreover, when one is profitable, its mean profits are much lower than the mean losses of the other. For example, when strategy I is profitable and strategy II is not, the mean profit of the former is € 29 per MWh while the mean loss of the latter is € 36 per MWh. Considering each strategy separately, strategy I generates losses only slightly more often than gains (54% versus 46%) but when they occur, the losses are on average much higher than the gains (€ 42 per MWh versus € 29 per MWh). This results in a negative average profit for strategy I. Strategy II generates losses much more often than gains (73% versus 27%). This also results in a negative profit for this strategy, even though the gains when they occur are larger than the losses (€ 44 per MWh versus € 29 per MWh). While both strategies deliver similar average negative profit (about € 9 per MWh), the relative frequency of gains and losses and the relative size of the conditional mean of gains and losses are different across the two strategies. This is reflected in the skewness of the two profits.

In the period 2002–2003, TenneT regulated both up and down during the same PTU only 34% of the time (see Table 6). It regulated exclusively up 20% of the time and exclusively down 46% of the time. In some rare instances TenneT provided neither positive nor negative power. On an hourly frequency already 63% of the hours have at least one PTU with double-sided regulation.

Looking at the conditional means, we see that positive profits are typically associated with one-sided TenneT regulation when our strategy has an opposite position in the imbalance market compared to the system state. Not surprisingly, losses appear with double-sided regulation. One way to have a profitable strategy would thus be to predict the state of the system for a specific hour during the next day while avoiding hours with

Table 5

Probability of the TenneT give and take prices to be below or above the APX price and conditional mean of the profit for each case (in €/MWh)

		APX >= take (Gain for strategy I)	APX < take (Loss for strategy I)	Total
Give >= APX Gain for strategy II	Probability	0%	27%	27%
	Cond Mean I	33	-62	-62
	Cond Mean II	15	44	44
Give < APX Gain for strategy II	Probability	46%	26%	73%
	Cond Mean I	29	-22	11
	Cond Mean II	-36	-18	-29
Total	Probability	46%	54%	100%
	Cond Mean I	29	-42	-9
	Cond Mean II	-36	14	-9

Note that strategy I is profitable 46% of the time with an average gain of € 29 per MWh in the case of a gain, and an average loss of € 42 per MWh. On average, both strategies lose € 9 per MWh.

Table 6

Actual TenneT regulation in the period 2002–2003 on PTU and hourly frequency together with a conditional mean of the profit for each case (in €/MWh)

	No regulation	System shortage	System surplus	Double-sided regulation	Total
Probability (PTU)	0%	20%	46%	34%	100%
Probability (h)	0%	9%	27%	63%	100%
Conditional mean I	***	−76	34	−14	−7
Conditional mean II	***	75	−35	−14	−11

We call the system short (long) for an hour if the system is short (long) in 4 subsequent PTUs. If there is one PTU with double-sided regulation, the hour is said to have double-sided regulation. There have been 19 PTUs with no regulation, but not 4 PTUs in a row. Therefore there are no conditional means for the state “No regulation.”

double-sided regulation. Such a superior forecasting ability seems difficult to acquire. The imbalance market is the mechanism market participants use to clear the discrepancies between the scheduled and actual levels of their consumption and production. Forecasting the state of the imbalance market requires predicting the forecast errors and unplanned outages of others.

In this paper, we only report results on conditioning on time, and not on economic or weather factors. Our goal is to search for an implementation period where a trading strategy was profitable *ex post*. The results are displayed in Tables 7 and 8 and described in the following two subsections.

4.1. Testing for price differences without taking into account the price impact of extra trading

We first assume that implementing either trading strategy does not change the price on the APX or on the imbalance market. Later we will quantify the impact of additional buy and sell orders on the APX and on the imbalance market. In this paper, we will not quantify the operational cost of trading, which certainly has a negative impact on the profitability of the trading strategies.

