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Real-time versus day-ahead market power in a hydro-based electricity market

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Real-time versus day-ahead market power in a hydro-based electricity market*

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Abstract

We analyse in a theoretical framework the link between real-time and day-ahead market performance in a hydro-based and imperfectly competitive wholesale electricity market. Theoretical predictions of the model are tested on data from the Nordic power exchange, Nord Pool Spot (NPS). We reject the hypothesis that prices at NPS were at their competitive levels throughout the period under examination. The empirical approach uses equilibrium prices and quantities and does not rely on bid data nor on estimation of demand or marginal cost functions.

Key Words: Hydro power, market power, Nord Pool Spot.

JEL codes: D43, D92, L13, L94, Q41.

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1 Introduction

Wholesale electricity markets typically are concentrated: A small number of power companies control the bulk of generation capacity, transmission bottlenecks constrain import possibilities, and economical and political barriers limit large scale entry. Demand is insensitive to short term changes in prices because household consumption mostly responds to monthly or yearly price averages. Concentrated markets with price inelastic demand are susceptible to the exercise of market power whereby producers behave strategically to raise profits. The performance of liberalized electricity markets therefore poses a major concern to competition authorities and other market monitors throughout the world.

Hydro power stands for more than half of the annual electricity production in more than one third of the countries in the world (Førsund, 2007). A problem of evaluating market performance in electricity markets which rely heavily on hydro power stems from the fact that hydro marginal costs are problematic to estimate for outside observers. In a hydro power plant, the decision problem facing management is how much of the plant's reservoir to release today and how much to save for future production. The marginal production cost in a hydro power plant consists mainly of this opportunity cost of water, the so-called *water value*. The water value depends on management's expectations about the future value of the resource. Hence, it is impossible to infer directly whether a hydro power plant running below full capacity sets competitive prices or not.

We illustrate in a theoretical model the challenge of detecting market power in a hydro-based electricity market. Hydro power production is a resource extraction problem. Hence, the equilibrium condition is a generalization of the Hotelling rule, which in its most basic form states that the price of a natural resource evolves proportionally to the real interest rate of return, which we for simplicity set equal to zero. Imperfect competition and uncertainty imply that a firm in our setting equates expected marginal revenues across time instead of expected prices. By assumption, the firm maximizes expected utility and not expected profit. Its most important implication is that resource extraction is adjusted by a risk correction factor, the magnitude of which depends on the correlation between consumption and marginal revenue. In addition, resource extraction is limited by production and/or reservoir constraints. To isolate the effects of market power, one would therefore have to control for the technological constraints and the effects of risk aversion on output and prices.

Liberalized electricity markets consist of a collection of submarkets spread out across time. Typically, generation companies can sell production up front at the day-ahead market, or they can take contractual positions in the forward market. But they can also reserve capacity to the delivery date and sell their production closer to real-time at various balancing markets. A theoretical contribution of this paper is to recognize that firms' multi-market presence can be used to control for unobservable covariates when evaluating market performance.

First, production and reservoir constraints do not matter for the trade-off between selling a given volume of production planned for day $t+1$ in the day-ahead market at day t at price f^*_{t+1} or saving it for the next day and selling it in real-time market at day $t+1$ at expected price $E_t[p^*_{t+1}]$. How to distribute a given amount of production across markets represents a portfolio selection problem, the solution to which is given by the consumption CAPM (Blanchard and Fischer, 1989). Hence, the expected marginal revenue in the real-time market equals the marginal revenue in the day-ahead market at equilibrium, corrected for the covariance between consumption and marginal revenue in the real-time market. In a competitive market, a (weakly) risk-averse producer must on average receive a (weakly) higher price in the real-time market than the day-ahead market, $E_t[p^*_{t+1}] \geq f^*_{t+1}$, to be willing to postpone sales until the next day. A negative relationship would be inconsistent with perfect competition.

Second, the marginal value to a hydro power producer of withholding production from the real-time market at day t and releasing it on the real-time market at day $t+1$ depends on similar factors as the value of withholding sales from the day-ahead market at t and selling it on the real-time market at $t+1$ instead. In the theoretical model, therefore, any difference between the real-time price p^*_t at t and the day-ahead price f^*_{t+1} at t for delivery at $t+1$ can be attributed either to production/reservoir constraints or to market power. Real-time prices and day-ahead prices are both risk-adjusted, so any risk correction cancels out. To isolate market power, it remains to control for the technological constraints. Although these constraints are difficult to estimate, it is considerably easier for an outsider to gauge whether they are likely to become more or less severe from one day to the next. Electricity demand varies predictably across time. For example, consumption is systematically higher on Mondays than Sundays. Tighter expected production constraints at day $t+1$ drive up f^*_{t+1} relative to p^*_t in a competitive market. Hence, competitiveness implies that production changes between t and $t+1$ are positively related to the price difference $f^*_{t+1} - p^*_t$. A negative correlation would be a sign of imperfect competition.

We apply these theoretical results to evaluate market performance at the Nordic power exchange, Nord Pool Spot (NPS), for the period 2005 until 2009. The bulk of electricity production in the Nordic market is sold on NPS' day-ahead market, *Elspot*. Producers, retailers and large industrial consumers can then re-balance their positions on NPS' intra-day market, *Elbas*. Elbas, which we treat as our real-time market, opens straight after the day-ahead market has closed and is open until one hour prior to delivery.[1] We show that the Elbas price on average was above the Elspot price during the weekdays. But this relationship was reversed during the weekends, which is inconsistent with competitive prices. We also establish that the Elspot price for delivery day $t+1$ on average was higher (lower) than the Elbas price at day t if production at day $t+1$ was higher (lower) than the previous day. In summary, prices on NPS were largely consistent with markets being competitive, but we reject the hypothesis that prices were at their competitive levels throughout the period under examination. Specifically, we reject the hypothesis that prices were competitive during weekends.

2 Related literature

Johnsen (2001), Førsund (2007) and Mathiesen et al. (2013) derive optimal hydro production under assumptions of perfect competition or monopoly, whereas Crampes and Moreaux (2001), Garcia et al. (2001) and Hansen (2009) analyse oligopolistic competition. Our theoretical model extends these previous contributions by incorporating a day-ahead market in addition to the real-time market into a hydro power model of imperfect competition. Multi-market presence allows to derive predictions of market performance based upon the comparison of equilibrium outcomes across markets.

Bessembinder and Lemmon (2002) build a theoretical model of forward contracting in a competitive electricity market. Allaz and Vila (1993), Hughes and Kao (1997), Mahenc and Salanié (2004) and Holmberg (2011) consider forward contracting in imperfectly competitive wholesale electricity markets. These forward contracting models are static and therefore do not capture the intertemporal dimension of hydro power markets. The present context also allows imperfect competition at the forward (day-ahead) stage, whereas previous contributions assume forward markets to be perfectly competitive. Generation companies in our setting are run so as to maximize expected utility of the decision maker. This specification allows to consider the

[1] National balancing markets operated by the national transmission system operators (TSOs) subsequently take over. On top of the markets for physical delivery are the financial markets which allow market participants to hedge their production or consumption portfolios.

effects of risk aversion on market outcomes, but also encompasses risk neutral preference and therefore profit maximization as a special case.

