

# **Nord Pool:**

## **A Power Market Without Market Power**

by

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Working Papers in Economics no 28  
Department of Economics  
Göteborg University

First version: August 1999  
Revised version: July 2000

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I would like to thank Dick Durevall, Håkan Locking, Serik Sagitov and Rick Wicks for invaluable advice and comments. I also want to thank Jan Foyn and other members of the Nord Pool staff for providing the data and for giving constructive advice. The Swedish Power Association, the Norwegian Meteorological Institute, and the Swedish Meteorological and Hydrological Institute have also been very supportive in providing data. Financial support from Göteborg Energi AB's Foundation for Research and Development is gratefully acknowledged.

### **Abstract**

Regulatory reform in the Nordic electricity-supply markets has resulted in a single integrated Nordic electricity market. This paper performs an econometric study of market power in the spot market of Nord Pool, the joint Nordic power exchange. I use a dynamic extension of the Bresnahan-Lau model, and weekly data for the period from 1996 through April 1999. To my knowledge, this is the first study of power markets that is not able to reject the hypothesis of perfect competition. The most likely reason for this absence of market power is the low ownership concentration in generation in the integrated Nordic electricity market.

JEL classification: L13, L51, L94, C32, C51, D41, D43

Keywords: electricity markets, deregulation, market power, spot market, power exchange, electricity pool, cointegration

## 1. Introduction

The last decade has seen the deregulation of several power markets around the world, and especially the US and EU electricity supply industries are undergoing a process of fundamental change. A central feature of most liberalised markets is a Power Exchange, PX, with an optional or mandatory spot market, and, as a complement, a market for financial instruments (futures, forwards and options). The spot market accommodates suppliers and consumers in an auction determining market clearing prices and quantities, while the financial market performs price hedging. In Europe today, there are PXs with spot markets in England and Wales, The Netherlands, Scandinavia (Denmark, Finland, Norway and Sweden), Spain and Switzerland.

The Scandinavian deregulation led to the establishment in 1993 of the joint Nordic Electricity Exchange, otherwise known as Nord Pool. In this paper a test is performed for market power in Nord Pool's spot market, Elspot.

To attract customers, a non-mandatory PX needs a spot market that creates confidence among its actual and potential participants. Effective competition in the spot market is important from several perspectives, directly for cost efficiency, transaction costs and the potentially large distributional effects of market power, indirectly for its impact on related financial markets. On the other hand, because of the very small short-run elasticity of demand market power has little impact on short-run demand or short-run allocative efficiency. Market power, however, distorts the least-cost utilisation of existing capacity, and if spot prices can be manipulated, fewer market agents will use the spot price as a reference when designing bilateral contracts, which would increase the share of bilateral contracts, leading to higher transaction costs. Just as for bilateral trade, the PX-based financial market is heavily dependent on a well functioning spot market to provide a relevant reference price. Any unnecessary uncertainty in the spot price, due to possible strategic pricing, lends an extra uncertainty to the financial contract prices. This leads to a diminished trade on the financial market which in turn decreases the possibility for all participants in the electricity market to hedge their contracts, thus reducing liquidity in the whole market. Research also indicates that the presence of a well functioning financial (futures) market might actually reduce market power on the spot market, see Coq and Skytte (1999). Thus, reduction of the volume of futures trade can in turn lead to an increase in market power on the spot market, making the situation even worse.

Moreover, electricity spot markets seems to be extra susceptible to strategic behaviour. While results in experimental economics suggests that 5 firms of equal size are enough to force prices close to marginal cost in a “normal” industry, the results by Rudkevich et al. (1998), in a game-theoretic framework, suggests that more than 30 firms of equal size are needed to ensure competitive pricing in an electricity spot market.

Against this background, there are good reasons to perform studies of market power in the power industry and to understand firm behaviour in competitive power markets. After the seminal study by Green and Newbery (1992), there has been a surge in studies on the behaviour of the liberalised power markets, especially England and Wales, but also Australia and California. While there have been many studies concerning market power in power markets, few of them have attempted to measure actual levels of, rather than potential for, market power<sup>1</sup>. Instead, most analyses are based on simulation models, investigating the potential for market power. This is, of course, due to the fact that, until a few years ago, liberalised power markets were virtually non-existent, so simulation was the only option.

The main contribution of this study, is an analysis of market power in the Nordic spot market. This is – to my knowledge – the first econometric study of market power in the whole Nordic spot market, i.e. at the so called *system level*, without transmission constraints, as well as the first econometric study of market power in a system dominated by hydropower. The market clearing volume and price are called the *system turnover* and the *system price* respectively, the latter which, because of transmission constraints, may deviate from so called *area prices*, which appear when transmission constraints are binding. (This system price is also the reference price for the financial market.) I apply a dynamic extension of the classical, static, Bresnahan-Lau (Bresnahan, 1982, and Lau, 1982) model for identification of market power. The hypothesis of no market power cannot be rejected at any reasonable significance level, and in fact this seems to be the first study that does not reject perfect competition in an electricity market.

A few other papers have considered the Nordic electricity market. Johnsen et al. (1999) analyses the Nordic market, focussing on transmission constraints and local market power. They do not attempt to measure actual market power at the system level, but instead

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<sup>1</sup> Brennan and Melanick (1998) model various bidding games in the Australian market; Borenstein and Bushnell (1999) simulate the potential for market power in the fully deregulated Californian market, expected to occur in 2001, while Borenstein et al. (1999b) measure actual market power in the Californian market, during the summer of 1998; Borenstein et al. (2000) and Cardell et al. (1997) both examine the sensitivity of market power in power markets due to transmission capacity constraints; Wolak and Patrick (1997) and Wolfram (1999) attempt to measure actual market power in the British spot market.

examine five Norwegian bidding areas,<sup>2</sup> finding evidence of market power only in one of them, Kristiansand, and limited evidence in another, Bergen. As a matter of fact, a presumed competitive *system price* provides the benchmark for their analysis.

Amundsen et al. (1998) also examine the Nordic market, evaluating the effects of free electricity-trade between the Nordic countries. Simulating both Cournot and perfect-competition equilibria, they find that with free trade the Cournot-equilibrium prices and the equilibrium prices under perfect competition are close, while the differences are much greater when no inter-country trade is allowed. Before liberalisation of the Swedish market, Andersson and Bergman (1995) in a Cournot model analysed the potential for market power in an isolated Swedish market, finding a very large potential.

In the next section I describe the Nordic power market. The model is presented in Section 3, and the data and variables are explained in Section 4. After integration and cointegration tests, the empirical model is specified in Section 5. The empirical results are presented in Section 6, while Section 7 summarizes and draws conclusions.

## 2. The Nordic Power Market

### 2.1 The Nordic Power Industry

Until quite recently Norway and Sweden were the actual market area for Nord Pool, and I will give a short outline of their power industries before describing Nord Pool itself.

Norwegian power industry is made up almost entirely of hydro, and more than 99.9% of all production comes from hydro-based generators. Due to the almost total reliance on hydropower, the between-year variations in total output are high. Total generation in Norway is about 100-120 TWh per year, with only two producers, Statkraft and Norsk Hydro, generating more than 10 TWh per year. The overall concentration is fairly small, with a Herfindahl index of about 0.12 and a CR2 of about 0.37<sup>3</sup>.

In contrast to Norway, the Swedish power industry has a high degree of market concentration, with a Herfindahl index of 0.33. Vattenfall and Sydkraft, the two largest producers, generate more than 70% of the total Swedish output of about 150 TWh and Vattenfall alone accounts for more than 50%. Sweden is also different from Norway in that

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<sup>2</sup> The bidding areas are Bergen, Kristiansand, Oslo, Trondheim, and Tromsø. The concept of bidding areas in the Nordic market is explained in Section 3.3.

<sup>3</sup> However, almost 50% of Statskrafts generation and 100% of Norsk Hydros is tied up in long-term contracts to electricity intensive industries. Adjusted for this, von der Fehr et al (1998) end up with a Herfindahl index of 0.07 for Norway.

about 50% of generation comes from nuclear power plants, about 45% from hydro plants and only about 5% from thermal (co-generation) plants.