Table 7 clearly shows that implementing either strategy on a whole year time-span would result in a net loss. However, this does not preclude the possibility of (*ex post*) profitable trades on a finer time grid. Table 8 presents several summary statistics of the profits resulting from implementing each strategy at an hourly frequency: mean, *t*-statistics enabling us to test whether the average profit is statistically positive or negative, standard deviation, skewness, kurtosis, the minimum, the maximum and the 5% quantile. The 5% quantile of the profit distribution indicates that the likelihood to observe lower profits is 5% and is sometimes referred to as the 95% historical Value at Risk (VaR). Naturally, the profits so far in the left tail of the distribution are negative. We use the size of such losses as a measure of the risk of the trading strategies. Computation of the quantile is based directly on the data and does not assume normality.

At an hourly frequency (Table 8), the average profits of both trading strategies are never statistically positive at the 5% level except for strategy I for the time slot 11:00–11:59. However, the 5% quantile indicates a large possible loss.

Table 7

Summary statistics of profits for strategy I (APX–take) and strategy II (give–APX) for each year between 2001 and 2003 and over the whole period (in €/MWh)

Year	I: APX–take								II: Give–APX							
	Mean	<i>t</i> -Statistics	SD	Skew	Kurt	Min	Max	5%	Mean	<i>t</i> -Statistics	SD	Skew	Kurt	Min	Max	5%
2001	–15	–21.1	67	0	55	–767	1567	–127	–6	–8.7	62	–2	71	–1582	743	–49
2002	–4	–7.7	48	–1	21	–537	562	–74	–11	–24.0	43	1	34	–651	537	–48
2003	–9	–9.5	89	6	154	–1171	1962	–137	–11	–12.6	85	–7	191	–1970	1171	–86
2001–2003	–9	–21.7	70	4	150	–1171	1962	–119	–9	–23.2	66	–6	200	–1970	1171	–62

For each year, average profits are statistically negative at the 5% level.

Table 8
 Summary statistics of profits for strategy I (APX–take) and strategy II (give–APX) for each hour of the day over the 2001–2003 period (in €/MWh)

Hour	I: APX–take								II: give–APX							
	Mean	<i>t</i> -Statistics	SD	Skew	Kurt	Min	Max	5%	Mean	<i>t</i> -Statistics	SD	Skew	Kurt	Min	Max	5%
0	-9	-8.3	37	-2	17	-374	272	-77	-17	-15.7	35	-3	68	-535	354	-45
1	-5	-4.6	36	-3	66	-547	342	-41	-12	-12.9	31	3	110	-362	527	-43
2	-3	-4.0	27	0	39	-345	238	-32	-5	-6.9	26	-1	48	-258	325	-33
3	-2	-1.9	32	8	143	-289	538	-28	-4	-3.9	32	-9	159	-558	269	-31
4	-2	-1.8	29	10	196	-106	622	-31	-4	-4.4	29	-11	224	-642	98	-30
5	0	0.2	32	5	71	-158	502	-36	-10	-10.9	31	-6	84	-522	158	-38
6	-9	-5.7	51	1	17	-279	502	-100	-17	-11.9	47	-2	24	-522	279	-71
7	-47	-18.8	82	-1	11	-767	644	-184	-4	-2.0	67	0	16	-664	443	-89
8	-37	-15.7	78	-1	5	-472	479	-185	-6	-2.6	69	1	10	-597	465	-94
9	-16	-5.8	89	7	159	-460	1794	-174	-3	-1.2	90	-9	207	-1970	460	-64
10	-3	-1.1	92	2	80	-961	1511	-155	-9	-3.1	89	-3	102	-1576	961	-72
11	6	2.0	105	5	117	-1001	1949	-146	-13	-4.3	102	-5	130	-1949	1001	-93
12	2	0.6	93	5	135	-883	1776	-110	-11	-4.1	92	-5	142	-1776	883	-62
13	-1	-0.4	95	4	127	-1091	1770	-137	-7	-2.5	93	-4	139	-1770	1091	-72
14	1	0.4	76	-3	63	-1171	671	-106	-8	-3.8	74	3	71	-671	1171	-69
15	1	0.3	93	10	198	-634	1777	-92	-9	-3.1	93	-10	194	-1777	634	-48
16	-7	-3.8	63	0	23	-471	682	-114	-8	-4.4	58	-1	28	-682	350	-63
17	-13	-4.1	101	7	141	-559	1962	-163	-7	-2.5	96	-8	162	-1962	539	-79
18	-6	-2.9	67	0	19	-550	676	-122	-13	-7.0	62	-1	24	-676	530	-72
19	-17	-9.2	63	-2	15	-550	302	-145	-2	-1.4	59	0	33	-719	530	-49
20	-10	-5.7	55	0	15	-496	415	-100	-13	-8.8	50	0	22	-435	476	-58
21	-15	-10.3	49	-1	8	-377	257	-107	-9	-6.8	46	0	30	-568	357	-52
22	-12	-9.3	43	-1	9	-253	327	-89	-13	-10.1	41	-3	55	-609	253	-49
23	-21	-12.8	55	-2	5	-447	153	-139	-21	-17.3	40	-1	19	-435	197	-77