The empirical literature for the most part has approached the problem of unobservable marginal costs by means of structural estimation techniques.[2] Wolak (2003) uses bid data at individual firm level from California whereas McRae and Wolak (2009) use similar bid data from New Zealand to estimate firm-specific residual demand elasticities. They show that prices are higher when residual demand is less elastic. These studies are exceptional because individual bid data are hard to come by in many electricity markets, the Nordic market being one of them. To account for the lack of firm-level data, some have placed additional structure on the econometric model in terms of functional form assumptions (mostly linear-quadratic) for the demand and the marginal cost of producing electricity. These studies often are based on the well-known Bresnahan-Lau model; see Bask et al. (2011) or Graf and Wozabal (2013) for recent examples. But the Bresnahan-Lau model is essentially static and cannot easily be modified to capture the intertemporal aspects of hydro power markets. Indeed, estimation results turn out to be sensitive to model specification; see e.g. Kim and Knittel (2006) for a critical evaluation.

Another strand of the literature explicitly accounts for intertemporality by building dynamic numerical models of the electricity market. Examples of simulation models in this vein are Bushnell (2003), Kauppi and Liski (2008), and Philpott et al. (2010). Because of their computational burdens, simulation models often need to take an aggregate market view. The Kauppi and Liski (2008) model, for example, treats the Nordic region as a single integrated market and has a weekly resolution. At these high aggregation levels, it is not possible to identify any exercise of market power at the local level arising from bottlenecks and short-term demand variations.

The empirical approach suggested in this paper has minimal data requirements in the sense that it only uses equilibrium prices and quantities. It does not rely on estimation of demand and supply functions because predictions are derived directly from the first-order conditions for expected utility maximization. This also means it is possible to investigate market performance at the local market level.

[2]It is less complicated to evaluate market performance in electricity markets which rely mainly on thermal energy because then reliable cost estimates based on engineering data for the individual power plants are readily available; see Wolfram (1999) and Borenstein et al. (2002) for classical applications to the UK and Californian electricity markets.

3 Theoretical analysis

3.1 The model

Technology Consider a power company with N reservoir-based hydro power facilities. Hydro power plant $n \in \mathcal{N} = \{1, ..., N\}$ produces q_{nt} MWh of energy day t by a linear production function. All direct costs associated with hydro production are fixed in the short run, hence the marginal hydro production cost is zero. There is an upper bound $\overline{q}_{nt}$ stemming from limits to capacity. We allow the upper bound to vary as a function of time because scheduled and unscheduled maintenance stops may cause capacity to fluctuate over time, so that real capacity $\overline{q}_{nt}$ sometimes is lower than nameplate capacity $\overline{q}_n$. Moreover, minimum flow requirements stemming from environmental constraints might create a positive lower bound $\underline{q}_n \geq 0$. Hence, at t production satisfies

$$q_{nt} \in [\underline{q}_n, \overline{q}_{nt}] \text{ for all } n \in \mathcal{N}. \tag{1}$$

Let r_{nt} be the reservoir level in hydro plant n at the end of day t and denote by i_{nt} reservoir inflow during t, both measured in MWh. The reservoir level in facility n evolves according to

$$r_{nt} \leq r_{n(t-1)} + i_{nt} - q_{nt} \tag{2}$$

Write $\overline{r}_n$ the maximum reservoir capacity. Each hydro power plant also has a minimal reservoir level $\underline{r}_n \geq 0$, which may be strictly positive for environmental (or other) reasons. At t, reservoirs satisfy also

$$r_{nt} \in [\underline{r}_n, \overline{r}_n] \text{ for all } n \in \mathcal{N}. \tag{3}$$

Firms are not allowed to spill water. Hence, we can write (1)-(3) as the merged reservoir constraints for all $n \in \mathcal{N}$:

$$\begin{aligned} r_{nt} \geq \quad & \underline{R}_n(r_{n(t-1)}) = \max\{\underline{r}_n; r_{n(t-1)} + i_{nt} - \overline{q}_{nt}\}, \\ r_{nt} \leq \quad & \overline{R}_n(r_{n(t-1)}) = \min\{\overline{r}_n; r_{n(t-1)} + i_{nt} - \underline{q}_n\}. \end{aligned} \tag{4}$$

At this point it is pertinent to discuss the assumption of linear hydro power technology. In day-to-day operations, water release is the only variable factor of production in a hydro power plant. Two factors affect the efficiency with which water is converted into electricity. First, as water is released from the dam, the height difference between the dam level and the turbine, the *gross head*, goes down. All else equal, a lower gross head implies lower production for given water release. For large reservoir power plants, day-to-day variations in release have negligible effects on the gross head, so this effect can safely be disregarded with the short time horizon considered here. Second, each turbine converts water into energy more or less efficiently depending on how much water is released through the turbine. Each turbine has an efficient operating span at which production increases linearly with water release. To achieve maximum efficiency over a wider production range, hydro power plants often have multiple turbines installed. Moreover, firms often operate multiple power plants. Thus, a linear specification, as considered in most of the theoretical literature (e.g. Crampes and Moreaux, 2001; Garcia et al., 2001; Førsund, 2007; Hansen, 2009) as well as simulation models (e.g. Bushnell, 2003; Kauppi and Liski, 2008; Philpott et al., 2010) seems a reasonable first approximation to normal day-to-day operations.

Markets The firm's aggregate production is $q_t = \sum_{n=1}^{N} q_{nt}$. Some of this, $z_{t-1} = \sum_{n=1}^{N} z_{n(t-1)}$, is sold in the the day-ahead market (at $t-1$) for delivery the subsequent day (at t). Residual demand in the day-ahead market equals $f_t = F_t(z_{t-1}, \mathbf{r}_{t-1})$ and is differentiable in both arguments. In general, residual demand depends also on the reservoir profile $\mathbf{r}_{t-1} = \{r_{n(t-1)}\}_{n=1}^{N}$. Rational competitors realize that $\mathbf{r}_{t-1}$ affects the future production decisions of the firm and adjust their own production correspondingly and thereby residual demand; see Crampes and Moreaux (2001). The rest of total production, $x_t = \sum_{n=1}^{N} x_{nt}$, is sold in the real-time market,, where the firm faces the differentiable residual inverse demand $p_t = P_t(x_t, z_{t-1}, \mathbf{r}_{t-1})$.

In the Nordic market, producers are required to submit to the TSO a production plan detailing how they aim to cover their positions in the day-ahead market. This requirement implies that aggregate bids in the day-ahead market cannot exceed aggregate production capacity:

$$z_t \in [\textstyle\sum_{n=1}^{N} \underline{q}_n, \sum_{n=1}^{N} \overline{q}_n] = [\underline{q}, \overline{q}]. \tag{5}$$

The decision maker of the firm enters t with capital k_{t-1} and consumes c_t, subject to the budget constraint

$$c_t + k_t \leq p_t x_t + f_t z_{t-1} + k_{t-1}. \tag{6}$$

For simplicity (this is innocuous), the risk-free interest rate between two periods is zero. All accounts pertaining to deliveries at t are settled and consumption takes place simultaneously, at the end of day t.