Although there may be no direct link between concentration and market power, in an isolated Swedish market, we would expect substantial market power to be present; see Andersson and Bergman (1995) and Amundsen et al. (1998)<sup>4</sup>. Actually, however, the situation is one where Sweden and Norway can be considered as one market, in which Vattenfall's market share falls to about 30% and the Herfindahl index to 0.12. In the joint Nordic market, the question is much more open<sup>5</sup>.

## 2.2 *Nord Pool*

The markets of Nord Pool consist of the spot market, Elspot, which is the object of attention in this study, and the futures market, Eltermin, which is a purely financial (3 year horizon) market with futures, forwards and options. Nord Pool began operating officially in 1993 with Norway as the only area. Sweden joined in January 1996, Finland was fully integrated in March 1999. West-Denmark became a separate price area in July 1999. Border tariffs with Norway and Sweden reduce trade across the borders. Thus, without transmission constraints the spot price will be the same in Finland, Norway and Sweden but higher in Denmark.

The spot market is non-mandatory, and only about 25% of all traded electricity in Norway-Sweden is managed by Nord Pool; the rest is handled by bilateral contracts. Nevertheless, Nord Pool plays an important role, since trade at the margin takes place here, and the spot price of electricity is an important reference when determining prices in bilateral contracts.

## 2.3 *Market Procedures at Nord Pool*

Nord Pool's spot market is a one-hour, one-day-ahead double-auction market, and participants can place bids for each hour the next day until 12 hours before the market opens. Bids can be made valid for an entire week, or for several single days<sup>6</sup>.

To handle transmission constraints, the market is divided into several price, or bidding, areas. When the constraints are binding, prices differ in the bidding areas, with higher prices in deficit areas and lower prices in surplus areas. Sweden and Finland always consist of only one area each, whereas Norway may be divided into as many as five. (Internal

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<sup>4</sup> Borenstein et al. (1999a) discuss concentration measures and market power in electricity markets.

<sup>5</sup> See Hjalmarsson et al. (1999) for a description of the Nordic electricity supply industry and the reform process.

<sup>6</sup> For details, see Nord Pool (1998).

bottlenecks in the grids in Sweden, Finland and Denmark are handled by counter purchase.) Nord Pool distributes information to all market participants regarding which bidding areas will apply during the following week, based on data from the system operator in Norway, Statnett. Statnett also has the option to change the current week's bidding areas, should unexpected events occur. The overall system price and system turnover are the theoretical price and quantity that would have prevailed had there been no limitations in the grid. During most times of the year there are no, or very small, transmission constraints, so that deviations from the system price are usually small; see Figure 1 which shows the system price and Oslo and Stockholm prices.

**Insert Figure 1 about here.**

Actual bidding is done by participants submitting their bid curves to Nord Pool showing how much they are willing to buy or sell at different prices, and in what bidding area. The participants do not know the price of their own trades until all participants have submitted their bids and the equilibrium price has been calculated. When the price is calculated, each participant receives an exchange quantity which corresponds to their price-differentiated bid or offer.

In order to calculate the price, all the bids and offers are grouped together on an offer (sale) curve and a demand (purchase) curve. These curves represent Nord Pool's aggregated supply and demand, the market-clearing price is calculated at their intersection. This is the system price. If there are no transmission constraints, all bidding areas will be treated as one, and the system price will be its area price. If there are transmission constraints, however, then market clearing occur in each of the constrained areas, yielding separate *area prices*.

### **3. The Model**

Unlike with many other industries, cost functions in the power industry are rather transparent, and we can, at least in some cases, derive a good approximation of the marginal cost function. From this the Lerner index as a measure of any deviation from marginal cost pricing can be calculated, and thus of the magnitude of market power. This is done both by Borenstein et al. (1999b) in their examination of the California Electricity Market, and by Wolfram (1999) in her study of the British market.

Borenstein et al. (1999b) assume that there is no strategic use of hydropower resources. While a price-taking firm acting in a perfectly competitive market would try to allocate its hydro reservoirs (given reservoir constraints) in order to equalise *prices* across time periods, a strategic firm would attempt to equalise its *marginal revenue* across those time

periods<sup>7</sup>. While their assumption may very well be true for the Californian power market, it is of course not appropriate for the Nordic market dominated by hydro and nuclear<sup>8</sup>. They make their assumption due to difficulties in measuring opportunity cost when utilising hydropower. While the actual marginal (operating) cost in hydropower production is very close to zero, the opportunity cost, in foregone opportunity to produce electricity at some other time, might be considerable. This opportunity cost, however, is nearly impossible to observe or measure, and I will make no attempt to do so. Instead I turn to an econometric model for measuring and identifying market power.

### 3.1 The Classical Bresnahan-Lau Model

The model to test for market power which I will use is an extension of the classical Bresnahan-Lau (BL) model; see Bresnahan (1982) and Lau (1982). The BL model is based on the fact that profit-maximising firms will set their marginal cost equal to their perceived marginal revenue,  $MC=MR_p$ . Price-taking buyers are assumed. In perfect competition  $MR_p=P$ , but when market power is present we have  $MR_p<P$ . The model lets us identify the presence of market power, without knowing the demand function or the cost function *a priori*. Instead, the solution is to estimate the demand and supply relations.

The demand function can be represented as:

$$Q = D(P, Z, \mathbf{a}) + \mathbf{e} \quad (1)$$

where  $Q$  is quantity,  $P$  is price,  $Z$  is a vector of exogenous variables affecting the demand function,  $\mathbf{a}$  are the parameters to be estimated, and  $\mathbf{e}$  is the error term.

The supply function for price taking firms can be written as:

$$P = c(Q, W, \mathbf{b}) + \mathbf{h} \quad (2)$$

where  $W$  are exogenous variables affecting the supply function,  $\mathbf{b}$  are the parameters in the supply function,  $\mathbf{h}$  is the error term, and  $c(\cdot)$  is the marginal cost function.

However, when firms are *not* price takers, perceived marginal revenue, not price, will equal marginal cost. We now get a supply relation:

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<sup>7</sup> See Bushnell (1998) for an analysis of the strategic use of hydropower.

<sup>8</sup> Nuclear power is much less flexible and would be rather expensive to use for strategic purposes.



$$P = c(Q, W, \mathbf{b}) - I h(Q, Z, \mathbf{a}) + \mathbf{h} \quad (2')$$

where  $P+h(\cdot)$  is marginal revenue, and  $P+Ih(\cdot)$  is marginal revenue as perceived by the firm. Thus  $h(\cdot)$  is the semi-elasticity of market demand,  $Q/(Q/P)$ , and  $I$  is now a measure of market power. When  $I=1$  we have a monopoly, or a perfect cartel, and when  $I=0$  we have perfect competition.

The problem, of course, is to identify  $I$ . The demand function is always identified but not so the supply relation. Bresnahan (1982) shows that in order to identify the supply relation, we must introduce not only shift variables for the demand curve, but also variables that are able to rotate the demand curve. This is done by adding the vector  $PZ$  to the explanatory variables for the demand curve, where  $Z$  is a vector that also includes variables that are capable of changing the slope of the demand curve. The economic reasoning behind the inclusion of these interaction variables is that the variables in  $Z$  are assumed to be able to not only shift demand, but also to alter the price-elasticity of demand. This is in most circumstances a very reasonable assumption.

To see that  $I$  is indeed identified under these conditions, we look at the simplest form of a linear demand and supply relation. In this case we write (1) as:

$$Q = \mathbf{a}_0 + \mathbf{a}_p P + \mathbf{a}_z Z + \mathbf{a}_{pZ} PZ + \mathbf{e} \quad (3)$$

and if  $MC = \mathbf{b}_0 + \mathbf{b}_Q Q + \mathbf{b}_W W$  we write (2') as:

$$P = \mathbf{b}_0 + \mathbf{b}_Q Q + \mathbf{b}_W W - I \left[ \frac{Q}{\mathbf{a}_p + \mathbf{a}_{pZ} Z} \right] + \mathbf{h} \quad (4)$$

since  $MR = P + [Q/(\mathbf{a}_p + \mathbf{a}_{pZ} Z)]$ . Obviously  $I$  is now identified. The demand side is still identified, and by regarding  $\mathbf{a}_p$  and  $\mathbf{a}_{pZ}$  as known we can write  $Q^* = -Q/(\mathbf{a}_p + \mathbf{a}_{pZ} Z)$ . There are now two included endogenous variables,  $Q$  and  $Q^*$ , and two excluded exogenous variables,  $Z$  and  $PZ$ . Thus  $I$  is identified as the coefficient of  $Q^*$ .

