Do Bottlenecks generate market power? An Empirical Study of the Norwegian Electricity Market

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This version
December, 2004

Discussion Paper 26/03

SNF project No. 4355
"Konkurransestrategier i det norske kraftmarkedet"

Abstract

The present study analyses the potential non-competitive effects of capacity restrictions – socalled bottlenecks - in the Norwegian electricity market. We specify a structural model, and econometrically identifies market power both for the periods with no capacity restrictions on the grid, and the bottleneck periods. We analyse the largest region, Southern Norway that amounts to three fourths of the Norwegian market. The demand side is found to be inelastic. On average we find the market to be competitive. However, the bottleneck period estimates suggest a significant but small short run markup when the grid is capacity restricted. Hence, within the day or hours when bottlenecks appear it seems as the producers exploit some limited market power.

Keywords: Bottlenecks, capacity restrictions, market power, empirical industry studies

† I am most grateful to Håkon Egeland, Kjell Berger, Jostein Skaar and Lars Sørgard for valuable comments and suggestions. I would also like to thank Statkraft for helping me to access the North Pool database. The author is responsible for any remaining errors or shortcomings.

1. Introduction

There has for a long time been a focus on possible seller market power issues in electricity markets.[1] Recently, there has been an extensive discussion on the potential problems stemming from local capacity restrictions – or socalled bottlenecks – in the electricity grids.[2] The argument has been that local producers can raise their price and profit in these bottleneck periods, and thereby strategically use these periods to gain market power (Joskow and Tirole, 2000; Johnsen, Verma and Wolfram, 2000; Borenstein, Bushnell and Stoft, 1998).[3]

The present study addresses this question empirically, by analysing the Norwegian electricity market. To do so we use high frequent hourly data for the period January 2001 to October 2002. The bottleneck was brought up in one of the last merger cases in this industry, where the largest Norwegian producer Statkraft was allowed to acquire one of its smaller competitors, Agder energi. In this case the question about bottlenecks and potential market power was the main issue. However, the debate at the time was predominantly theoretical.[4]

To our knowledge this is the first study of this market that combines a structural market power model with high frequent hourly data both on demand and costs. Johnsen, Verma and Wolfram (2000) also use hourly data, but have only access to prices and are therefore forced

[1] In the United States and the United Kingdom we have several studies, see for instance Joskow and Schmalensee (1983), Wolfram (1999), Bushnell and Wollak (1999) and Borenstein, Bushnell and Wollak (2000). In the Nordic countries Hjalmarson (2000) has done a general market power study of the Nord Pool market.

[2] See for instance Førsund (1994) and Amundsen and Bergman (2002) for a discussion of market power issues and hydro power production.

[3] The question about the potential non-competitive effects of bottlenecks, is discussed in detail by Joskow and Tirole (2000). They look at various examples where the generators are able to obtain transmission rights and thereby control the transmission capacity. Their setup does not fit the Norwegian market where the system operator controls the utilization of the transmission connections and collect the merchandising surplus. Borenstein, Bushnell and Stoft's (1998) model, suggesting there may be an incentive to withhold capacity to induce a transmission constraint, may hold for the Norwegian system. Johnsen, Verma and Wolfram (2000) analyse the Norwegian market more directly in an empirical model, providing also a comphrehensive survey of the Norwegian electricity market.

[4] See Skaar and Sørgard (2003) and references therein for a summary of the discussion.

to use a lot of structure to be able to identify market power empirically. Here we use the Bresnahan-Lau (1982) model to estimate market power both for the periods with no capacity restrictions on the grid, and the bottleneck periods. The Bresnahan-Lau model is formulated in a dynamic fashion, allowing us to distinguish between short- and long run behaviour.

As we describe in more detail below, Norway is usually divided into two or more regions when bottlenecks appear. We analyse the largest region, Southern Norway that amounts to three fourths of the Norwegian market. The demand side is found to be inelastic. On average we find the market to be competitive. However, the bottleneck period estimates suggests a significant but small short run markup. Hence, within the day or hours when bottlenecks appear it seems as the producers exploit some limited market power. However, the Lerner index implied by the markup estimate only suggests a price 1% above marginal costs. No market power is found in the long run. Since the estimates suggest a very limited markup, the policy implications are not obvious. Market power due to bottleneck, at least as defined by historical data, seems to be of limited importance. Our results, are probably more a "word of warning", that we should be careful to allow more concentration in this market, unless we get rid of the potential bottlenecks in the grid.

The paper is organised as follows. In the next sections we give some background on the industry and the market before we discuss the Bresnahan-Lau model. In section 4 we show the empirical specification before we report the results in section 5. In the last section some concluding remarks are offered.

2. The market

The Norwegian market was one of the first electricity markets to be deregulated. Already in 1991 The Energy Act redefined the regulatory environment. Monopoly franchises that endowed local utilities with exclusive delivery rights were removed, but due to their natural monopolies characteristics, transmission and distribution remained regulated by the Norwegian Water and Energy Administration. Some municipals are still vertically integrated into transmission, distribution and generation, but there is strict accounting separation of transmission and distribution on the one side and generation and marketing on the other. The largest state owned firm was split into a generation firm; Statkraft and a transmission firm; Statnett. Statnett is the system operator (SO) and owns 85% of the Norwegian transmission grid. The Norwegian electricity grid is through overhead lines and sea cables connected to Sweden, Finland and Western Denmark.