The decision problem The decision maker maximizes the expected utility of consumption (adding a period discount rate would not add much to the analysis for reasons discussed below)

$$U(c_t) + \sum_{s=1}^{\infty} E_t[U(c_{t+s})]$$

subject to the reservoir constraints (4), the bidding constraint (5) and the budget constraint (6). The subscripts on the expectations operator indicate that the decision is taken with regards to the information available at t. In this model the producer simultaneously bids into the day-ahead market for delivery the subsequent day, z_t, and the real-time market for delivery today, x_t. With this timing, the day-ahead price for delivery the subsequent day, f_{t+1}, and today's real-time price, p_t, are determined simultaneously. The utility function $U(\cdot)$ is assumed to be continuously differentiable, strictly increasing in consumption, weakly concave and satisfy the Inada conditions.

It is convenient to rewrite the maximization problem in terms of the problem of choosing a reservoir profile $\mathbf{r}_t$ for day t, how much to save for the subsequent day, k_t, and how much to commit to the subsequent day-ahead market, z_t. By virtue of the production relation

$$x_t = \underbrace{\sum_{n=1}^{N}(r_{n(t-1)} + i_{nt} - r_{nt})}_{q_t} - z_{t-1},$$

we can rewrite profit as a function of $\mathbf{r}_t$, z_{t-1} and $\mathbf{r}_{t-1}$:

$$\pi_t(\mathbf{r}_t, z_{t-1}, \mathbf{r}_{t-1}) = \Bigg[P_t(\underbrace{\sum_{n=1}^{N}(r_{n(t-1)} + i_{nt} - r_{nt}) - z_{t-1}}_{x_t}, z_{t-1}, \mathbf{r}_{t-1}) \times \\ (\underbrace{\sum_{n=1}^{N}(r_{n(t-1)} + i_{nt} - r_{nt}) - z_{t-1}}_{x_t}) \Bigg] + F_t(z_{t-1}, \mathbf{r}_{t-1}) z_{t-1}.$$

Non-satiation of consumption implies that the budget constraint (6) is binding. Consequently, the Bellman equation becomes

$$
\begin{aligned}
v_t(z_{t-1}, \mathbf{r}_{t-1}, k_{t-1}) = \quad & \max_{z_t, \mathbf{r}_t, k_t} \{U(\pi_t(\mathbf{r}_t, z_{t-1}, \mathbf{r}_{t-1}) + k_{t-1} - k_t) + \\
+ \quad & \textstyle\sum_{n=1}^{N} [\underline{\chi}_{nt}(r_{nt} - \underline{R}_n(r_{n(t-1)})) + \overline{\chi}_{nt}(\overline{R}_n(r_{n(t-1)}) - r_{nt})] \\
+ \quad & \underline{\lambda}_t(z_t - \underline{q}) + \overline{\lambda}_t(\overline{q} - z_t) + E_t[v_{t+1}(z_t, \mathbf{r}_t, k_t)]\},
\end{aligned}
$$

where $\underline{\chi}_{nt} \geq 0$ and $\overline{\chi}_{nt} \geq 0$ are the Kuhn-Tucker multipliers associated with the reservoir constraints (4), while $\underline{\lambda}_t$ and $\overline{\lambda}_t$ are the Kuhn-Tucker multipliers associated with the bidding constraint (5).

3.2 Optimum

Straightforward maximization with respect to the reservoir level in plant $n \in \mathcal{N}$ at date $t \geq$ 1yields the first-order condition (optimal values are indicated by asterisks)

$$
\begin{aligned}
& U'(c_t^*) \tfrac{\partial \pi_t(\mathbf{r}_t^*, z_{t-1}, \mathbf{r}_{t-1})}{\partial r_{nt}} + \underline{\chi}_{nt}^* - \overline{\chi}_{nt}^* \\
& \qquad + E_t[U'(c_{t+1}^*) \tfrac{\partial \pi_{t+1}(\mathbf{r}_{t+1}^*, z_t^*, \mathbf{r}_t^*)}{\partial r_{nt}} + \overline{\chi}_{n(t+1)}^* \overline{R}_n'(r_{nt}^*) - \underline{\chi}_{n(t+1)}^* \underline{R}_n'(r_{nt}^*)] = 0.
\end{aligned}
$$

To simplify notation, let $\partial P_{t+1}^*/\partial x_{t+1} = \partial P_{t+1}^*(x_{t+1}^*, z_t^*, \mathbf{r}_t^*)/\partial x_{t+1}$ and $\partial F_{t+1}^*/\partial r_{nt} = \partial F_{t+1}(z_t^*, \mathbf{r}_t^*)/\partial r_{nt}$. Rewrite the first-order condition for the optimal reservoir level as (for all $n \in \mathcal{N}$):

$$
\begin{aligned}
p_t^* + \tfrac{\partial P_t^*}{\partial x_t} x_t^* = \quad & \tfrac{E_t[U'(c_{t+1}^*)]}{U'(c_t^*)} E_t[p_{t+1}^* + (\tfrac{\partial P_{t+1}^*}{\partial x_{t+1}} + \tfrac{\partial P_{t+1}^*}{\partial r_{nt}}) x_{t+1}^* + \tfrac{\partial F_{t+1}^*}{\partial r_{nt}} z_t^*] \\
+ \quad & \tfrac{E_t[U'(c_{t+1}^*)]}{U'(c_t^*)} \tfrac{cov_t[U'(c_{t+1}^*), p_{t+1}^* + (\frac{\partial P_{t+1}^*}{\partial x_t} + \frac{\partial P_{t+1}^*}{\partial r_{nt}}) x_{t+1}^*]}{E_t[U'(c_{t+1}^*)]} \\
+ \quad & \tfrac{E_t[U'(c_{t+1}^*)]}{U'(c_t^*)} \tfrac{\underline{\chi}_{nt}^* - \overline{\chi}_{nt}^* - E_t[\underline{\chi}_{n(t+1)}^* \underline{R}_n'(r_{nt}^*) - \overline{\chi}_{n(t+1)}^* \overline{R}_n'(r_{nt}^*)]}{E_t[U'(c_{t+1}^*)]}.
\end{aligned}
\tag{7}
$$

This optimality condition is a generalization of the celebrated Hotelling rule which in its most basic form states that the price of a natural resource evolves proportionally to the real interest rate of return, which in this model is equal to zero. Hence, the simplest version of the Hotelling rule predicts price stability. Here, the firm which extracts the resource (water) potentially exercises market power. Market power and uncertainty imply that the firm equates expected marginal revenue across time. The assumption that the decision maker maximizes expected utility instead of expected profit implies that future profit is discounted by the intertemporal marginal rate of substitution. This is the first line in eq. (7) above. Uncertainty and risk aversion imply that resource extraction is adjusted by a risk correction factor, the magnitude of which depends the correlation between consumption and marginal revenue in the real-time market. Risk correction is the term in the second line above. Finally, resource extraction is limited by production and/or reservoir constraints captured by the shadow prices in the final line of eq. (7).