The formal effect of including the rotation variable,  $PZ$ , in the demand equation, is that the demand function is not separable in  $Z$ . Lau (1982) shows that this condition is necessary and sufficient to identify  $\mathbf{I}$ .<sup>9</sup>

### 3.2 The Bresnahan-Lau Model in a Dynamic Framework

The classical BL model is static representing some kind of long-run equilibrium, whereas, when modelling markets, some sort of short run dynamics are assumed to be present<sup>10</sup>. Here I suggest a simple augmentation of the BL model by adding lagged values of the variables in the model; i.e. an autoregressive distributed lag (ADL) form of the BL model.<sup>11</sup> This will capture the short run dynamics of the model, and we will be able to compute the long-run solution also. For the estimation to be valid, this extension of the BL model requires that the included variables be stationary, or that we difference them in order to make them stationary. However, the differencing of variables removes the long-run information contained in them, and therefore the ECM framework should be used when the data permits. The data in this study is a mix of stationary and non-stationary variables, so the normal ADL form will be used for the demand function, and an ECM will be used for the supply relation.

The model is the following extension of (1) and (2) when these are in a linear form:

$$Q_t = \mathbf{a}_0 + \sum_{i=1}^k \mathbf{a}_{Q,i} Q_{t-i} + \sum_{i=0}^l \mathbf{a}_{P,i} P_{t-i} + \sum_{i=0}^m \mathbf{a}_{Z,i} Z_{t-i} + \sum_{i=0}^n \mathbf{a}_{PZ,i} PZ_{t-i} + \mathbf{e}_t \quad (5)$$

$$P_t = \mathbf{b}_0 + \sum_{i=1}^r \mathbf{b}_{P,i} P_{t-i} + \sum_{i=0}^s \mathbf{b}_{Q,i} Q_{t-i} + \sum_{i=0}^u \mathbf{b}_{W,i} W_{t-i} + \sum_{i=0}^v \mathbf{I}_i Q_{t-i}^* + \mathbf{h}_t \quad (6)$$

where  $Z$  and  $W$  are defined as above. In order to identify the supply relation we need the coefficients of  $P$  and  $PZ$  so that we can define  $Q^*$ . The obvious choice for these coefficients is the long-run, or cumulative- effects, parameters. These are derived by setting  $Q_t = Q_{t-i}$ ,

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<sup>9</sup> Given that the demand and cost functions are twice continuously differentiable.

<sup>10</sup> Steen and Salvanes (1999) propose a way to extend the BL model to incorporate these short-run market dynamics, and at the same time to also find the long run relation. Their solution to the problem lies in reformulating the BL model as an error correction model (ECM). This, however, must be seen as a special case, since we generally do not formulate an ECM unless we have a number of non-stationary cointegrated variables; especially, the dependent variable should be non-stationary for the ECM to make sense. In the case of stationary variables, the ECM is not a plausible model, due to the fact that the long-run stationarity that the error correction aims toward is, in a sense, always present, since we are dealing with stationary data.

<sup>11</sup> The ADL form is the general dynamic form and the error correction form can always be derived from it, as can be seen in any textbook on time series econometrics (e.g., Banerjee et al. 1993).

$P_t = P_{t-i}$ ,  $Z_t = Z_{t-i}$ ,  $PZ_t = PZ_{t-i}$ ,  $W_t = W_{t-i}$  and  $Q_t^* = Q_{t-i}^*$  for all relevant  $i$ , and solving for the long-run static relation of (5):

$$Q = \frac{\mathbf{a}_0}{1 - \sum_{i=1}^k \mathbf{a}_{Q,i}} + \mathbf{q}_P P + \mathbf{q}_Z Z + \mathbf{q}_{PZ} PZ \quad (7)$$

where

$$\mathbf{q}_P = \frac{\sum_{i=0}^l \mathbf{a}_{P,i}}{1 - \sum_{i=1}^k \mathbf{a}_{Q,i}}, \mathbf{q}_Z = \frac{\sum_{i=0}^m \mathbf{a}_{Z,i}}{1 - \sum_{i=1}^k \mathbf{a}_{Q,i}}, \mathbf{q}_{PZ} = \frac{\sum_{i=0}^n \mathbf{a}_{PZ,i}}{1 - \sum_{i=1}^k \mathbf{a}_{Q,i}} \quad (8)$$

We can now define

$$Q^* = Q / (\mathbf{q}_P + \mathbf{q}_{PZ} Z) \quad (9)$$

and the long-run supply relation becomes:

$$P = \frac{\mathbf{b}_0}{1 - \sum_{i=1}^r \mathbf{b}_{P,i}} + \mathbf{x}_Q Q + \mathbf{x}_W W + \Lambda Q^* \quad (10)$$

where

$$\mathbf{x}_Q = \frac{\sum_{i=0}^s \mathbf{b}_{Q,i}}{1 - \sum_{i=1}^r \mathbf{b}_{P,i}}, \mathbf{x}_W = \frac{\sum_{i=0}^u \mathbf{b}_{W,i}}{1 - \sum_{i=1}^r \mathbf{b}_{P,i}}, \Lambda = \frac{\sum_{i=0}^v \mathbf{l}_i}{1 - \sum_{i=1}^r \mathbf{b}_{P,i}} \quad (11)$$

$\Lambda$  is now the measure of market power in the long run. We should however be cautious when trying to determine market power in the short run. There is no obvious interpretation of the various  $\mathbf{l}_i$ 's. If the objective is to measure market power in the short run, the contemporaneous  $\mathbf{I}$  should probably be used as its estimate.

#### 4. Data Specification

The data used is weekly from Week 2, 1996, through Week 16, 1999.<sup>12</sup> While Nord Pool has been operating a spot market from 1993, it was not until January 1996 that Sweden joined the market, and this is thus the natural time to begin the study. Finland joined the market in 1998, but was not fully integrated until March 1999, when the border tariffs were removed.

Before that the system price referred only to Norway and Sweden. Therefore, the actual market area in the study is limited to Norway and Sweden,<sup>13</sup> and, when deriving the variables used for determining supply and demand, I use a weighted average of the Norwegian and Swedish data.

I use the system price, as defined in Section 2.3, as the price variable, denoted by  $P$ . All prices are in Norwegian crowns (NOK, USD1≈NOK 8.5). The amount of electricity traded is defined as the hypothetical turnover that would arise if there were no capacity limitations in the grid; i.e. system turnover is used as the quantity variable.

##### 4.1. The Demand Side

The two most obvious variables that affect Nordic electricity demand are temperature (denoted by  $T$ ) and the level of industrial production ( $Prod$ ). The length of the day from sunrise to sunset, which I call *day length* ( $D$ ) for short, as an indicator of how much electricity is needed for lighting, is also a natural choice (Johnsen, 1998). We might also consider some sort of substitute price, such as fuel-oil prices, but as Johnsen (1998) shows, this factor does not seem to matter.

The natural choice of rotation, or interaction variables, are the interactions between price and the above mentioned exogenous variables, i.e. price times temperature and price times day length, denoted by  $PT$  and  $PD$ , respectively. Johnsen (1998) in fact shows that both temperature and day length do have an effect on the price elasticity of demand. The interaction between price and industrial production might also be considered but, while there might be an interaction between these variables in the very long run, the hope to capture this effect during a three-year period must be considered futile, so I do not include it.

The temperature variable is calculated as a weighted average of Swedish and Norwegian average temperatures.<sup>14</sup> The Swedish and Norwegian average temperatures are in

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<sup>12</sup> In Scandinavia weeks are numbered from the beginning of the year to the end, with Week 1 starting on the first Monday of the year.

<sup>13</sup> The short period of Finnish integration should not be expected to substantially affect the results.