When the SO anticipates that major transmission lines can be constrained for a longer period, the market is divided into correspondent bidding areas. Market participants are required to leave their buy and sell bids into the area where they have consumption or production capacity. If the transmission capacity between areas is less than desired transmission based on the bids, there will be a price difference between the areas. This price difference represents a congestion charge.[5] Up to five different areas have been identified within Norway the last five years.[6] However it is rare for the five areas to be separated into five different areas during the same hour. In their 1998 sample, only 1.9% of the observations indicated this division (Johnsen, Verma and Wolfram (1999). At present Norway is generally divided into two price

[5] Comparing Norway to other deregulated electricity markets, the England and Wales pool does not explicitly account for transmission constraints with appropriate price signals. Argentina and New Zealand have adopted some form of zonal pricing, as the Pennsylvania-New-Jersey-Maryland pool and other markets in the United States (Johnsen, Verma and Wolfram, 1999).

[6] The regions are Bergen, Kristiansand, Oslo, Tromsø and Trondheim.

areas, Southern Norway (NO1) and Mid- and North of Norway (NO2). In Johnsen, Verma and Wolfram (1999) sample, this division could be observed for 32.2% of the sample. Partly due to limitations on regional data, and partly because of this more common division into two regions, we will concentrate on the Southern region (NO1) in this paper. This region is also by far the largest region, representing three fourths of the total market. According to Statkraft, in the period 1996 to 2001 NO1 has been a high-price bottleneck area for 15% of the time. In our sample January 2001 to October 2002 the corresponding number is 12.7%.

Nord Pool, ASA, runs the largest organized electricity market in Norway. Since 1993 Statnett Marked, a subsidiary of the SO took ownership of the pool, and the pool was opened to new entrants, such as smaller generators, retailers, traders and large customers. The Nord pool organises two markets, Elspot which is an hourly spot market, and Eltermin which is a forward and futures market. In January 1996 Sweden joined Nord Pool and Finland was fully integrated in 1999. In 2002 there were 208 participants in the spot market, in 2000 the trade was in the order of 96.6 TWh.[7] In a normal year hydroelectric plants generate roughly 113 TWh. Nord Pool works as a wholesale market, since the local electricity providers either have their own production or they buy their deliveries in the market. Many local suppliers will both have local production and Nord Pool trade.

The consumer market has also been deregulated. For several years consumers have been free to choose which producer to buy from, and can switch supplier at any time. End-users are billed separately for energy and distribution charges. As an example, at present 25 – 30 different producer or sellers offer contracts in Oslo, most of these are also covering the rest of

[7] Norwegian Competition Authorities, March 2002.

Norway.[8] Hence, disregarding potential switching cost, and the regulated distribution and transmission, also consumer markets seem quite competitive.

If we look at the Nordic market with no bottlenecks, the C4 index is not very high, with approximately 57%. The four firms are Vattenfall (19%), Fortum/Birka Energi (15%), Statkraft (14%) and Sydkraft (7%). However, within the price regions like NO1, the picture changes quite dramatically. In Southern Norway the C4 is 74%, whereof Statkraft alone represents close to 50%. The latter three divide the remaining 30% quite equally (E-CO Vannkraft, 10%, Norsk Hydro, 10% and Lyse Energi, 7%).[9] This relatively high concentration has been an argument for market power in the bottleneck periods. Another feature in this market is that the demand is quite inelastic, leaving even more scope for potential market power.

The data we use are all available via Nord pool, but we have been given access via Statkraft. We have prices, quantities, reservoirs level and local temperatures for both NO1 and NO2 over a period of several years on an hourly basis. We have, however, only a full dataset for NO1 with all these variables for 22 months; 01.01.2001 to 31.10.2002. The data is described and summary statistics provided in the Table A1 in Appendix A. This leaves us with a dataset of 16 067 observations. In this period we observed 2053 hours with high-price bottlenecks. In these periods the price had an average of NOK 184 as compared to the sample average of NOK 170. (the no bottleneck periods had an average of NOK 168). Hence, prices have been on average 8.4% higher in the high price bottleneck periods. Also the variation in prices seems to be lower. For the full sample the average adjusted standard error in price is 34%,

[8] The Norwegian competition authorities provides dayly information on prices and which suppliers one can choose among on their website: http://www.konkurransetilsynet.no/kraftpriser/kraftpriser.php

[9] These numbers are calculated by the Norwegian Competition Authorities in the merger case with Agder Energi, Agder Energi which is no part of Statkraft had before the merger 9% of the production capacity in NO1 (Norwegian Competition Authorities, March 2002).

whereas it is only 18% in the bottleneck periods. The bottleneck hours typically appear in cold periods. The average temperature is 4.9 as compared to the sample average of 8.9.

Higher prices could be an indication of market power, but this descriptive fact could also be due to higher costs. Hence, in the next sections we will formulate an explicitit model for this market and test for potential market power.