Consider next optimal bidding in the day-ahead market. By way of the first-order condition

$$E_t[U'(c^*_{t+1})\partial\pi_{t+1}(\mathbf{r}^*_t, z^*_t, k^*_t)/\partial z_t] + \underline{\lambda}^*_t - \overline{\lambda}^*_t = 0,$$

the optimal contract position z^*_t solves:

$$\begin{aligned} E_t[p^*_{t+1} + (\frac{\partial P^*_{t+1}}{\partial x_{t+1}} - \frac{\partial P^*_{t+1}}{\partial z_t})x^*_{t+1}] = & \quad f^*_{t+1} + \frac{\partial F^*_{t+1}}{\partial z_t} z^*_t - \frac{cov_t[U'(c^*_{t+1}), p^*_{t+1} + (\frac{\partial P^*_{t+1}}{\partial x_{t+1}} - \frac{\partial P^*_{t+1}}{\partial z_t})x^*_{t+1}]}{E_t[U'(c^*_{t+1})]} \\ & + \quad \frac{\underline{\lambda}^*_t - \overline{\lambda}^*_t}{E_t[U'(c^*_{t+1})]}. \end{aligned} \tag{8}$$

For any planned production level q_{t+1} the subsequent period, the producer has the choice between allocating some of it, z_t, to the day-ahead market and saving the rest, x_{t+1}, for the real-time market. This decision is equivalent to a portfolio selection problem, in which a share of wealth is invested up front with known return (the day-ahead market) and the rest in an asset with risky future return (the real-time market). Owing to expected utility maximization, the optimum is a variant of the consumption CAPM (Blanchard and Fischer, 1989), taking into account the possibility of market power and bidding restrictions in the day-ahead market: Expected marginal revenue in the real-time market equals marginal revenue in the day-ahead market, corrected by a risk-aversion factor which depends on the correlation between consumption and marginal revenue in the real-time market. Marginal revenue in the day-ahead market is deterministic here. In most deregulated electricity markets, producers bid in *supply functions*. Supply functions generally allow producers *ex ante* to optimally adapt production to every *ex post* realization of demand. It is as if demand was, indeed, deterministic; see e.g. Klemperer and Meyer (1989), Wolak (2003) and Holmberg (2008).

Finally, the first-order condition for the optimal savings decision gives the intertemporal marginal rate of substitution:[3]

$$\frac{E_t[U'(c^*_{t+1})]}{U'(c^*_t)} = 1. \tag{9}$$

[3]Optimal saving is why we can ignore discounting and why interest rates do not matter with the chosen time horizon. In general, optimal saving is equivalent to $\delta E_t[U'(c^*_{t+1})]/U'(c^*_t) = (1+r)^{-1} \approx 1$, where δ is the daily discount rate and r is the daily risk-free interest rate (which is very close to 0).

3.3 Theoretical predictions

Using (7) and (9) we obtain:

Proposition 1. *The equilibrium real-time price evolves according to*

$$\begin{aligned} p^*_{t+1} - p^*_t = & \frac{\partial P^*_t}{\partial x_t} x^*_t - E_t[(\frac{\partial P^*_{t+1}}{\partial x_{t+1}} + \frac{\partial P^*_{t+1}}{\partial r_{nt}}) x^*_{t+1}] - \frac{\partial F^*_{t+1}}{\partial r_{nt}} z^*_t - \frac{cov_t[U'(c^*_{t+1}),(\frac{\partial P^*_{t+1}}{\partial x_t} + \frac{\partial P^*_{t+1}}{\partial r_{nt}}) x^*_{t+1}]}{E_t[U'(c^*_{t+1})]} \\ + & \frac{\overline{\chi}^*_{nt} - \underline{\chi}^*_{nt} + E_t[\underline{\chi}^*_{n(t+1)} \underline{R}'_n(r^*_{nt})] - E_t[\overline{\chi}^*_{n(t+1)} \overline{R}'_n(r^*_{nt})]}{E_t[U'(c^*_{t+1})]} - \frac{cov_t[U'(c^*_{t+1}), p^*_{t+1}]}{E_t[U'(c^*_{t+1})]} + p^*_{t+1} - E_t[p^*_{t+1}]. \end{aligned} \quad (10)$$

Price fluctuations in real-time market have four potential explanations in this model: (i) the exercise of market power - the sum of the terms on the first line of (10); (ii) binding production and/or reservoir constraints - the first term on the second line of (10); (iii) risk aversion - the second term on the second line of (10); (iv) surprise events causing price shocks - the final term on the second line above. Under the assumption that price shocks are random with zero mean, one would still have to control for the technological constraints and the effects of risk aversion on prices to isolate the effects of market power in the real-time market.

Under normal market conditions a firm always bids a positive amount on the day-ahead market, i.e. $z^*_t > \underline{q}$, and reserves some capacity for future eventualities, i.e. $z^*_t < \overline{q}$. We can then rewrite the optimality condition (8) as:

Proposition 2. *Under normal market conditions ($\underline{q} < z^*_t < \overline{q}$), the equilibrium relation between the expected real-time price $E_t[p^*_{t+1}]$ and the day-ahead price f^*_{t+1} for delivery the same day ($t+1$) equals*

$$\begin{aligned} E_t[p^*_{t+1}] - f^*_{t+1} = & \frac{\partial F^*_{t+1}}{\partial z_t} z^*_t + E_t[(\frac{\partial P^*_{t+1}}{\partial z_t} - \frac{\partial P^*_{t+1}}{\partial x_{t+1}}) x^*_{t+1}] + \frac{cov_t[U'(c^*_{t+1}),(\frac{\partial P^*_{t+1}}{\partial z_t} - \frac{\partial P^*_{t+1}}{\partial x_{t+1}}) x^*_{t+1}]}{E_t[U'(c^*_{t+1})]} \\ - & \frac{cov_t[U'(c^*_{t+1}), p^*_{t+1}]}{E_t[U'(c^*_{t+1})]}. \end{aligned} \quad (11)$$

The production and reservoir constraints have disappeared compared with (10) because they do not affect the choice of market, day-ahead or real-time, on which to sell the planned production. If markets are competitive, then the terms on the first line vanish and all expected price differences are due to risk aversion:

$$E_t[p^*_{t+1}] - f^*_{t+1} = -\frac{cov_t[U'(c^*_{t+1}), p^*_{t+1}]}{E_t[U'(c^*_{t+1})]}. \quad (12)$$

A negative demand shock which decreases the equilibrium price, p^*_{t+1}, decreases also firm profit, $\pi^*_{t+1} = p^*_{t+1}x^*_{t+1} + f^*_{t+1}z^*_t$, and therefore consumption, c^*_{t+1}. Demand shocks thus imply a (weakly) negative covariance of p^*_{t+1} and $U'(c^*_{t+1})$. A negative supply shock, such as a production failure, decreases profit π^*_{t+1} and consumption c^*_{t+1}, but has no effect on the anticipated equilibrium price p^*_{t+1} under perfect competition. Under perfect competition, therefore, $cov_t[U'(c^*_{t+1}), p^*_{t+1}] < 0$ if the decision maker is risk averse and zero if she is risk neutral. Hence, we obtain our first null hypothesis:

Hypothesis 1. *Under normal market conditions and if the market is competitive, then* $E_t[p^*_{+1}] \geq f^*_{t+1}$.

This hypothesis states that a risk-averse decision maker on average must receive a higher price in the real-time market than the day-ahead market to be willing to take the risk of postponing sales until the next day in a competitive market.