<sup>14</sup> The weights used are 0.6 for Sweden and 0.4 for Norway, which approximate the ratio between Swedish and Norwegian GNP. The same weights are used when calculating average industrial production.

turn calculated as the mean temperature of 11 Swedish cities and of 6 Norwegian cities, weighted by their respective population.<sup>15</sup>

Industrial production is measured as a weighted average of the Norwegian and Swedish industrial production indexes.<sup>16</sup> Since these indexes are only available on a monthly basis, and the rest of the data is on a weekly basis, a simple interpolation was used to derive weekly estimates of industrial activity. This was done by fitting an exponential function between each monthly observation, in order to get an approximately constant percentage change within each month. A simple method like this does not yield perfect results, but the variation in activity within months should be small and the benefit of having data on a weekly basis clearly outweighs any lack of accuracy.

Day length is simply a deterministic variable, defined as the time from sunrise to sunset in Göteborg. The choice of place has no consequence, since measuring day length somewhere else only induces a shift upwards or downwards in the variable.

#### *4.2. The Supply Side*

On the supply side we need to find an approximation of the marginal cost function and variables that might induce a shift in it. From theory<sup>17</sup> we know that the cost function for the power industry should have the general shape shown in Figure 2.

Quantities up to  $Q_1$  represent hydropower production, which has virtually no variable cost at all. Additional quantities from  $Q_1$  to  $Q_2$  represent production from nuclear power plants, which have a higher marginal cost than hydropower, but still fairly small, and more importantly, constant. The last curved part of the marginal cost curve represents residual power, coming from such sources as waste, bio fuel, coal or oil.

#### **Insert Figure 2 about here**

In order to define the supply relation, we must obtain an approximation of the marginal cost curve, as described above, and account for any factors that might induce a shift in it such as wages, or fuel prices: the price of coal or oil, or the cost of uranium for the nuclear plants. However, coal and uranium prices are very stable, and the oil price has not moved much over the period; besides, oil accounts for a very small part of the residual-power output in Scandinavia nowadays. Since the power industry is not labour-intensive, wages are also not expected to have much impact on overall production costs. Instead, we must look at

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<sup>15</sup> The Swedish cities are Karlstad, Hudiksvall, Göteborg, Östersund, Kiruna, Stockholm, Växjö, Visby, Sundsvall, Malmö, and Luleå. The Norwegian cities are Oslo, Bergen, Narvik, Tromsø, Bodö, and Stavanger.

<sup>16</sup> Not adjusted seasonally or otherwise.

the power industry from the perspective of Scandinavia, where hydropower accounts for about two-thirds of total power production. As discussed earlier, while hydropower has a very small actual marginal cost, it might indeed have a large and varying opportunity cost, in the sense that producing an extra amount of power means giving up the opportunity to store that amount of water in the water reservoirs, belonging to the power stations. The factors affecting this opportunity cost are the inflow of water to the reservoirs due to rainfall, snowfall and snow melting (denoted by  $I$ ), and how full they already are. However, while both these variables (inflow and available capacity) can be seen as shift variables for the supply relation, it might be better not to include them both, because while inflow to the reservoirs is an exogenous variable, the available capacity is an endogenous variable determined within the model<sup>18</sup>. In any case, lagged values of inflow can be used as additional shift variables to pick up most of the available-capacity information.

#### *4.3. Market Trends*

Since Nord Pool is not a mandatory pool, only a limited part of all power traded on the Nordic market is brokered there; the rest is handled through bilateral contracts. In the beginning of 1996, Nord Pool's market-share was about 10%, whereas by early 1999 it had risen to about 25%, of all power traded in Norway-Sweden.<sup>19</sup> There has thus been a great increase in the turnover at Nord Pool over the last couple of years, as more participants have entered the market.

When estimating the demand and supply relations this exogenous trend must somehow be adjusted for. The simplest way would be to include Nord Pool's market share as an explanatory variable for both demand and supply. A similar way is to regress system turnover at Nord Pool against the market-share trend. The residuals from this regression are used as de-trended values, in the demand and supply relation.<sup>20</sup> This approach gives us the opportunity to see how trade at Nord Pool would have varied over time, if its market share had been constant.

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<sup>17</sup> See for example Andersson (1997).

<sup>18</sup> If the reservoirs had been full during some periods and inflow of water had been lost due to this, inflow would have had to be treated as an endogenous variable. This, however, is very rare.

<sup>19</sup> When calculating Nord Pool's market share there are two obvious choices to choose between. Either we divide turnover at Nord Pool by total production or by total consumption within the market area. The two approaches yield similar but not identical results. I opt for the consumption approach here since this has the benefit of including net import to the area, which might be important in periods of extremely low or extremely high production.

After de-trending, the typical cyclical behaviour of turnover over the year is obvious (see Figure 3), with troughs in the summers and peaks in the winters. Since the residuals are used as detrended values, there is now negative turnover in certain periods, but this is only a matter of scale and has no impact on the results. Throughout the rest of the text, when estimating demand and supply, I will use the de-trended values of turnover, denoted by  $Q$ , unless otherwise stated.

**Insert Figure 3 about here**

Since Nord Pool is a spot market, much of the power traded there is due to unexpected demand fluctuations. Unexpected fluctuations are best met by residual power production,<sup>21</sup> which is not always in use, and by hydropower when available. Most of the large bilateral contracts, however, are based on hydro- and nuclear power, and I therefore make the assumption that all or at least the vast majority of residual power produced is traded on Nord Pool. But the amount of residual power produced, is always smaller than the total amount of power traded at Nord Pool, and while Nord Pool's market share has increased significantly over time, the production of residual power has not done so, which means that the percentage of residual power traded at Nord Pool has declined. Given the circumstances, this decrease must be seen as an exogenous process, which needs to be accounted for when estimating the supply relation.<sup>22</sup> This process is important, since residual power is generally more expensive than the base-load of hydro- and nuclear power, and a decrease in the percentage of residual power traded is likely to affect price. When estimating the supply relation, I therefore include the percentage of residual power traded at Nord Pool as an explanatory variable, referred to from now on as the residual-power trend, and denoted by  $R$ . Including two trends as regressors would lead to redundancy in the explanatory variables if the two trends were not clearly distinguishable from one another, but in this case they are in fact quite different.

## 5. Preliminary Tests and Empirical Model Specification

### 5.1 Integration Tests

Prior to specifying the empirical model, I test whether the variables included are stationary or not, but the actual data exhibit strong seasonal patterns which need to be adjusted for, before

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<sup>20</sup> These two approaches are not equivalent when lagged values of turnover are used as explanatory variables. Given that it is the de-trended turnover that is of interest, I consider the approach I am using to be the better one, under the circumstances.

<sup>21</sup> Import is included in my definition of residual power.

<sup>22</sup> Demand is unlikely to be affected.

testing for stationarity. I introduce weekly dummy variables,  $Week_i$ , and, for every relevant variable<sup>23</sup>, estimate the regression equation

$$y_t = \mathbf{a}_0 + \sum_{i=1}^{51} \mathbf{a}_i Week_i + \hat{y}_t \quad (12)$$

where  $\hat{y}_t$  is the regression residual. We may now view  $\hat{y}$  as the de-seasonalized values of  $y$ . Thereafter the ordinary augmented Dickey-Fuller test is performed on  $\hat{y}$ , using the BIC<sup>24</sup> criterion to determine the number of lags<sup>25</sup>.

All variables except system price, the interaction between price and day length, the interaction between price and temperature, and the residual power-trend appear to be stationary with test statistics significant at the 1% level. The test statistic for the interaction between price and temperature is significant at the 5% level but not at the 1% level, and I choose to treat this variable as non-stationary. The test results yield no surprises. Little has happened in industrial production the last three years and there is no *a priori* reason for turnover at Nord Pool to be non-stationary, once the market-share trend is removed and it has been adjusted for seasonality. Temperature, adjusted for seasonality, is almost by definition stationary, and inflow is merely the sum of rain- and snowfall. Neither price nor the residual power trend can be expected to be stationary, and the interaction variables there is little to say about.<sup>26</sup>

**Insert Table 1 about here.**

## 5.2. Cointegration Tests

Having some of the variables I(0) and some I(1) poses a problem when estimating the model. This leaves two alternatives, either trying to find cointegration relations between the non-stationary variables, or taking their first difference. As discussed earlier, differencing should not be used unless necessary, since it removes the long run information from the variables. I therefore choose the cointegration approach.