3. How to model market power empirically

There are mainly two strands of literature when it comes to model market power empirically, both within the "New Industrial Organization" framework. For homogenous products the most used model has been the Bresnahan framework (1982, 1989). Here rotation of the demand curve has been used to identify market power.[10] More recently a modelling strategy for differentiated products has been developed. This literature started with the seminal work by Berry Levinsohn og Pakes (1995). Here one exploits differences in product characteristics and economic structure to identify market power.[11] Electricity is a very homogenous product and is therefore very suitable for the Bresnahan framework. To account for the dynamics of the high frequent data used here we apply a dynamic version of the model.

3.1 The Bresnahan Lau model

The demand side may be described by (Bresnahan,1982 and Lau, 1982);[12]

(1) $$Q = D(P, Z; a) + e ,$$

[10] Several studies have applied this methodology in various disguises on several industries. For some of these see on banking; Gruben and McComb (2003), Shaffer (2002, 1993), Suominen (1994), Petroleum; Considine (2001), Cement; Rosenbaum and Sukharomana (2001), Cigarettes; Delipalla and O'Donnel (2001), Beef processing; Mauth and Wohlgenant (1999), Salmon; Steen and Salvanes (1999), Advertising; Jung and Seldon (1995), lumber; Bernstein (1994), Coconut oil; Buschena and Perloff (1991).

[11] See for instance Verboven (1996), Fershtman og Gandal (1998), Petrin, 2002 for studies of the car market and Nevo (2000a; b) for the methodology and the market for breakfast cereals.

[12] This part is largely based on Steen and Salvanes (1999).

where Q is quantity, P is price and Z is a vector of exogenous variables affecting demand. Normally this includes a substitute price and income as the demand is taken to be consumer demand. However, as we are using hourly data, we cannot find income or substitute prices that vary on an hourly basis. However, we will use temperature as a demand shifter (see below). a is the vector of parameters to be estimated and e is the error term.

The supply side is more complex. In a competitive market, price equals marginal costs, and we can write;

(2) $$P = c(Q, W; b) + h,$$

where W are exogenous variables on the supply side, e.g. factor prices, b the supply function parameters, and h is the supply error. Marginal cost is given by $c(\cdot)$. However, when firms are not price takers, perceived marginal revenue, and not price, will be equal to marginal cost. Instead of a supply curve we now may write a supply relation;

(2') $$P = c(Q, W; b) - l \cdot h(Q, Z; a) + h,$$

where $P + h(\cdot)$ is marginal revenue, and $P + l \cdot h(\cdot)$ is marginal revenue as perceived by the firm. Hence, l is a new parameter that may be interpreted as a markup parameter measuring the degree of market power. Under perfect competition, $l = 0$ and price equals marginal cost. When $l = 1$ we face a perfect cartel, and when $0 < l < 1$ various oligopoly regimes apply. Alternatively one can say that l is the percentage of monopoly marginal revenue perceived.

The general empirical problem in all market structure studies is how to identify l. Bresnahan solved this by introducing variables that combine elements both of rotation and of vertical shifts in the demand curve. This is done by formulating an interaction term between P and Z, i.e., changes in a substitute price affects both the position and the slope of the demand curve.

To provide the necessary intuition for the identification principle used, we formulate the simplest version of the static linear BL model. Assuming both demand and marginal cost to be linear, the demand function (1) can be written as; $Q = a_0 + a_P P + a_Z Z + a_{PZ} PZ + e$, and the marginal cost function is; $MC = b_Q Q + b_W W$. The supply relation is now;

$$(3) \qquad P = b_Q Q + b_W W - l\left[\frac{Q}{a_P + a_{PZ} Z}\right] + h \, ,$$

since $MR = P + \left[Q/(a_P + a_{PZ} Z)\right]$. By treating a_P and a_{PZ} as known (by first estimating the demand equation), l is now identified. To see this, write $Q^* = -Q/(a_P + a_{PZ} Z)$. There are two included endogenous variables, Q and Q^* and there are two excluded exogenous variables Z and PZ in (3). Hence, l is identified as the coefficient of Q^* based on the estimation of (3). The inclusion of the rotation variable PZ in the demand function is crucial for this result. The economic implication of including this rotation variable in the demand equation is that the demand function is not separable in Z. Lau shows that identification is possible as long as this is true, regardless of the functional form chosen.

3.2 An Autoregressive Distributed Lag specification of the Bresnahan-Lau model

Markets are dynamic. Firms recognise their own ability to influence market structure, and, thereby, the competition. With influence on the market structure, price and/or quantity become strategic decision variables. Steen and Salvanes (1999) propose a dynamic reformulation of the BL model in an error correcting model (ECM) framework, as there will often be adjustment costs associated with this process. A more present study of the Nordic electricity market by Hjalmarson (2000) use the same dynamic model but in an ADL form.[13] Here we also apply an ADL formulation. The ADL framework incorporates dynamic factors such as habit formation from the demand side and adjustment costs for the producer.[14] An additional argument in favour of using a dynamic model is the presence of high frequency hourly data. The data are strongly serial correlated, and therefore a lag structure is necessary to be able to account for this. The ADL model also provides a dynamic formulation of the oligopoly problem, allowing for both short and long run estimates of market power.[15] This is particular important in this market since the potential market power due to capacity restrictions by nature will be short run market power.