Next, subtract (11) from (10) and rearrange:

Proposition 3. *The equilibrium relation between the real-time price* p^*_t *and the day-ahead price* f^*_{t+1}*, both determined at the same time (t) is:*

$$\begin{aligned} f^*_{t+1} - p^*_t = \quad & \frac{\partial P^*_t}{\partial x_t}x^*_t - E_t[(\frac{\partial P^*_{t+1}}{\partial z_t} + \frac{\partial P^*_{t+1}}{\partial r_{nt}})x^*_{t+1}] - (\frac{\partial F^*_{t+1}}{\partial z_t} + \frac{\partial F^*_{t+1}}{\partial r_{nt}})z^*_t - \frac{cov_t[U'(c^*_{t+1}),(\frac{\partial P^*_{t+1}}{\partial z_t} + \frac{\partial P^*_{t+1}}{\partial r_{nt}})x^*_{t+1}]}{E_t[U'(c^*_{t+1})]} \\ + \quad & \frac{\overline{\chi}^*_{nt} - \underline{\chi}^*_{nt} + E_t[\underline{\chi}^*_{n(t+1)}\underline{R}'_n(r^*_{nt})] - E_t[\overline{\chi}^*_{n(t+1)}\overline{R}'_n(r^*_{nt})]}{E_t[U'(c^*_{t+1})]}. \end{aligned} \tag{13}$$

Once we have appropriately controlled for current and expected production and reservoir constraints, any remaining price differences are necessarily due to the exercise of market power. This relation holds independently of the decision maker's attitude towards risk. Risk adjustment vanishes here because trading in the real-time market the following period represents the opportunity cost both of f^*_{t+1} and p^*_t. Notice also that price differences are realized and not expected because f^*_{t+1} and p^*_t are simultaneously determined (at t).

The estimation problem lies in the fact that shadow prices on the constraints are unobservable to outside observers and probably also correlated with the incentives to exercise market power. But notice that equilibrium prices depend upon the difference between current and expected shadow prices. While the level of the shadow prices is difficult to estimate, it could be easier to predict how they change over time. Aggregate electricity consumption displays predictable seasonal variation across the year, the week and over the course of the day.

Let current aggregate production be Q^*_t, and assume that producers are uncertain abut future supply, but certain that it will be higher the subsequent period than today: $Q^*_{t+1} > Q^*_t$. Higher production means that $q^*_{n(t+1)} > q^*_{nt}$ for one or more plants $n \in \mathcal{N}$. Assume that at least one of these plants is fully operational at t, so that $\overline{q}_{n(t+1)} \leq \overline{q}_{nt}$. Collecting inequalities yields

$$\overline{q}_{nt} \geq \overline{q}_{n(t+1)} \geq q^*_{n(t+1)} > q^*_{nt} \geq \underline{q}_n,$$

hence $r^*_{nt} > r^*_{n(t-1)} + i_{nt} - \overline{q}_{nt}$ and $r^*_{n(t+1)} < r^*_{nt} + i_{n(t+1)} - \underline{q}_n$. Assume also that current reservoir conditions are normal: $r^*_{nt} \in (\underline{r}_n, \overline{r}_n)$. In this case, $r^*_{nt} > \underline{R}_n(r^*_{n(t-1)})$ so that $\underline{\chi}^*_{nt} = 0$. If $r^*_{nt} + i_{n(t+1)} - \underline{q}_n \leq \overline{r}_n$, then $r^*_{n(t+1)} < \overline{R}(r^*_{nt})$, so that $\overline{\chi}^*_{n(t+1)} = 0$, but if $r^*_{nt} + i_{n(t+1)} - \underline{q}_n > \overline{r}_n$, then $\overline{R}'(r^*_{nt}) = 0$; see eq. (4). To summarize

$$\frac{\overline{\chi}^*_{nt} - \underline{\chi}^*_{nt} + E_t[\underline{\chi}^*_{n(t+1)} \underline{R}'_n(r^*_{nt})] - E_t[\overline{\chi}^*_{n(t+1)} \overline{R}'_n(r^*_{nt})]}{E_t[U'(c^*_{t+1})]} = \frac{\overline{\chi}^*_{nt} + E_t[\underline{\chi}^*_{n(t+1)} \underline{R}'_n(r^*_{nt})]}{E_t[U'(c^*_{t+1})]} \geq 0$$

in this case.

In the opposite case of producers ascertaining $Q^*_{t+1} < Q^*_t$:

$$\frac{\overline{\chi}^*_{nt} - \underline{\chi}^*_{nt} + E_t[\underline{\chi}^*_{n(t+1)} \underline{R}'_n(r^*_{nt})] - E_t[\overline{\chi}^*_{n(t+1)} \overline{R}'_n(r^*_{nt})]}{E_t[U'(c^*_{t+1})]} = -\frac{\underline{\chi}^*_{nt} + E_t[\overline{\chi}^*_{n(t+1)} \overline{R}'_n(r^*_{nt})]}{E_t[U'(c^*_{t+1})]} \leq 0$$

for some facility $n \in \mathcal{N}$ under normal production conditions ($\overline{q}_{n(t+1)} = \overline{q}_{nt} \geq q^*_{nt} > q^*_{n(t+1)} \geq \underline{q}_n$) and reservoir conditions ($r^*_{nt} \in (\underline{r}_n, \overline{r}_n)$).

The two above inequalities and the competitive equilibrium condition

$$f^*_{t+1} - p^*_t = \frac{\overline{\chi}^*_{nt} - \underline{\chi}^*_{nt} + E_t[\underline{\chi}^*_{n(t+1)} \underline{R}'_n(r^*_{nt})] - E_t[\overline{\chi}^*_{n(t+1)} \overline{R}'_n(r^*_{nt})]}{E_t[U'(c^*_{t+1})]}$$

yield:

Hypothesis 2. *Under normal production and reservoir conditions and if the market is competitive, then* $(Q^*_{t+1} - Q^*_t)(f^*_{t+1} - p^*_t) \geq 0$.

This hypothesis states that the day-ahead price tends to be higher (lower) than the current real-time price at competitive equilibrium if production is anticipated to increase (fall) the subsequent period. It corresponds to a peak-load pricing prediction applied to the day-ahead and real-time market.

4 Empirical analysis of the Nordic wholesale electricity market

4.1 Market description

The Nordic countries rely heavily on hydro power for electricity supply; see Table 1 below. Half of the installed generation capacity is hydro power, predominantly located in Norway and Sweden. Remaining generation capacity is for the most part Finnish and Swedish nuclear power and other thermal power - mainly combined heat and power and condensing power - in Denmark, Finland and Sweden. Wind power is a growing source of generation and is located primarily in Denmark and Sweden.

	Denmark	Finland	Norway	Sweden	Total
Hydro	0	3.2	30.7	16.2	50.1
Nuclear	0	2.7	0	9.4	12.1
Other thermal	9.8	11.1	1.1	8.0	30.0
Wind	4.2	0.3	0.7	3.7	8.9
Total	14.0	17.3	32.5	37.3	101.1

Table 1: Generation capacity (GWe) in 2012 (Source: NordREG, 2013)

Market concentration is fairly low on an aggregate level. There are five large producers, the largest of which, Vattenfall, owns roughly 16 per cent of installed production capacity (NordREG, 2013). However, aggregate numbers do not give the full picture of market concentration. Transmission bottlenecks on international connections often split the Nordic market into a subset of national markets; see more on this below. Four of the five largest producers are former national monopolies (the exception is E.ON) with generation assets concentrated to the home market. Hence, national market concentration is higher than what the aggregate numbers would seem to suggest. As an illustrative case in point, Vattenfall owns 37 per cent of Swedish generation capacity (NordREG, 2013). Joint ownership is widespread and creates collective market concentration. All Swedish nuclear power, for example, is jointly owned by the three large producers Vattenfall, Fortum and E.ON. Owing to local market concentration and joint ownership, there is reason to be concerned about market performance in the Nordic wholesale electricity market.