In the demand function, there are three variables I consider I(1): price, and the interaction terms between price and temperature and between price and day length. These are

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<sup>23</sup> Day length, deterministic variable, is not tested.

<sup>24</sup> The Schwarz-Bayesian information criterion, also abbreviated as SBC.

<sup>25</sup> See Enders (1995).

<sup>26</sup> Current research has not reached a conclusion regarding the behaviour of the product of an I(0) and an I(1) variable.



highly likely to be cointegrated and, as shown in Table 2 below, this proves to be the case. In the supply relation, price and the residual power trend are I(1). These two variables might also very well be cointegrated, since residual power is generally more expensive than base-load power, and if the relative supply of residual power is important enough when price is determined, then price and the residual-power trend might be cointegrated.

Using the Johansen procedure<sup>27</sup>, I estimate the cointegration relation between  $P$ ,  $PT$ , and  $PD$ . The null hypothesis of two cointegrating vectors cannot be rejected, at any reasonable significance level, using either the trace or the max test.

**Insert Table 2 about here.**

I then test the null hypothesis that the coefficients of  $PT$  and  $PD$  are zero in either of the two cointegration vectors. In both cases the null hypothesis is rejected, at all reasonable levels of significance, and the conclusion is that both  $PT$  and  $PD$  are part of the cointegrating space. This result is a necessary, though not sufficient, condition for market power to be identifiable.<sup>28</sup> Thus I call the test a separability test, to stress the importance this result has when determining whether the demand function is separable in either of the interaction variables, as will be seen in Section 6.1. Neither is it possible to exclude  $P$  from the cointegration space.

The results from the analysis of  $P$  and  $R$  are not as straightforward. Using the trace test, the null hypothesis of no cointegration vectors can be rejected at the 2.5% level.<sup>29</sup> However, the null hypothesis of one cointegration vector can also be rejected, at the 5% level, but not at the 2.5% level.<sup>30</sup> Given that I believe  $P$  and  $R$  to be non-stationary, I choose not to reject the null hypothesis of one cointegrating vector and instead reject the null hypothesis of no cointegrating vectors, given the strong significance in the trace test. This conclusion is supported by the fact of one large and one fairly small eigenvalue.

Thus, a cointegrating relation between  $P$ ,  $PT$ , and  $PD$  on the demand side, and between  $P$  and  $R$  on the supply side, is accepted.

**Insert Table 3 about here.**

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<sup>27</sup> See Banerjee et al. (1993).

<sup>28</sup> Lau's "impossibility theorem" states that market power is identifiable if and only if the demand function is not separable in at least one of the interaction variables.

<sup>29</sup> The critical values are: 2.5% -17.2, 1% -19.7.

<sup>30</sup> The critical values are: 2.5% -5.0, 1% -6.6.

### 5.3. The Empirical Model

Since all the variables are highly seasonal, we might expect to have to include some seasonal dummies to account for it. However, the explanatory variables show the same seasonality as the dependent variables, and I expect the explanatory variables to account for all the seasonality in the dependent variables, so I do not include any seasonal dummies.

Another issue to consider is whether there has been any structural break during the time period. Looking at the price series, one might certainly consider a change to have happened at the end of 1996 and the beginning of 1997, when there was a steep price fall. But 1996 was a very dry year, which has big consequences in a region where hydropower accounts for a majority of all power produced. Since I have included both inflow to the water reservoirs and the residual power trend, I am able to account for this price fall without resorting to any *ad hoc* dummy variables.

Assuming, then, a linear relationship in both the demand function and the supply relation, (except between price and output, where I expect marginal cost, as described in Figure 2, to be approximated by a quadratic relationship), demand and supply are specified as

$$Q_t = a_0 + \sum_{i=1}^k a_{Q,i} Q_{t-i} + \sum_{i=0}^k a_{P1,i} P1_{t-i} + \sum_{i=0}^k a_{P2,i} P2_{t-i} + \sum_{i=0}^k a_{T,i} T_{t-i} + \sum_{i=0}^k a_{D,i} D_{t-i} + \sum_{i=0}^k a_{Prod,i} Prod_{t-i} + e_t \quad (13)$$

$$\Delta P_t = b_0 + \sum_{i=1}^k b_{P,i} \Delta P_{t-i} + \sum_{i=0}^k b_{Q,i} Q_{t-i} + \sum_{i=0}^k b_{Q^2,i} Q_{t-i}^2 + \sum_{i=0}^k b_{I,i} I_{t-i} + \sum_{i=0}^k b_{R,i} \Delta R_{t-i} + \sum_{i=0}^k l_i Q_{t-i}^* + y R1_{t-1} + h_t \quad (14)$$

where  $P1$  is the first cointegrating vector between  $P$ ,  $PT$  and  $PD$ ,  $P2$  is the second, and  $R1$  is the first and only cointegrating vector between  $P$  and  $R$ <sup>31</sup>.

That is:

$$P1_t = P_t - 0.128PT_t \quad (15)$$

$$P2_t = P_t - 0.075PD_t \quad (16)$$

$$RI_t = P_t - 144.82R_t \quad (17)$$

Both demand and supply now consist entirely of stationary variables, and supply is formulated as an ECM, since the dependent variable,  $P$ , is non-stationary. Since  $Q^*$  is stationary, however, it is not included in the error-correction part of the model. Thus, there is not the same division between long-run and short-run measures of market power as in Steen and Salvanes (1999), but the short-run and long-run estimates can be calculated, as explained in Section 3.2.<sup>32</sup> The identification of market power is not yet ensured, but if the coefficients of either  $PI$  or  $P2$  are significant, market power will be identified.

To account for the possible simultaneity problem that always arises when dealing with demand and supply models, the system can be estimated using an instrumental variable technique, two-stage least-squares (2SLS); see Harvey (1990). The simultaneity problem comes from the inclusion of the endogenous variable  $P$  on the right-hand side of the demand equation, and from the inclusion of the endogenous variable  $Q$  on the right-hand side of the supply equation. The only time we do not face a simultaneity problem is with a totally inelastic supply or demand; neither case is expected here. As instruments for the demand equation I use inflow and lagged values of the explanatory variables. On the supply side, temperature, day length, and industrial production are used, together with lagged values of the explanatory variables in the supply equation.

## 6. Empirical Results

Using a general to specific approach, I first estimate (13) and (14), using the maximum number of lags considered plausible. Dealing with weekly data inevitably means that the time span covered by the lags must be much shorter than what is normal when dealing with monthly or quarterly data. It is, therefore, not realistic to hope to cover the more structural time-dependencies that might occur in variables. Instead, I expect to capture the short-run dynamics that occur from week to week. Five lags seems an appropriate starting point, as this

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<sup>31</sup> It might seem strange that the the *change* in price,  $DP_t$ , should depend on the *level* of other variables, but from an econometric point of view an autoregressive model in first difference can easily be rewritten as a model in level, and can thus be interpreted as such.

time length should be able to account for all the short-run dependencies that might be present in the variables. The next step is to see if this general model can be reduced to a more parsimonious one, using F-tests and the Schwarz criterion to find the most appropriate model. This process is outlined in Appendix 1 for the demand equation and in Appendix 2 for the supply equation. The models considered the most appropriate are shown below.

### 6.1 The Demand Function

The demand model shown in Table 4 is the parsimonious form of (13). Most of the lags included in the general form (using 5 lags) were not significant and have been removed.

**Insert Table 4 about here.**

Of the estimates of the parameters remaining in the model, all are highly significant except for the constant, with most of the t-statistics exceeding 3.0. Based on the Ljung-Box Q-statistics I reject both higher-order and lower-order autocorrelation in the residuals, which indicates that the model is well formulated. The  $\bar{R}^2$  statistic is also very high. The individual estimates reveal some peculiarities: Lag 4 of turnover, industrial production and the cointegrating relations,  $P1$  and  $P2$ , are all significant. It is probably not wise, however, to draw any strong conclusions from this evidence, since there is no *a priori* reason why lag 4 should be of importance when dealing with weekly data. Instead, it is better to view these as some kind of adjustment parameters, adjusting for any initial over- or under-reaction from the market. The contemporaneous impact of an increase in industrial production is positive, as expected, but the effect of industrial-production-lagged-once is negative, and then there is a positive effect again at lag 4. This pattern is probably due to expectations, and the fact that the market has a speculative side, albeit small.