The demand function on ADL form can be written as

$$(4) \qquad Q_t = a_0 + \sum_{i=1}^{k} g_i Q_{t-i} + \sum_{i=0}^{k} a_{P,i} P_{t-i} + \sum_{i=0}^{k} a_{Z,i} Z_{t-i} + \sum_{i=0}^{k} a_{PZ,i} PZ_{t-i}$$

where the long run parameters are given as:

$$(5) \qquad q_j = \sum_{i=0}^{k} a_{j,i} \Big/ 1 - \sum_{i=1}^{k} g_i \quad , \qquad \text{and} \qquad j = P, Y, Z, PZ \quad ,$$

e.g., the parameter q_P measures the stationary long-run impact of P_t on Q_t. $1-\sum_{i=1}^{k} l_i$ is usually denoted as the adjustment speed and measures the impact on Q_t of being away from the long-run target; that is, $1-\sum_{i=1}^{k} l_i$ measures how fast firms can correct the errors of past decisions.

[13] Whether one chooses an ADL form or ECM form depends on the structure of the problem. The two models are however, similar in terms of statistical properties and predictions. This is shown in Steen and Salvanes (1999).

[14] The presence of habit formation in demand, and adjustment costs in supply make static models inadequate (Lucas, 1967; Pollak and Wales, 1992).

[15] Since we do not include an explicitly modelled feedback mechanisms, we assume that the cartel maximises profits in each period, i.e., solves a succession of static problems.

To identify the supply relation and l , some of the demand parameters, e.g. price and interaction parameters, are needed. The natural candidates are the long-run parameters: q_P and q_{PZ}. Hence, the dynamic formulation of the supply relation in (3) is;

$$P_t = b_0 + \sum_{i=1}^{k} f_i P_{t-i} + \sum_{i=0}^{k} b_{Q,i} Q_{t-i} + \sum_{i=0}^{k} b_{Wi} W_{t-i} + \sum_{i=0}^{k} l_i Q^*_{t-i} \,, \tag{6}$$

where

$$Q^*_t = Q_t \Big/ \left(q_P + q_{PZ} Z_t\right) \tag{7}$$

and

$$\Lambda = \sum\nolimits_{i=0}^{k} l \Big/ 1 - \sum\nolimits_{i=1}^{k} f_i \,, x^*_Q = \sum\nolimits_{i=0}^{k} b_{Q,i} \Big/ 1 - \sum\nolimits_{i=1}^{k} f_i \,, x^*_W = \sum\nolimits_{i=0}^{k} b_W \Big/ 1 - \sum\nolimits_{i=1}^{k} f_i \tag{8}$$

The ADL formulation provides both a short-run measure of l : l and a long-run measure, Λ . The supply relation in (6) incorporates adjustment costs and allows short-run deviations from the requirement that marginal cost should equal perceived marginal revenue.

3.3 Empirical Specification

We are here analysing the electricity market. To represent the exogenous Z vector we use temperature. Temperature clearly shifts the demand for energy, and can also serve as a interaction term together with price. Temperature has two other advantages as well, being clearly exogenous and varies substantially also on an hourly basis.[16] Quantity is hourly consumption of electricity measured in megawatt hours. Price is correspondingly NOK per megawatt hour. Since we are interested in the regional effects of bottlenecks we restrict our analysis to one of the two regions in Norway, the southern region. This region represents 72% of the consumption in Norway for the analysed period.

[16] Hjalmarson (2000) used also temperature, but included also day length. Using hourly data day length is not suitable here. He used weekly data so in his study it made more sense to include day length.

Costs are more difficult in this industry, since 99.9% of the electricity production stems from hydropower plants. This implies that the single most influential factor is the water value in the reservoirs – or alternatively, the opportunity cost of water (Førsund, 1994). This can be modelled in several ways, but here we have chosen to use the reservoir level to represent the water value. An alternative would be to include also inflow of water, but this variable is only a less precise estimate of the reservoir level. On the other hand, the reservoir level is not as exogenous as water inflow, since the producers will have some possibility to adjust the reservoir level for strategically reasons. Since a minor share of the production is imported from nuclear, coal and oil power plants elsewhere in the Nordic region we could have included also other cost shifters like coal prices. However, prices on coal, oil and uranium are very stable and on the margin import is low. We therefore limit our cost side to the opportunity cost of water, instrumented by the reservoir level.[17] The summary statistics of the data used can be found in Table A1 in Appendix A.

Before we formulate the equations to be estimated, some additional characteristics of the electricity market must be considered. Electricity consumption varies over the day, week and also according to season. Hence, we include a number of dummy variables in the demand equation. We include dummy variables for the 24 hours of the day (*H0-H23*), dummy variables for each week day (*D1-D7*), and dummy variables for each month (*M1-M12*).[18] Finally we include a linear time trend (*trend*). The demand function in (4) may then be extended to:

$$\begin{aligned} Q_t &= \sum_{i=1}^{k} \gamma_i Q_{t-i} + \sum_{i=0}^{k} \alpha_{P,i} P_{t-i} + \sum_{i=0}^{k} \alpha_{Z,i} Z_{t-i} + \sum_{i=0}^{k} \alpha_{PZ,i} PZ_{t-i} \\ &\quad + \sum_{j=0}^{23} Hj_t + \sum_{j=1}^{7} Dj_t + \sum_{j=1}^{12} Mj_t + \psi\, trend_t + \eta_t \end{aligned} \tag{10}$$

[17] Another factor that differs across hydroelectric plants is the turbine capacity. The larger the capacity the higher is the implicit opportunity cost of water. However, using large regions as here these figures are less important on the aggregated level. Furthermore, these numbers do nearly not change over the analysed period and is therefore partly accounted for through the constant term.