The cornerstone of the Nordic wholesale electricity market is the power exchange, Nord Pool

Spot (NPS).[4] In 2012, NPS traded 337.2 TWh electricity, which amounts to 77 per cent of total consumption in the Nordic countries that year.[5] NPS operates two main markets, the most important of which is the day-ahead market, *Elspot*. Elspot handled 99 per cent (334 TWh) of NPS' traded volume in 2012. The remaining 3.2 TWh were traded on the intra-day market, *Elbas*.[6] Elspot is divided into a number of smaller price areas, or zones, to account for international and domestic transmission bottlenecks. There are two price areas in Denmark and five in Norway, whereas Finland, Estonia, Latvia and Lithuania each constitute a separate price area for the time being. Sweden was a single price area until October 31, 2011, subsequent to which the country was split into four price areas.

We apply the methodology developed in the previous section to test for market power on NPS in price area Sweden. Elspot is our day-ahead market, and we treat Elbas as our real-time market. We examine the period January 1, 2005 until October 17, 2009, a data set that ends before Sweden was split into multiple price areas. We thus avoid any complications associated with the price area changes in Sweden.

4.2 The data

The day-ahead market - Elspot Participation at Elspot is voluntary, but only producers with local generation capacity, local industrial consumers and retailers who serve local end users are allowed to trade electricity there. Hence, Elspot is best described as a collection of regional markets (price areas) with inter-regional trade limited by the capacity of the transmission lines.

Market participants submit hourly demand or supply curves for physical delivery over the next day's 24-hour period. Bidding for the 24 periods of day t commences at noon, day $t-2$ and closes at noon, day $t-1$. Only the final bid curves prior to gate closure are binding. Hence, it is relevant to view a company's bid curves for the next 24 hours as one single observation.

NPS aggregates the individual supply and demand bids and clears the market by means of a uniform price for each hour and price area, taking into account the transmission constraints. The system price is the hourly clearing price for the entire market and would constitute the equilibrium price absent any transmission constraints. But as bottlenecks are frequent, it makes

[4]NPS traces its origin back to 1991 when Norway established a trading system for wholesale electricity as part of liberalizing its electricity sector. Sweden, Finland and Denmark subsequently joined to create what was then the first multinational power exchange in the world. NPS has subsequently integrated with Continental Europe and the Baltic countries.

[5]The rest of consumption stems from bilateral contracts between producers and industrial consumers or represents direct deliveries internal to vertically integrated producers and retailers.

[6]All numbers are from the NPS Annual Report 2013 which can be accessed at www.nordpoolspot.com.

sense to conduct the empirical analysis at price area level.

In summary, f_t^*, corresponds to the average hourly Elspot price in price area Sweden for delivery at day t . This corresponds to 1750 daily observations between January 1, 2005 and October 17, 2009. The prices we use are in Euro per Megawatt-hour (MWh). Elspot prices can be downloaded from Nord Pool Spot's website (www.nordpoolspot.com).

The real-time market - Elbas Elbas opens two hours after Elspot gate closure and closes one hour prior to physical delivery. Elbas resembles a regular stock market in the sense that trading is continuous. Continuous trading implies that the same product typically is traded at multiple prices over the course of the trading period as new market information arrives. For instance, the Elbas price most likely is close to the Elspot price shortly after the market has opened, but converges to the expected price at the balancing market as time evolves.

Owing to the comparatively low liquidity of Elbas, we calculate the hourly Elbas price by averaging the price for the entire trading period weighted by traded volume. The real-time price p_t^* then is the average hourly Elbas price at day t. Elbas clearing prices are available at request from NPS.

Additional variables Q_t^* is the average hourly production in price area Sweden at day t. Production data are available from the Swedish TSO, Svenska Kraftnät's, website (www.svk.se). As Figure 1 shows, average production is markedly lower on the weekends, corresponding to weekly consumption patterns.[7]

NPS also has a system for reporting failures in the electricity network called Urgent Market Messages (UMMs). In the regressions, we include a measure of UMMs indicating failures from coal, hydro or nuclear plants of at least 100 megawatts. In particular, we include counts of failure-hours that become known after the close of Elspot for any given day, thus they represent events that affect supply and potentially prices on the Elbas market, but not the Elspot market. We also assume that these failures are random events. As Figure 2 shows, the vast majority of days are free from major plant outages, though multiple outages in a day are still common, especially for coal and hydro plants.

[7] Calculations and statistical analysis are done using the R statistical programming language (R Core Team, 2013). All figures are drawn using the R package ggplot2 (Wickham, 2009).

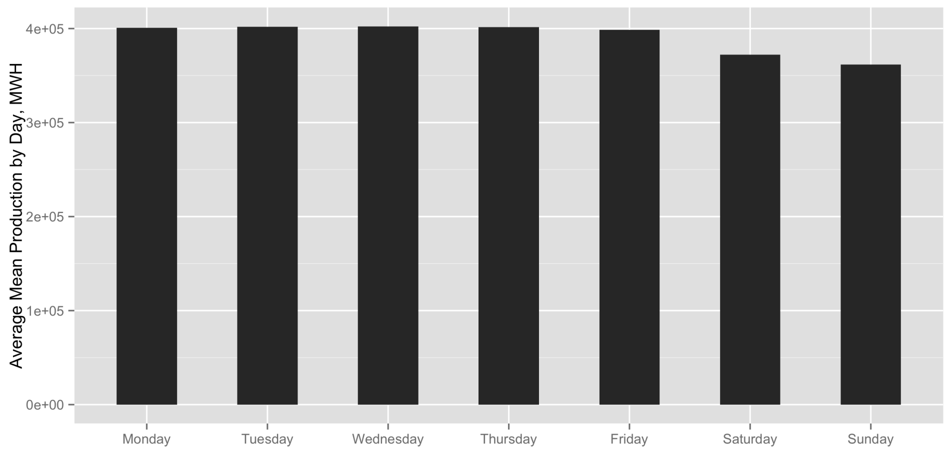

Figure 1: Average power production per day. Average production is substantially lower on Saturdays and Sundays, reflecting the normal weekly consumption pattern

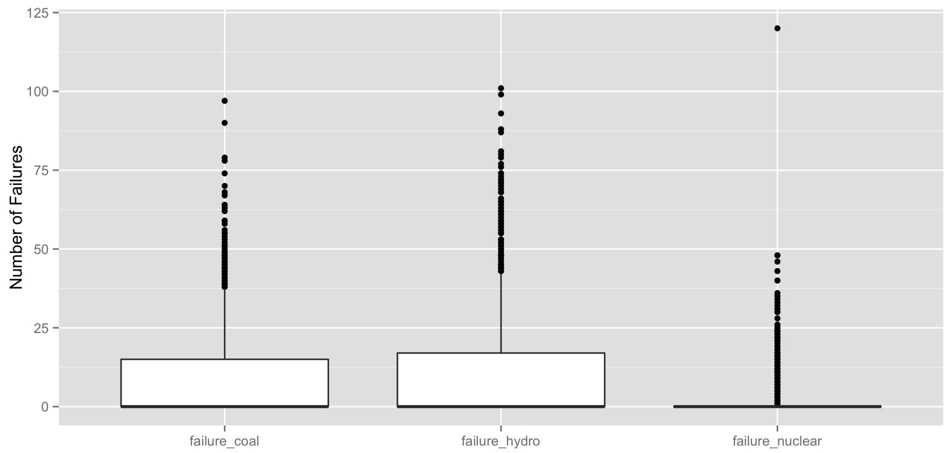

Figure 2: Box plot of the count of daily power plant failures in hours after the close of Elspot. The vast majority of observations have zero failures, however multiple failures in a day are not uncommon.