Strategy I is statistically positive at the 5% level in hour 11. However, the 5% quantile indicates a loss of over € 146 per MWh in 5% of the cases.

A 5% quantile of -146 indicates that the losses are above $\text{€ } 146$ per MWh 5% of the time. This can be seen as a high risk in the light of the relatively low mean profit ($\text{€ } 6$ per MWh).

For most of the hours, the average profits of both trading strategies are statistically negative (at the 5% level). In about 20% of the cases, the mean profit is not statistically different from zero. In short, positive average profits may occur due to a higher volatility during those time intervals rather than to a higher underlying profitability.

Besides, for each year, we also split the sample into months (resp. into days of the week) to see whether implementing the proposed trading strategies only during some months (resp. during some days of the week) could have generated positive profits. Each strategy still involves a single specific hour but we average the results for all the hours in a given subperiod (month or day of the week). Results are not reported in this paper. On a monthly level, the picture is blurred, with losses for both strategies in May, June, July, and October, and no clear structure for the other months. On a daily level, both strategies generate losses on average, except for 2 days in 2002 where strategy I yields low but non-negative average profit. However, the profit for these days is not statistically positive at the 5% level.

The analysis above suggests that the main problem with implementing a trading strategy is the extreme volatility of the profits. Another problem a trader must face is that implementing either strategy will move the market prices unfavourably. This is studied in the following subsection.

4.2. Taking the price impact of extra trading into account

So far, to compute the profits of both trading strategies, we assumed that the prices on the APX and the imbalance market would not react to extra trade. This simplifying assumption overstates the profits. For example, purchasing electricity on the APX and selling it on the imbalance market will tend to increase the APX price and lower the imbalance price. The APX publishes the bid–ask ladders on its website, which enables us to estimate the price impact of an extra long or short position on the APX. Because TenneT only publishes partial information on the bid–ask ladders (like the numbers on the left side of Fig. 1), we choose to estimate the slope of the supply curve (resp. the demand curve) using a regression approach, which we detail later. Following discussions with market practitioners, we decided to shift the supply and demand curves in each market by an amount between 1 and 50 MWh. Even though order sizes on the APX market are typically larger, 50 MWh is considered a fairly large volume on the imbalance market. Because our strategies span both markets, we use the 50-MWh threshold.