[18] To prevent the “dummy trap” we exclude the constant term, an hourly dummy for the eight hour (08:00-09:00) of a day, and the Day 2 dummy (Tuesday).

and the supply relation from (6) is now:

$$(11) \qquad P_t = b_0 + \sum_{i=1}^{k} f_i P_{t-i} + \sum_{i=0}^{k} b_{Q,i} Q_{t-i} + \sum_{i=0}^{k} b_{Wi} W_{t-i} + \sum_{i=0}^{k} l_i Q^*_{t-i} + j\,trend_t + e_t$$

where W is reservoir level, and $Q^*_t = Q_t / \left(q_P + q_{PZ} Z_{tt}\right)$.

The supply relation in (11) only provides us with an average mark-up for the whole period we analyse. To implement parametric tests for a possible shift in market power due to bottlenecks we need to extend the model. This is done by including a second markup variable that is measuring mark-up in the periods where bottlenecks appeared in the grid. These are defined as the periods when the prices between North and South differ, and the Southern market is a "local" market and the producers might find it profitable to raise prices above competitive levels.

(11')

$$P_t = b_0 + \sum_{i=1}^{k} f_i P_{t-i} + \sum_{i=0}^{k} b_{Q,i} Q_{t-i} + \sum_{i=0}^{k} b_{Wi} W_{t-i} + \sum_{i=0}^{k} l_i Q^*_{t-i} + \sum_{i=0}^{k} l_i^{bottleneck} Q^*_{bottleneck\,t-i} + j\,trend_t + e_t$$

Where $Q^*_{bottlenec,t} = (Q_t / (q_P + q_{PZ} Z_t)) \cdot D_{bottleneck}$. The latter variable is a bottleneck hour dummy that indicates when high price bottlenecks periods appear.[19] The error terms are assumed to have the standard properties.

The estimation is done in two steps.[20] To account for the simultaneity problem, (10) is estimated using an instrumental variable technique, two stage least squares (2SLS), using W,

[19] Highprice bottlenecks is all the price periods where capacity restrictions appear and the price in NO1 is higher than NO2.

[20] When using static models it has become standard practice to estimate the demand equation and the supply relation simultaniously. However, this is more difficult here since the long-run structure impose even more non-linearities on the problem.

the reservoir level as instrument in the demand equation. Then, after having calculated the Q^* variables, (11) and (11') are estimated using the same technique, with temperature, hourly, daily and monthly dummys as instruments.

To be able to decide how many lags that is needed we start with k=26, and then test our models down by excluding non-significant lags. Finally we use the Box-Pierce autocorrelation tests to decide whether we can keep the reduced model. Both the static models and the models including all lags up to 26 clearly failed the autocorrelation tests.

4. Empirical results

The main demand function results are presented in Table 1. The dummy variable results are tabulated in Table B1 in Appendix B. The statistical properties of the model are good. The centered R^2 is 0.99, and all main parameters are significant. The Box-Pierce autocorrelation statistics show no autocorrelation (Q1, Q2 and Q12). In Table 2 the economic predictions are summarised. The price elasticities are both reasonable. The short run elasticity is -0.11 and the long run steady state elasticity is -0.04.[21] Since our prices comes form Nord Pool and this is a wholesale market, it is reasonable to find that short run demand is more responsive than long run demand. In the short run the wholesale buyers are quite price sensitive, but in the longer run derived consumer demand makes the Nord pool wholesale buyers less elastic. We should also note that long run is more than 25 hours here. This implies that within the day the buyers are more price sensitive than between two different days. Hjalmarson (2000), using weekly data but for an older and longer period (2:1996 to 16:1999) also found a long run elasticity of -0.04.

[21] Note that the demand elasticities are a mix of the own-price parameters and the rotation term parameters, e.g., the demand elasticity is given as: $e_{ii}^{LR} = \left(q_P + q_{PZ} \cdot \overline{Z}\right) \cdot \overline{P}/\overline{Q}$. The temperature elasticity can be found in the same fashion.

We find the opposite picture for temperature. Here the market is less elastic in the short run, than in the long run. When the temperature falls, consumption increases more between days than within the same day. This result can partly be explained by a natural lag in consumer demand changes following temperature changes. The adjustment speed is quite low; only 0.042. However, note that since we are using hourly data, this number suggests that accumulated, 65% of the short run deviations have been corrected for after 24 hours.

[Table 1 and 2 approximately here]

Given that we now have a reasonable demand model, we turn to the supply relations. The first supply relation (11), where we estimate the average markup over the sample period is presented in Table 3. Also here the statistical properties are good. The centered R^2 is 0.84 and the parameters are significant. The Box-Pierce autocorrelation statistics are even lower suggesting even less autocorrelation. The economic predictions are summarised in Table 4. The adjustment speed is marginally higher, suggesting that out of equilibrium behaviour is corrected with 70% after 24 hours. Turning to the reservoir elasticities we obtain an interesting result. There are absolutely no short run effects from reservoir changes. None of the lags from t to (t-6) for the reservoir variable are significant in our models. Hence, it takes some time before changes in the reservoir level influence prices. When this happens, our model suggests an effect of -0.16. Hence, a 0.16% increase in the reservoir level reduces the opportunity cost of water and thereby price with 1%.