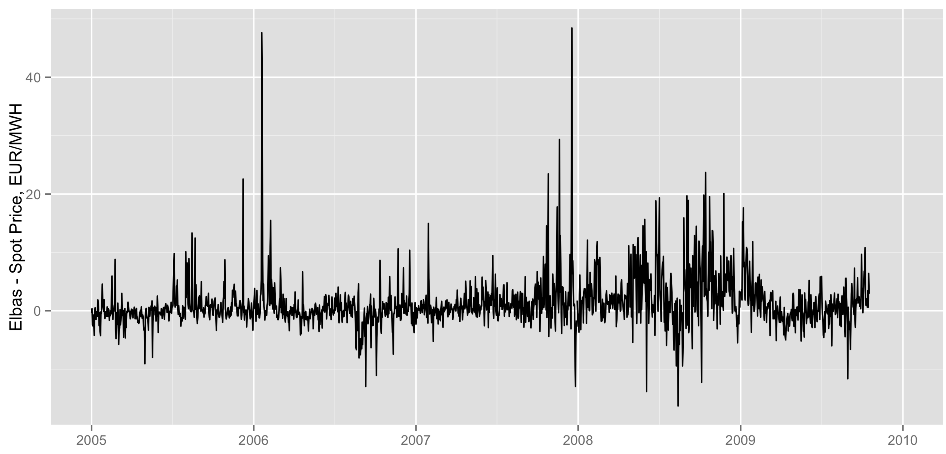

Figure 3: The series of the difference between average daily prices on Elbas less average daily prices on Elspot for delivery on day t. The series can be shown to be stationary, autocorrelated and heteroskedastic.

4.3 Results

Recalling Hypothesis 1, that on average the real-time price (Elbas) should be higher than the day-ahead price (Elspot) in a competitive market, Figure 3 shows the average difference between the prices on the two markets at any given day. The differences fluctuate around zero, while it appears that the Elbas price tends to be somewhat higher than the Elspot price when deviations occur. Any large divergences tend to quickly revert to the mean. Unsurprisingly then, the series can be shown to be stationary. However, the variance of the series appears to vary over time and the series can also be shown to be autocorrelated.

As a test of the first hypothesis we run a regression represented by equation (14) where the difference between the average Elbas price at day t, p_t^*, and the average Elspot price for delivery at day t (determined at day $t-1$), f_t^*, is our dependent variable. On the right hand side, we include an intercept term, α, while $\boldsymbol{UMM_t}$ represents a vector of variables for counts of coal, hydro and nuclear power plant failures. ϵ_t represents the error term. Hypothesis 1 is violated if and only if the intercept is negative and statistically significant.

$$p_t^* - f_t^* = \alpha + \boldsymbol{\beta UMM_t} + \epsilon_t \tag{14}$$

Table 1 reports the regression results for each separate day of the week.[8] The average Elbas price is higher than the average Elspot price all weekdays. The difference is statistically significant at least at the 5% level all weekdays except Wednesday. These results are consistent

[8]Table formatting was done using the R package texreg (Leifeld, 2013)

with (although not evidence of) competitive pricing during the weekdays. The intercept switches sign during the weekends when the average Elbas price is lower than the average Elspot price. This relationship is statistically insignificant on Saturdays but highly significant on Sundays. Hence, we reject the null hypothesis that Elspot and Elbas prices were competitive in price area Sweden during the entire sample period.

Production failures, in particular coal and hydro, tend to increase the Elbas price relative to the Elspot price. The price effect is somewhat larger during the weekdays. This not surprising given a wider availability of cheap reserve capacity during weekends.

	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
(Intercept)	0.95^{**}	1.06^{*}	0.42	0.98^{*}	1.01^{*}	-0.02	-0.71^{***}
	(0.36)	(0.48)	(0.36)	(0.43)	(0.41)	(0.22)	(0.20)
failure: coal	0.05^{*}	0.08^{**}	0.05^{**}	0.04	0.04^{*}	0.03^{*}	0.01
	(0.02)	(0.03)	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)
failure: nuclear	-0.02	0.02	0.03	0.02	0.03	0.00	0.01
	(0.04)	(0.04)	(0.04)	(0.04)	(0.04)	(0.02)	(0.02)
failure:hydro	0.04^{*}	0.01	0.05^{***}	0.05^{*}	0.02	0.00	0.01
	(0.02)	(0.02)	(0.01)	(0.02)	(0.02)	(0.01)	(0.01)
R^2	0.06	0.05	0.09	0.04	0.02	0.02	0.01
Adj. R^2	0.04	0.03	0.07	0.03	0.01	0.01	-0.01
Num. obs.	250	250	250	249	249	250	250

$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

Table 1: Table of regression results for tests of Hypothesis 1. Results are based on heteroskedasticity and autocorrelation consistent (HAC) estimates of standard errors.

To explore the second hypothesis we first create the series $S_t = (Q^*_{t+1} - Q^*_t)(f^*_{t+1} - p^*_t)$, the difference between production in day $t+1$ and production in day t multiplied by the Elspot price for delivery in day $t+1$ less the Elbas price for delivery in day t. The series is plotted in Figure 4. Again, the series can be shown to be stationary, however the series is autocorrelated and the variance of the series clearly varies over time (heteroskedasticity).