To evaluate the impact of extra trading on the APX, we shift demand and supply by including an additional purchase at the maximum price or an additional supply at the minimum price in the bid–ask ladders. In this way, we can calculate the new market-clearing prices for any additional quantity. APX allows block bidding (bids concerning several hours which can only be called together) but publishes only called blocks. Due to this missing information, we cannot measure the dampening effect of block bidding on the APX price. The effect on the market price of shifting either supply or demand on the

APX turns out to be rather proportional and amounts to about 7 Eurocents per extra MWh.⁵

To evaluate the impact of extra trading on imbalance prices, we estimate the slope of the demand and supply curves by regressing the TenneT give price and take price on the actual imbalance volume and on the APX price (to control factors that may affect the locus rather than the slope of the curves). Thus we have

$$\text{TenneT}_{\text{give}}(T) = 16.09 + 0.66 \times \text{APX}(t) + 0.33 \times \text{VOL}(t)$$

(0.46) (0.00) (0.00)

$$\text{TenneT}_{\text{take}}(T) = 35.69 + 0.66 \times \text{APX}(t) + 0.38 \times \text{VOL}(t)$$

(0.48) (0.01) (0.00)

where numbers in between brackets below the parameter estimates are their standard errors. We use APX and TenneT imbalance prices for the same delivery period. The coefficient of determination (“adjusted R^2 ”) is in both cases about 0.64. These regressions cover the period 2002–2003 as TenneT imbalance volumes are not available for the year 2001. All coefficients are statistically significant at the 5% level. Based on these regressions, we conclude that one additional MWh in the imbalance market leads to an increase of the TenneT take price of 38 Eurocents and a decrease of the TenneT give price of 33 Eurocents. We have tried to increase the adjusted R^2 via extra explanatory variables like weather variables or the result of implementing the strategy the day before and changing the functional form. We found that the equations above perform the best out of these options. Finally, note the imbalance volumes are only known ex post. As imbalance volumes are hard to forecast, we cannot use these regressions to forecast imbalance prices.

We have seen that profits from implementing a trading strategy, when positive, are rarely above a few Euros per MWh. The sensitivity analysis above shows that the (ex post) profits would disappear fast if the trading strategies were implemented. In this paper, we do not quantify the operational cost of trading. This confirms that there are no trading opportunities between the day-ahead and imbalance market in The Netherlands. This coincides with the official anti-gaming goal of the Dutch imbalance pricing system.

5. Discussion and conclusion

In this section, we look at the Dutch imbalance system in a broad perspective and discuss how this system could be further improved in the future. We then present our final conclusion on potentially profitable trading strategies between the day-ahead market and the real-time market in The Netherlands.

⁵ More precisely, the equilibrium price on the APX would have increased by about 7 Eurocents in 2001 and 2002 and by 9 Eurocents in 2003 for each extra MWh purchased. The price would have decreased by about 5 Eurocents in 2001 and 2002 and by 7 Eurocents in 2003 for each extra MWh sold.

The Second EU Benchmarking Report on the Implementation of the Internal Electricity and Gas Market (2003) compared the imbalance mechanisms across the EU and concluded that the difference between the system give and take price in The Netherlands was among the highest in the EU. The report noted that the large spread could be unfavourable to new entrants in the market, like retail companies without generation assets or large portfolios of customers (for which the average forecast error tends to be lower). Smeers (2004) also notes that the large spread could act as a barrier to entry. From this perspective, it is interesting to think whether the height of the TenneT imbalance prices or the spread between them can be reduced. On the other hand, high imbalance prices provide an economic incentive for investments in new flexible power plants, which are in the long term essential for guaranteeing the security of supply. Also, the *Third Benchmarking Report (2004)* describes the balancing conditions in The Netherlands as favourable for entry.

One way to decrease the imbalance prices is thought to be a change to the technical balancing of the system. Currently TenneT splits 15-min intervals into 4-s intervals and calls positive or negative power in each of these 4-s intervals. When fast regulation is required in any of the 4-s intervals, imbalance prices are high due to the requirements put on the power plants. The high incremental cost of adjusting their supply at short notice leads generators and other RRPSs to bid relatively low prices to supply negative power and relatively high prices to provide positive power. This creates a large spread between the take price and the give price when TenneT regulates both up and down in the same PTU. With intervals larger than 4 s, regulating would be presumably smoother leading to lower imbalance prices. The question as to whether the grid remains technically stable is currently investigated by KEMA Consulting in an assignment by TenneT.