[Table 3 and 4 approximately here]

The mark-up estimates suggest no market power in the long run, with a clearly insignificant parameter. In the short run – within the day – we find weak evidence of a positive mark-up parameter, suggesting what one often refers to as a "super-competitive" market. However, since the parameter is significant only on a 10% level, and is very close to zero (0.0078), the most likely conclusion is a competitive market. Hence, on average we find no market power in the electricity market in Southern Norway. This result is also in accordance with what Hjalmarson (2000) found, and seems reasonable when you consider the number of participants in this market. As we have discussed above, this conclusion might be premature if the market power predominantly appears when we experience bottlenecks in the grid. Thus, we now turn to our second supply relation (11') where we test for the effect of bottlenecks more directly.

The results for the supply relation (11') are presented in Table 5. The statistical properties are good, the centered R^2 is 0.84 and the parameters are significant. No autocorrelation is present. The economic predictions are summarised in Table 6. The adjustment speed is the same as for the previous supply relation. The reservoir elasticities are also more or less equal.

[Table 5 and 6 approximately here]

The mark-up estimates change, however. The markup estimates still suggest no market power in the long run, with clearly insignificant long run parameter for Λ in both models. However, in the short run, we now *find statistical significant market power in the bottleneck periods*. The average effect is still positive and now also non significant on all conventional significance levels. Hence, when we augment our supply relation to include a particular markup effect for the bottleneck periods, we find some market power in this market. It is reasonable that this market power is a short run – within the day – effect. Actually only two lags were found to be significant for the bottleneck markup variable. This suggests that already after three hours the market power effect might disappear. Since bottlenecks are a short run phenomenon, this seems as a reasonable result. It is important to note that even though the bottleneck markup is strongly significant (2.5% level), it is very low, with an estimate of only -0.0005. Even if we calculate the implied Lerner index the figures suggests only a 1% price over marginal costs.[22] This suggests that the possibility of extracting market power rent from this market is quite restricted for the producers.

5. Concluding remarks

Here we have used high frequent hourly data for 22 months from January 2001 to October 2002 to formulate a dynamic structural Bresnahan-Lau model for the electricity market in Norway. We augment the model to allow for separate markup estimates for the bottleneck periods. The demand side is found to be inelastic, with a long run elasticity of -0.04. On average we find the market to be competitive. However, the bottleneck period estimates suggest a significant but small short run markup. Hence, within the day or hours when bottlenecks appear it seems as the producers exploit some limited market power. No market power is found in the long run – that is between different days.

Our results are actually in line with what Johnsen, Verma and Wolfram (2000) got, using more structure and less data. For only one of the five regions they looked at they found some market power, and then only for 120 hours of their sample, suggesting that market power is a problem only in 1.4% of the periods in *one* out of five regions. Hogan (2000) actually made some critique on their results since their methodology required several very strong

[22] The implied Lerner index is defined as $(P-MC)/P = -l/e$, where e is the absolute value of the residual demand elasticity; $e = |e_{PP}|$ (Buschena and Perloff, 1991).

assumptions. He also raised doubt with the policy implications: *"The methodology is clever, and the results are persuasive within the framework of the strong assumptions. But we should ask: Does a 15% increase in price in one of the regions, for the 120 constrained night time hours in 1998, suggest a major policy problem?"* Hogan, (2000). If we look at our sample, it was only in 12.7% of the 16 000 hours that we observed bottlenecks. The economic significance of this problem is therefore small. Our results, as Johnsen, Verma and Wolfram (2000) are probably more a "word of warning" that we should be careful to allow more concentration in this market, unless we get rid of the potential bottlenecks in the grid.

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Tables

Table 1 Demand estimates

	Coefficient	**Stnd.Er.**
Price (*P*)		
t	-5.7753***	(1.9665)
t-1	5.6947***	(1.8175)
t-2	-0.3810***	(0.1302)
t-24	1.7291***	(0.5648)
t-25	-1.3999***	(0.3766)
Temperature (*Z*)		
t	42.6622**	(19.4516)
t-1	-51.3411***	(17.6287)
t-24	-14.1234***	(5.8716)
t-25	15.2909***	(4.0828)
Price x Temperature (*PZ*)		
t	-0.3446***	(0.1148)
t-1	0.3285***	(0.1026)
t-24	0.0959***	(0.0336)
t-25	-0.0803***	(0.0225)
Consumption (*Q*)		
t-1	1.2467***	(0.0139)
t-2	-0.3630***	(0.0166)
t-3	-0.0813***	(0.0165)
t-4	0.0656***	(0.0107)
t-7	-0.0172***	(0.0059)
t-10	0.0824***	(0.0095)
t-11	-0.0626***	(0.0106)
t-15	-0.0370***	(0.0058)
t-17	0.0544***	(0.0065)
t-24	0.3466***	(0.0102)
t-25	-0.2970***	(0.0169)
t-26	-0.0312**	(0.0154)
t-27	0.0513***	(0.0115)
trend	-0.0010**	(0.0005)
R2	0.994	
N	15 513	
Q1	7.167	
Q2	7.186	
Q12	19.820	