With temperature, it's only the difference,  $\Delta T_t$ , which has any impact on demand. This should not be too surprising, since it is an optional spot market that we are considering. Unexpected changes should have a large impact on demand. Day-length, a measure of the demand for electricity used for lighting, is also highly significant.

With regard to the estimates for the cointegration vectors  $P1_t = P_t - 0.128PT_t$  and  $P2_t = P_t - 0.075PD_t$ , while lags 1 and 4 are highly significant, the contemporaneous value is not, which means that current price has no effect on current demand. There are at least two reasons for this. First of all, the data I am using is already aggregated to a weekly level from

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<sup>32</sup> Since the error-correction model can always be formulated as a normal ADL model, (14) is only a rewriting of the general form in (6).

hourly observations, which means that we might very well have a price-effect on demand in any period shorter than a week, but that the cumulative effect during the week is neutral. This would then mean that a price increase has both a positive and a negative effect on demand, a result which is not totally unsatisfactory, given that on the market there are speculative agents who might actually begin buying more when price increases, in the hope of further price increases. Second, few agents have the ability to monitor the market hour by hour, and thus probably make weekly plans for their purchases. They are then affected by last week's price, since they use this as a reference price.<sup>33</sup>

Lags 1 and 4 of  $P1_t$  and  $P2_t$  are both highly significant, but only the long-run estimate of  $P2$  is significant. This is very important, since, according to Lau's "impossibility theorem", market power is identified if and only if the demand function is not separable in both the interaction parameters. This amounts to at least one of the coefficients of  $PT$  or  $PD$  being significant. Since only  $P2$  is significant in the long run, only  $PD$  has a long-run effect. For  $PD$  to be significant, it is sufficient that  $P2$  is significant, since we have already proved, within the Johansen framework, that  $P2$  actually consists of  $P$  and  $PD$ , and does *not* exist if the interaction term is removed. Therefore, significance for  $P2$  implies significance for  $PD$ . The sign of the coefficient in front of  $P2_t$  is negative for lag 1, and positive for lag 4. The cumulative, and long-run, effect is negative, though. Despite any speculative elements, we expect price increases to have a negative effect on demand.

The interpretation of the signs of the interaction terms,  $PT$  and  $PD$ , are not so straightforward. These parameters are best interpreted from an elasticity perspective. The long-run own-price elasticity of electricity demand is defined as  $\varepsilon_{PP} = [q_P + q_{PD} \bar{D}] [\bar{P} / \bar{Q}_{actual}]$  where  $\bar{D}$  is average day-length,  $\bar{P}$  is the mean of the system price, and  $\bar{Q}_{actual}$  represents the mean of actual system turnover, not the de-trended.<sup>34</sup> Thus, when interpreting the signs of the interaction parameters, we should ask what effect temperature and day-length have on the price-elasticity of electricity demand. Reviewing Johnsen's (1998) results from his modelling of the Norwegian electricity market, we would expect the temperature effect to be negative and the day length effect to be positive. The reasoning behind this is that, although days are long in the summer, temperature is also relatively high, so that lighting probably accounts for a larger share of electricity consumption than in the winter. This leads to a larger sensitivity in demand the longer the day-length, *ceteris paribus*. The same argument holds for temperature,

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<sup>33</sup> Looking at the spot market in the short run, yesterday's price, and not the current price, will affect demand on a daily basis, since bids are made one-day-ahead, and selling and buying bids are made simultaneously.

though the time periods are now reversed. In the winter, when temperatures are low, heating accounts for a larger part of electricity demand than in the summer, indicating larger price sensitivity when temperatures are low, *ceteris paribus*. The long-run estimate of the interaction parameter  $PD$  is thus consistent with Johnsen's (1998) results.

Finally, I calculate the long-run price-elasticity of demand. This, however, should be understood with some caution, since the very concept of any long-run price-elasticity on a spot market is doubtful, since the spot market by its very nature is short-term. The estimate of the own-price elasticity,  $\epsilon_{PP}$ , is  $-0.039$ . As a comparison, Johnsen (1998) estimates the price elasticity to be between  $-0.05$  and  $-0.35$  for the sample period 1994:34 to 1996:52, but great changes have happened in the market since then<sup>35</sup>.

## 6.2. The Supply Relation

The parsimonious supply relation, which is derived from the general form in (14), using 5 lags, is presented in Table 5. It is estimated using 2SLS, with  $\Delta P_{t-1}$ ,  $\Delta I_{t-1}$ ,  $\Delta Q_{t-1}$ ,  $Q_{t-1}^*$ ,  $\Delta D_t$ ,  $\Delta T_t$  and  $\Delta Prod_t$  as instruments.  $Q_t^*$  is calculated as  $Q_t / (\mathbf{q}_p + \mathbf{q}_{PD} D_t)$  using the long-run parameters from the estimation of the demand function. The supply relation is estimated in an error-correction form where the first lag of the cointegration vector between price and the residual power trend,  $RI_{t-1}$ , constitutes the error-correction term. Most of the lagged variables included in the general model are removed, and the square of system turnover,  $Q_t^2$ , is removed completely. This is not an unlikely result, since we can probably find a good linear estimate of the cost curve shown in Figure 2, given that the actual data are all in the vicinity of  $Q_2$ , as defined there. Like the demand model, no autocorrelation is apparent in the residuals. While we have a much lower  $\bar{R}^2$ , 0.37, than in the demand model, this is due to the model being estimated in differences instead of in levels,<sup>36</sup> and should thus cause no concerns.

**Insert Table 5 about here.**

The only parameter that is not significant is the coefficient of  $Q_t^*$ . Thus no market power would appear to be present. While the coefficient of  $Q_t^*$  is supposed to be between 0 and  $-1$  (since no minus sign is included in the regression equation (14),  $\lambda$  changes sign), the fact that the estimate here is positive should be of no concern, since it is not significantly

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<sup>34</sup> Since  $PT$  is not significant in the long run, it does not affect long run price elasticity.

<sup>35</sup> For a discussion about low price-elasticities in electricity spot markets, see Newbery (1997), and Borenstein et al. (1999b).

<sup>36</sup> The  $\bar{R}^2$  statistic is not invariant to differencing and other such transformations of the data.

different from 0. Thus it should be interpreted as 0 and not as positive. The other estimates also reveal some interesting facts about the supply-side of the spot market. First of all,  $\Delta P_t$ , which is the dependent variable in the regression, does not seem to be an autoregressive process; none of the lags were significant as explanatory variables. It also turned out to be possible to reduce the 5 lags of  $Q_t$ ,  $I_t$ , and  $R_t$  to the first difference of these variables.  $\Delta Q_t$  has the obvious positive sign: An increase in inflow causes a price decrease, a natural albeit not entirely obvious result, since hydropower could be used quite strategically. As for  $\Delta R_t$ , there is a positive sign on the coefficient, which is unsurprising, since a larger percentage of residual power should either increase the price or leave it unaffected. The error-correction parameter, the coefficient in front of  $RI_{t-1}$ , is significant but small. There is only a 7% correction towards long-run equilibrium in any given week. This is only natural, though, since the data is on a weekly basis and little adjustment is to be expected.

## 7. Conclusions

Using a dynamic augmentation of the Bresnahan-Lau model, I examined the spot market for electricity on the Nordic Power exchange, Nord Pool, for any signs of market power. I used system price and system turnover, i.e., the price and turnover realised when no transmission constraints are binding, as my price and quantity variables.

The main result is that no market-power was apparent in the spot market; there was a clear rejection, and the relevant parameter was nowhere near significant, either in the short run or in the long run. However, since I used weekly aggregated data in the study (the actual data observations being on an hourly basis), there might be some market power in the very short run, most likely in the high demand hours. If it exists, this market power must be very small, though, since otherwise it would have shown up in the aggregated data.