Another way to decrease the imbalance prices was discussed by Harris et al. (2004) after an assignment by TenneT. They state (p. 21): “It is not currently TenneT’s role to reduce balancing costs by, for example, replacing relatively expensive regulating power with cheaper reserve offers. TenneT points out that demand uncertainties make it difficult to reduce system balancing costs, and could even result in increased costs. TenneT believes that the dispatch of reserve power on economic grounds would increase the number of PTUs with two-sided balancing, which is apparently unpopular with market participants.” Harris et al. modelled the case where reserve power is dispatched when it would yield a price reduction. With perfect foresight, they find balancing prices could reduce by 7%. In reality the impact will of course be significantly smaller depending on how well TenneT can forecast the imbalance volumes 15 min ahead. One possible side effect would be that power plants are withheld from the market to serve the reserve market, leading to an increase of forward prices.

The price setting in the double pricing system could become part of our discussion as well. The current Dutch imbalance pricing system is similar to the NETA, the New Energy Trade Agreement, which replaced in 2001 the “pool” system used by England and Wales since the deregulation in 1990. Imbalance volumes are also cleared using two prices: the System Buy Price is the price at which the ISO purchases electricity to make up for system shortfall and which is charged to the short parties. The System Sell Price is the price at which the ISO sells power to alleviate potential surplus of electricity. These two prices play roles similar to the TenneT take and give prices. In contrast with the Dutch system, the System Buy and Sell prices are based on the average bids for positive and negative

power in the imbalance market, and not the marginal bid. Besides, suppliers of positive (resp. negative) power in the imbalance market receive (resp. pay) their own bids only: contrary to the Dutch system, the imbalance market in England and Wales is based on a pay-as-bid or discriminatory auction. Despite these differences, it seems natural that our conclusion on the absence of profitable trading strategies would hold as well for the electricity markets in England and Wales. As further research, one could carry out a similar analysis to see whether this hypothesis is correct. However, there are more issues besides the anti-gaming requirement in an imbalance pricing system like for example the security of supply and the size of the market. The discussion whether the NETA imbalance pricing system would perform well in the Dutch electricity market lies therefore outside the scope of this paper.

In contrast, the PJM electricity market, covering some mid-Atlantic States, does not impose dual prices in the imbalance market. On PJM, the differences between the quantities which parties agree to exchange during the day-ahead market and the quantities actually exchanged on the real-time market are priced at the imbalance price. We refer the reader to the [PJM eMKT Users Guide \(2004\)](#) for more details. Hence, traders can actually lock in the spread between the day-ahead price and the real-time price by selling in the day-ahead market while never delivering. This is equivalent to purchasing on the real-time market the quantities one contracted to deliver during the day-ahead market. [Zhou et al. \(2003\)](#) even note that market participants in PJM are allowed to submit purely financial bids in order to trade between the day-ahead and the real-time markets.

PJM also differs from the Dutch market in other ways. PJM uses Local Marginal Pricing (LMP), which is not used in The Netherlands. The LMP corresponds to the lowest cost of generating electricity in a given area. PJM posts LMPs for each of the more than 1750 buses it controls. When the system is unconstrained, that is when electricity can be transferred freely on the grid, a single market-clearing price ensues. In contrast, network congestion may result in significant difference in LMPs due to so-called congestion charges. Introduction of LMP could be the next change to the Dutch imbalance pricing system. In a recent press release, see [DTe \(2004\)](#), the Dutch Office of Energy Regulation indicates its interest in a market coupling between The Netherlands and Germany, while they state APX is working on a market coupling with her Belgium and French partners (Elia and Powernext). They think that increasing the size of the electricity market may contribute to improve functioning of the market and increased effectiveness. We view this will be an interesting step towards one European electricity market.

We conclude that it is impossible to implement a profitable trading strategy between the day-ahead and imbalance markets in The Netherlands due to the dual price system and a significant reaction of market prices to extra trade. This contributes to fulfilling the official goal of the Dutch regulator of preventing gaming.

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