***/significant at a 2.5% level, **/significant at a 5% level, */significant at a 10% level

Table 2 Elasticities from the demand model

Elasticities/ adjustment speed	**Estimate**	**Chi-square statistics** ($H^{0}_{estimate} = 0$)
<u>Elasticities</u>		
Price short run	-0.112***	8.74
Price long run	-0.044	2.24
Temperature short run	-0.034***	9.02
Temperature long run	-0.133***	170.8
<u>Adjustment speed</u>	0.042***	163.48

***/significant at a 2.5% level, **/significant at a 5% level, */significant at a 10% level

Table 3 Supply relation (i)

	Coefficient	**Stnd.Er.**
Reservoir (*W*)		
t-7	-4.4699***	(0.8160)
t-8	3.7911***	(0.8548)
t-18	2.4351***	(0.8723)
t-19	-2.9659***	(1.1774)
t-20	3.1043***	(1.1724)
t-21	-1.9027***	(0.8303)
Markup variable (Q_t^*)		
t	0.0079*	(0.0045)
t-10	-0.0169***	(0.0030)
t-12	0.0142***	(0.0033)
t-13	-0.0101***	(0.0028)
Price (*P*)		
t-1	0.9999***	(0.0078)
t-2	-0.2443***	(0.0088)
t-4	-0.0269***	(0.0088)
t-5	0.0265***	(0.0111)
t-6	0.0310***	(0.0112)
t-7	-0.0654***	(0.0112)
t-8	0.1269***	(0.0112)
t-9	0.0256***	(0.0112)
t-10	0.0529***	(0.0112)
t-11	-0.1469***	(0.0090)
t-13	0.0753***	(0.0067)
t-15	0.0626***	(0.0090)
t-16	-0.0815***	(0.0112)
t-17	0.0295***	(0.0112)
t-18	-0.0345***	(0.0089)
t-20	0.0275***	(0.0088)
t-21	0.0603***	(0.0111)
t-22	-0.0673***	(0.0112)
t-23	0.0546***	(0.0113)
t-24	0.1735***	(0.0112)
t-25	-0.1804***	(0.0111)
t-26	0.0504***	(0.0079)
Consumption (*Q*)		
t	0.0146***	(0.0018)
t-1	-0.0043***	(0.0015)
t-2	-0.0035***	(0.0009)
t-9	-0.0047***	(0.0007)
t-16	-0.0009***	(0.0003)
t-24	-0.0027***	(0.0003)
trend	-0.0001***	(0.0000)
Constant	14.2203***	(3.0248)
R2	0.845	
N	15 568	
Q1	0.110	
Q2	0.112	
Q12	5.107	

***/significant at a 2.5% level, **/significant at a 5% level,
*/significant at a 10% level

Table 4 Elasticities, mark-up estimates and adjustment speed from Supply relation (11)

Elasticities/Mark-up/ Adjustment speed	**Estimate**	**Chi-square statistics ($H^{0}_{estimate} = 0$)**
Mark-up estimate		
Mark-up short run (l_0)	0.0078*	1.73§
Mark-up long run (Λ)	-0.096	1.31
Reservoir elasticity		
Reservoir short run	0†	-
Reservoir long run	-0.159	0.57
Adjustment speed	0.051***	101.03

§/t-value

†/there are no direct reservoir effect on price, the first significant lag of the reservoir variable is (t-7), the last significant lag is (t-21) suggesting only a long run effect from reservoir changes.

***/significant at a 2.5% level, **/significant at a 5% level, */significant at a 10% level

Table 5 Supply relation (11')

	Coefficient	**Stnd.Er.**
Réservoir (*W*)		
t-7	-4.8360***	(0.8203)
t-8	4.2421***	(0.8590)
t-18	2.5007***	(0.8768)
t-19	-3.0212***	(1.1836)
t-20	3.0525***	(1.1783)
t-21	-1.9454***	(0.8345)
Markup variable ($Q^{*}_{bottlenec,t}$)		
t	-0.0005***	(0.0002)
t-2	0.0004*	(0.0002)
Markup variable (Q^{*}_{t})		
t	0.0022	(0.0050)
t-9	0.0235***	(0.0023)
t-10	-0.0865***	(0.0105)
t-12	0.0594***	(0.0098)
Price (*P*)		
t-1	1.0046***	(0.0078)
t-2	-0.2525***	(0.0088)
t-4	-0.0355***	(0.0089)
t-5	0.0246**	(0.0111)
t-6	0.0303***	(0.0113)
t-7	-0.0664***	(0.0112)
t-8	0.1272***	(0.0113)
t-9	0.0288***	(0.0113)
t-10	0.0507***	(0.0113)
t-11	-0.1437***	(0.0090)
t-13	0.0793***	(0.0067)
t-15	0.0606***	(0.0090)
t-16	-0.0848***	(0.0112)
t-17	0.0282***	(0.0112)
t-18	-0.0304***	(0.0089)
t-20	0.0310***	(0.0089)
t-21	0.0593***	(0.0111)
t-22	-0.0613***	(0.0113)
t-23	0.0616***	(0.0113)
t-24	0.1742***	(0.0112)
t-25	-0.1794***	(0.0112)
t-26	0.0405***	(0.0079)
Consumption (*Q*)		
t	0.0060***	(0.0017)
t-10	-0.0197***	(0.0033)
t-12	0.0164***	(0.0032)
t-24	-0.0029***	(0.0003)
trend	-0.0001***	(0.0000)
Constant	12.9015***	(3.1687)
R2	0.843	
N	15 572	
Q1	0.048	
Q2	0.645	
Q12	12.906	