Likewise, there might be some regional market power (of which Johnsen et al. (1999) found evidence) present but not detected in this study, since the various price areas that appear when transmission constraints are present, were not considered. The objective was to find out if Nord Pool functions properly, as a market place, and the relevant price at Nord Pool is the system price. This price does not directly account for transmission constraints, but since it is at the intersection of aggregate supply and aggregate demand, the firms submitting bids must have taken into consideration the possibility of transmission constraints, assuming that they acted rationally. This means that system price, in a sense, already includes expectations of capacity constraints. If firms do not consider transmission constraints when

submitting bids, regional market power would appear stochastically and would most likely be of no significance.

If we accept that there is no significant market-power in the Nord Pool area as a whole, the question is why. All studies performed on other power markets have found actual or at least potential market power. Wolfram (1999), for example, argues that British generators are not exercising as much market power as they are able to do, possibly because of the threat of further entry or fear of further regulations. Neither of these reasons is likely to affect the Nordic market, with a rather low concentration, and regulatory measures being an option only in the very long run. Considering market rules, one of the big differences between Nord Pool and the British market is that Nord Pool is a non-mandatory pool. Wolak (1997) argues that in an optional pool there will be agents with bilateral contracts, who are ready to offer in the spot market when prices rise enough. Thus, high bids in the spot market may be met by increased supply, rather than by higher prices.

The effect of having more or less hydropower in a power market is far from clear. While most studies argue that the more hydropower available, the less potential market power, nothing has actually been proved. Borenstein et al. (1999b) show that the potential for market power in the Californian market is higher, during periods when hydropower is scarce. However, it is far from obvious that the availability of hydropower has the same effect in the Nordic market, where hydropower is the dominant source, as it does in the Californian market, where hydropower makes up a much smaller part of total generation. Hence, while it might be tempting to explain the absence of market power at Nord Pool with the abundance of hydropower, this is merely speculation.

The absence of market power in Nord Pool is thus not easily explained by comparison with the British and Californian markets, where market power is present. While the British market has most of the indicators usually associated with market power, such as very high market-concentration, little hydropower, and a mandatory pool, this is not true for the Californian market, where, most importantly, market concentration is much lower than in the UK. The most natural conclusion to draw then, is that the very low market-concentration in Norway is enough to ensure competitive behaviour in the joint Norwegian-Swedish market, as the results of Andersson and Bergman (1995) and Amundsen et al (1998) also indicate.



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## Figures

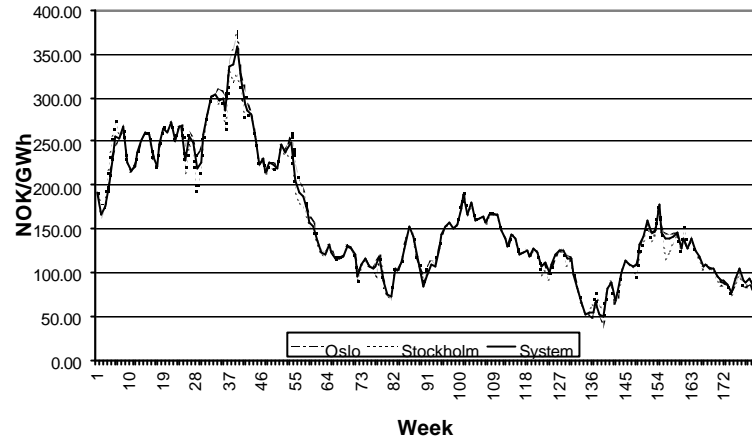


Figure 1. The system price, and the Oslo and Stockholm spot prices.

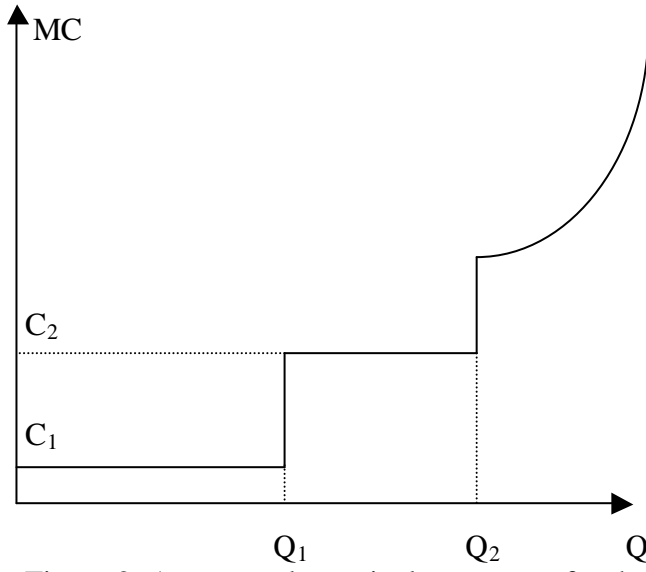


Figure 2. Aggregated marginal cost curve for the power industry.



Figure 3. De-trended system turnover.

## Tables

Table 1. Augmented Dickey-Fuller tests for order of integration

		I(0)	Lag	I(1)	Lag
<i>Q</i>	De-trended Turnover	-3.77**	1		
<i>P</i>	System Price	-1.21	0	-11.46**	0
<i>I</i>	Inflow	-5.96**	0		
<i>Prod</i>	Ind. Production Index	-3.70**	1		
<i>T</i>	Temperature	-8.64**	0		
<i>PT</i>	P*Temperature	-3.45*	0	-17.13**	0
<i>PD</i>	P*Daylength	-1.29	1	-10.81**	0
<i>R</i>	Residual Power Trend	-1.14	1	-12.59**	0

\*\* Significance at the 1% level. \* Significance at the 5% level.

Table 2. Cointegration analysis of  $P$ ,  $PT$  and  $PD$ . Seven lags were used when determining the cointegration vectors.

Eigenvalue	0.238	0.147	0.013
$H_0$ :	$r=0$	$r \leq 1$	$r \leq 2$
$\lambda_{\max}$	45.97**	25.97**	2.20
95% critical value	21.0	14.1	3.8
$\lambda_{\text{trace}}$	74.15**	28.17**	2.20
95% critical value	29.7	15.4	3.8
Standardised eigenvectors			
Variable	$P$	$PT$	$PD$
	1.00	-0.128	0.00
	1.00	0.00	-0.075
Test for separability			
$H_0: \beta_{1,PT}=0$	23.73**		
$H_0: \beta_{2,PD}=0$	23.73**		
$H_0: \beta_{1,P}=\beta_{2,P}=0$	38.95**		

\*\* Significance at the 1% level.



Table 3. Cointegration analysis of  $P$  and  $R$ . Two lags were used in the cointegration analysis.

Eigenvalue	0.149	0.047
$H_0$ :	$r=0$	$r \leq 1$
$\lambda_{\max}$	15.04*	4.52*
95% critical value	14.1	3.8
$\lambda_{\text{trace}}$	19.55**	4.52*
95% critical value	15.4	3.8

Variable	Standardised eigenvectors	
	$P$	$R$
	1.00	-144.818

\* Significance at the 5% level. \*\* Significance at the 1% level.

Table 4. OLS estimates of the parsimonious demand function; weekly data from 1996:02 to 1999:16. N=172.

Variable	Coefficient	Standard Error	t-value
Constant	72.326	54.541	1.326
$Q_{t-1}$	0.701	0.051	13.677
$Q_{t-4}$	0.105	0.040	2.620
$PI_{t-1}$	0.185	0.041	4.540
$PI_{t-4}$	-0.141	0.041	-3.484
$P2_{t-1}$	-1.194	0.283	-4.226
$P2_{t-4}$	0.653	0.263	2.488
$\Delta T_t$	-16.120	1.053	-15.303
$D_t$	-14.453	2.824	-5.118
$Prod_t$	6.988	1.198	5.835
$Prod_{t-1}$	-8.6438	1.346	-6.422
$Prod_{t-4}$	2.696	0.456	5.909
$\bar{R}^2$	0.98		
Sums of the estimates of the individual components in $PI$ and $P2$			
$P_{t-1}$	-1.009		
$PT_{t-1}$	-0.024		
$PD_{t-1}$	0.090		
$P_{t-4}$	0.512		
$PT_{t-4}$	0.018		
$PD_{t-4}$	-0.049		
Static long-run solution <sup>a</sup>			
Constant	372.2	285.9	
$PI$	0.226	0.223	
$P2$	-2.781	1.065	
$D$	-74.38	12.96	
$Prod$	5.353	1.856	
Estimates of the individual components of $P2$ in the long run			
$P$	-2.781	( $q_P$ )	
$PD$	0.210	( $q_{PD}$ )	
Ljung-Box Q-statistics		p-value	
Q(1)	0.039	0.84	
Q(2)	1.849	0.40	
Q(4)	4.077	0.40	
Q(8)	6.640	0.58	
Q(12)	7.274	0.84	
Q(24)	26.755	0.32	
Q(36)	33.152	0.60	

<sup>a</sup>Since  $\Delta T$  is equal to zero in the steady-state solution, it is not included.