We use S_t as the left-hand side of the regression represented by equation (15), while on the right-hand side we again include an intercept term, α, a vector of variables, $\boldsymbol{UMM_t}$, representing power plant failures, and an error term ϵ_t. Separate regressions are run for each day of the week.

$$S_t = \alpha + \boldsymbol{\beta UMM_t} + \epsilon_t \tag{15}$$

Table 2 displays the regression results. These results are all consistent with competitive pricing. The intercept is of the expected sign for all weekdays and statistically significant at least at the 5% level all days except Tuesday. The intercept comes out with a much higher

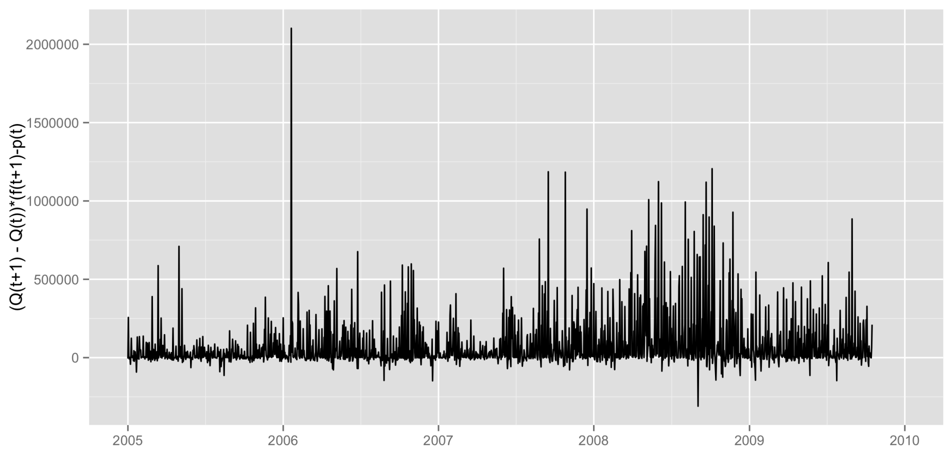

Figure 4: The constructed series used to evaluate Hypothesis 2. The series can be shown to be stationary, but autocorrelation and heteroskedasticity are present.

coefficient Friday and Sunday. In the first instance, this is due to a significant drop in production from Friday to Saturday and a correspondingly higher Elbas price on Friday than the Elspot price for delivery on Saturday. The Sunday coefficient picks up the production increase from Sunday to Monday, and the Elspot price for delivery on Monday is higher than the Elbas price on Sunday. What is interesting to note is that the price differences tend to be of the same sign as the realized production changes also for the other weekdays. Although average production changes are indiscernible from one weekday to the next, see Figure 1, the market seems to be able to predict whether total production will increase or decrease the subsequent day, and these anticipated production changes are priced in the market.

Failures for the most part have no significant effect on S_t. From a theoretical viewpoint, this should not be surprising in view of our assumption that f^*_{t+1} and p^*_t are set simultaneously at date t. The regression results indicate that there is some merit to this assumption.

4.4 Discussion of the results

Our estimations partially reject Hypothesis 1, but fail to reject Hypothesis 2. In summary, we reject the joint hypothesis that prices at NPS were at their competitive levels throughout the period under examination. The next question is whether the observed price differences are consistent with the exercise of market power. To simplify the discussion, assume that the producers are risk neutral and that the amount bid into the day-ahead market does not affect residual demand in the real-time market, i.e. $\frac{\partial P^*_{t+1}}{\partial z_t} = 0$. The optimality condition (11) then

	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
Intercept	22283.41**	5349.23	14176.55*	15347.73**	114622.60***	20161.79**	252346.44**
	(6709.20)	(4974.70)	(6294.20)	(5563.61)	(18815.52)	(6200.60)	(20022.30)
failure: coal	41.23	81.21	304.19	582.67	2230.29*	1069.03**	1691.55
	(335.81)	(267.96)	(333.61)	(299.79)	(980.23)	(385.83)	(1288.90)
failure: nuclear	−480.64	632.59	159.44	39.57	−633.06	486.97	−1185.97
	(794.89)	(444.22)	(635.84)	(526.80)	(2035.68)	(654.98)	(1590.39)
failure: hydro	−275.21	164.65	−117.50	43.33	878.97	184.16	649.79
	(319.52)	(178.89)	(252.61)	(262.66)	(896.16)	(341.16)	(1207.79)
R^2	0.00	0.01	0.00	0.02	0.02	0.04	0.01
Adj. R^2	-0.01	0.00	-0.01	0.00	0.01	0.02	0.00
Num. obs.	250	250	250	249	249	249	250

$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

Table 2: Table of regression results for tests of Hypothesis 2. Results are based on heteroskedasticity and autocorrelation consistent (HAC) estimates of standard errors.

becomes

$$E_t[p^*_{t+1}] - f^*_{t+1} = \frac{\partial F^*_{t+1}}{\partial z_t} z^*_t - E_t[\frac{\partial P^*_{t+1}}{\partial x_{t+1}} x^*_{t+1}].$$

Under the assumption that the average Elbas price is an unbiased estimate of the expected real-time price, the left-hand side of the above equation has been estimated to be strictly negative on Sundays. This is consistent with the exercise of market power in the day-ahead market on Saturdays (for delivery on Sundays). Transmission constraints often are non-binding during weekends because of low demand. Elspot therefore displays a large degree of integration between the different price areas on Saturdays and Sundays. Hence, one might expect competition on Elspot to be more intense during weekends. Suppose therefore that Elspot is competitive ($\frac{\partial F^*_{t+1}}{\partial z_t} = 0$). Since the price is falling in the quantity supplied ($\frac{\partial P^*_{t+1}}{\partial x_{t+1}} \leq 0$), the estimated relationship is consistent with producers being over-contracted in the real-time market ($x^*_{t+1} < 0$) so that they exercise buyer power with the purpose of decreasing the real-time price on Sundays.

The above equation also identifies a weakness of the diagnostic test we have proposed. The left-hand side of the above equation has been estimated to be strictly positive on weekdays. This is consistent with perfect competition and risk-aversion, but it is also consistent with Elspot being perfectly competitive and producers exercising seller power on Elbas. Given the limited number of participants in the real-time market and the relatively small volumes traded on Elbas, this is not an unlikely scenario. Hence, the tests proposed in this paper should only be seen as a first test of market performance and is no perfect substitute for more detailed tests based upon, say, observed bidding behaviour.

A possible explanation other than market power for the deviant prices could be that the average Elbas price produces a downward-biased estimate of the expected real-time price during weekends. This could be explained for example by a lower market liquidity on Saturdays and Sundays failing to deliver "correct" market prices. But if we return to Tables 1 and 2, we see that prices respond in a similar manner to reported production failures during the weekends as during the weekdays. For example, coal failures tend to drive up the Elbas price by nearly the same amount relative to the Elspot price on Saturdays and Sundays compared to the rest of the week. The only anomaly in the data is the average Elbas price being smaller than the average Elspot price on Sundays. It is not unreasonable to draw the conclusion that this can be traced back to rational bidding behaviour, rather than incorrect prices.

5 Conclusion

This paper has analysed in a theoretical framework the link between day-ahead and real-time market performance in a hydro-based wholesale electricity market. We have derived tests of market performance directly from the first-order conditions and applied them to evaluate the Nordic power exchange, Nord Pool Spot (NPS). Our results reject the null hypothesis that NPS was characterized by perfect competition in all markets throughout the period of investigation.

The informational requirements of the methodology are weak. We only use equilibrium prices and production. Individual bid data are not necessary, nor is it necessary to estimate demand and marginal cost functions. We control for risk aversion because the model builds upon expected utility maximization as its behavioral assumption.

Owing to its simplicity, the methodology necessarily brings with it some drawbacks. It is only a diagnostic test of whether the market can be considered competitive. In case of rejection, it is impossible to estimate markups without more detailed data. Also, we run the risk of underestimating market power because price relations consistent with perfect competition are also consistent with the exercise of market power. Hence, the methods proposed in this paper are by no means perfect substitutes for elaborate simulation models or estimation methods built upon detailed bid data. Rather, we see the methodology as a first and simple step in the analysis of the performance of hydro-based electricity markets.

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