***/significant at a 2.5% level, **/significant at a 5% level, */significant at a 10% level

Table 6 Elasticities, mark-up estimates and adjustment speed from Supply relation (11')

Elasticities/Mark-up/ Adjustment speed	**Estimate**	**Chi-square statistics** **($H^0_{estimate} = 0$)**
<u>Mark-up estimate</u>		
"Average effect"		
Mark-up short run (l_0)	0.0022	0.43[§]
Mark-up long run (Λ)	-0.027	0.09
"Bottleneck-periods"		
Mark-up short run ($l_0^{bottleneck}$)	-0.0005***	-2.46[§]
Mark-up long run ($\Lambda^{bottleneck}$)	-0.029	0.11
<u>Reservoir elasticity</u>		
Reservoir short run	0[†]	-
Reservoir long run	-0.137	0.46
<u>Adjustment speed</u>	0.053***	108.6

[§]/t-value
[†]/there are no direct reservoir effect on price, the first significant lag of the reservoir variable is (t-7), the last significant lag is (t-21) suggesting only a long run effect from reservoir changes.
***/significant at a 2.5% level, **/significant at a 5% level, */significant at a 10% level

Appendix A – The dataset

All data was provided in their final form from Statkraft. We use data for the period 01.01.2001 to 31.10.2003. The summary statistics are presented in Table A1.

Table A1 Summary statistics main variables

	Price	**Consumption**	**Reservoir**	**Temperature**	**Mark-up variable**
All Periods					
N	16056	16056	16056	16056	16056
Mean	170.1	9746.3	64.6	7.4	-3063.8
Std. dev.	57.3	2429.8	18.2	8.9	853.1
Min	21.0	4859	29.6	-20.2	-5833.1
Max	1951.8	16986	90.1	28.4	-1481.7
No-Bottleneck periods					
N	14001	14001	14001	14001	14001
Mean	168.0	9653.0	64.4	7.8	-3030.3
Std. dev.	59.8	2451.0	18.3	9.1	861.5
Min	21.0	4859	29.6	-20.2	-5833.1
Max	1951.8	16986	90.1	28.4	-1481.7
Bottleneck periods					
n	2053	2053	2053	2053	2053
Mean	184.4	10382.4	65.7	4.9	-3292.0
Std. dev.	33.2	2175.9	17.5	7.5	755.1
Min	48.3	6224	29.6	-15.2	-5329.7
Max	738.8	15903	88.8	25.7	-1863.3

Appendix B – Demand results dummy variables

Table B1 Demand results dummy variables, hour, day and month

	Coefficient	Stnd.Er.
Hour 0	-220.6119***	(24.7439)
Hour 1	-180.4621***	(35.9611)
Hour 2	-169.6783***	(35.0400)
Hour 3	-182.6368***	(32.2586)
Hour 4	-141.6790***	(28.6925)
Hour 5	-24.3926	(18.0165)
Hour 6	210.2078***	(16.3007)
Hour 7	278.8580***	(13.8614)
Hour 9	24.6996*	(15.2433)
Hour 10	102.7473***	(14.9733)
Hour 11	-24.4453	(19.5911)
Hour 12	-22.1045	(26.5568)
Hour 13	-16.2208	(27.6313)
Hour 14	-19.9499	(31.4905)
Hour 15	-37.6103	(31.4970)
Hour 16	4.0328	(27.6294)
Hour 17	6.8868	(22.9284)
Hour 18	-21.8423	(23.1881)
Hour 19	-25.6787	(23.9871)
Hour 20	-37.8312*	(22.1845)
Hour 21	-41.4002***	(19.0004)
Hour 22	-122.4342***	(20.6789)
Hour 23	-175.4485***	(27.3307)
Day 1	-137.5873***	(11.3030)
Day 3	-83.1782***	(8.6762)
Day 4	-77.3762***	(8.7751)
Day 5	-90.4840***	(9.3204)
Day 6	-96.2262***	(9.5523)
Day 7	-181.8489***	(12.4842)
Month 1	718.4695***	(63.5753)
Month 2	715.9664***	(63.7626)
Month 3	689.0671***	(63.0694)
Month 4	657.2829***	(62.4999)
Month 5	624.3237***	(61.7637)
Month 6	632.1020***	(62.7717)
Month 7	616.5739***	(61.8478)
Month 8	649.7313***	(64.7542)
Month 9	649.6739***	(64.8204)
Month 10	671.2420***	(64.9304)
Month 11	694.9321***	(63.5637)
Month 12	708.0046***	(64.0995)

(Hour 0 reefers to 00:00-01:00, etc., Day 1 reefers to Monday etc., and Month 1 reefers to January etc.)
***/significant at a 2.5% level, **/significant at a 5% level, */significant at a 10% level