Table 5. 2SLS estimates of the parsimonious supply relation; weekly data from 1996:02 to 1999:16. N=172.

Variable	Coefficient	Standard Error	t-value
Constant	8.949	4.287	2.088
$\Delta Q_t$	0.058	0.024	2.443
$\Delta I_t$	-0.002	0.0008	-2.604
$\Delta R_t$	95.211	16.388	5.810
$Q_t^*$	0.0001	0.004	0.036
$RI_{t-1}$	-0.069	0.032	-2.195
$\bar{R}^2$	0.37		

Estimates of the individual components in  $RI_{t-1}$

$P_{t-1}$	-0.069
$R_{t-1}$	9.992

Ljung-Box Q-statistics		p-value
Q(1)	0.234	0.63
Q(2)	0.420	0.81
Q(4)	0.660	0.96
Q(8)	3.898	0.87
Q(12)	10.578	0.57
Q(24)	18.770	0.76
Q(36)	30.476	0.73

## Appendix 1

### Derivation of the Demand Model

Table A2.1. F statistics and Schwarz criteria for sequential reduction of the general demand model to a parsimonious model.

Null hypothesis			Maintained hypothesis			
Model	K	SC	Model	Model	Model	Model
			1	2	3	4
1	28	7.59				
↓						
2	23	7.45	0.23 (5,139) [0.95]			
↓						
3	19	7.35	0.46 (9,139) [0.90]	0.77 (4,144) [0.55]		
↓						
4	14	7.22	0.60 (14,139) [0.86]	0.83 (9,144) [0.59]	0.87 (5,148) [0.49]	
↓						
5	12	7.17	0.64 (16,139) [0.84]	0.86 (11,144) [0.59]	0.91 (7,148) [0.50]	0.98 (2,153) [0.38]

Notes:

1. The first three columns report the model number, the number of unrestricted parameters, K, and the Schwarz criterion, SC. The three entries within a given block of numbers in the last 5 columns are: the F-statistic for testing the null hypothesis against the maintained hypothesis, the degrees of freedom for the F-statistics (in parentheses), and the tail probability of the F-statistics (in brackets).
2. Model 1 is the general demand model (13) with k=5 except that only one lag of day length,  $D$ , and temperature,  $T$ , are included, since it is not reasonable for greater lagged values of these variables to have any effect on contemporaneous demand. Model 2 is Model 1 excluding the fifth lag of  $Q$ ,  $P1$ ,  $P2$ , and  $Prod$ , and excluding the lagged variable of day length,  $D_{t-1}$ . Model 3 is Model 2 excluding the third lag of  $Q$ ,  $P1$ ,  $P2$ , and  $Prod$ . Model 4 is Model 3 excluding the second lag of  $Q$ ,  $P1$ ,  $P2$ , and  $Prod$ , and imposing the

restriction  $T_t = -T_{t-1}$ , that is,  $T_t$  and  $T_{t-1}$  are replaced by  $\Delta T_t$ . Model 5 is Model 4 excluding  $P1_t$  and  $P2_t$ .

3. While the demand model should be estimated using instrumental variables and 2SLS, the use of such a technique in a sequential reduction as above demands the same instruments in every step. This, however, poses a problem, since I use lagged values of the explanatory variables as instruments in the demand function. In practice, however, instrumental variables usually have a very small impact on the result, and I therefore perform the reduction of the model using normal OLS. Since Model 5 does not include any endogenous variables on the right-hand side, this model need not be estimated using 2SLS, and thus OLS is used also for the final model. The results from estimating Model 5, using the full sample, are shown in Table 4.

## Appendix 2

### Derivation of the Supply Model

Table A3.1. F statistics and Schwarz criteria for sequential reduction of the general supply model to a parsimonious model.

Model	Null hypothesis			Maintained hypothesis					
	K	SC	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6	Model 7
1	37	5.99							
↓									
2	31	5.83	0.50 (6,129) [0.81]						
↓									
3	26	5.73	0.91 (11,129) [0.53]	1.44 (5,135) [0.21]					
↓									
4	21	5.61	0.96 (16,129) [0.51]	1.26 (10,135) [0.26]	1.06 (5,140) [0.39]				
↓									
5	16	5.48	0.91 (21,129) [0.57]	1.10 (15,135) [0.36]	0.92 (10,140) [0.51]	0.78 (5,145) [0.56]			
↓									
6	11	5.36	0.89 (26,129) [0.62]	1.03 (20,135) [0.43]	0.88 (15,140) [0.58]	0.80 (10,145) [0.63]	0.82 (5,150) [0.54]		
↓									
7	8	5.31	1.03 (29,129) [0.44]	1.19 (23,135) [0.26]	1.11 (18,140) [0.35]	1.13 (13,145) [0.34]	1.35 (8,150) [0.22]	2.25 (3,155) [0.08]	
↓									
8	6	5.28	1.14 (31,129) [0.30]	1.33 (25,135) [0.16]	1.28 (20,140) [0.20]	1.35 (15,145) [0.18]	1.64 (10,150) [0.10]	2.48 (5,155) [0.03]	2.77 (2,158) [0.07]

Notes:

1. The same procedure is used here as for the demand model. Thus the initial reduction sequence is done using normal OLS, and only in the final stages is 2SLS used. The notation in Table A3.1 is the same as in Table A2.1.
2. Model 1 is the general supply model (14), using  $k=5$  lags. Model 2 is Model 1 excluding lag 5 of each variable. Model 3 is Model 2 excluding lag 4 of each variable except the lag of squared system turnover,  $Q_{t-4}^2$ . Model 4 is Model 3 excluding squared system turnover,  $Q_t^2$ , and all lags thereof. Model 5 is Model 4 excluding lag 3 of each variable. Model 6 is Model 5 excluding lag 2 of each variable. Model 7 is Model 6 excluding  $\Delta P_{t-1}$ ,  $\Delta R_{t-1}$  and  $Q_{t-1}^*$ . Model 8 is Model 7 with the restrictions  $Q_t = -Q_{t-1}$  and  $I_t = -I_{t-1}$  imposed.
3. The reduction to Model 8 from Model 6 is significant at the 5% level. Model 6 is therefore reestimated with 2SLS using  $Q_{t-2}$ ,  $I_{t-2}$ ,  $\Delta P_{t-2}$ ,  $Q_{t-2}^*$ ,  $\Delta D_t$ ,  $\Delta T_t$  and  $\Delta Prod_t$  as instruments. The restrictions imposed by *both* Models 7 and 8 are now tested, using a Wald test. This has a  $\chi^2$  distribution with 5 degrees of freedom; see Harvey (1990). The test statistic is 7.49 and has a p-value of 0.19. Since the restrictions are not significant, Model 8 is considered valid and I estimate it using 2SLS with  $\Delta P_{t-1}$ ,  $\Delta I_{t-1}$ ,  $\Delta Q_{t-1}$ ,  $Q_{t-1}^*$ ,  $\Delta D_t$ ,  $\Delta T_t$  and  $\Delta Prod_t$  as instruments.<sup>37</sup> The results from this regression, using the full sample, are found in Table 5.

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<sup>37</sup> Sargan's validity test is used to test the instruments. It has a  $\chi^2$  distribution with  $(p-h)$  degrees of freedom, where  $p$  is the number of instruments and  $h$  is the number of regressors on the right-hand side of the equation. Thus there are 5 degrees of freedom in Sargan's test for both Models 6 and 8. The test statistics for Models 6 and 8 are 1.64 and 6.60 with p-values of 0.90 and 0.25, respectively.