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Hydro Power

An Econometric Analysis of Market Power Exertion in the Nordic Electricity Market

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Abstract

The thesis examines the major hydro producers' exertion of market power in the Nordic wholesale electricity market, Nord Pool, in the period from 2014 through 2016. Building on the economic notion that only firms with market power dictate their production according to the price elasticity of demand, I build an IV regression model that isolate the effect of changes in this price responsiveness on spot prices in the day-ahead market. The main results show that a reduction of 0.1 in elasticity is associated with an increase in spot prices of about 2 €/MWh. This advocate that the hydro suppliers had limited, but statistically significant, market power in the sample period.

Acknowledgements

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The author is grateful to Morten Sæthre for suggesting the topic explored in the thesis, as well as for providing guidance and supervision throughout the process. Your instructions have been cardinal in the forming of this paper. Any remaining mistakes are exclusively my own.

Lastly, I would like to extend a heartfelt "Congratulations" to my fellow graduating classmates from the Master's program at NHH. Thank you for making the last two years memorable and I wish you all the best in your future endeavours.

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1. Introduction

The pinnacle contribution of this thesis is a recent empirical examination of the exertion of market power in the Nordic wholesale electricity market through an isolation of the effect on spot prices from variations in demand elasticity. The performance of electricity markets has been widely studied as they have been gradually more deregulated and privatized since the 1990s. These markets are especially interesting for researchers within industrial organization, as characteristics like highly inelastic demand and a significant ownership concentration of generator capacity potentially enables non-competitive use of market power in production. Electricity being a fully homogenous end-good, is also helpful in that it serves to eliminate any potential noise in the estimation from product differentiation or branding effects. Finally, the noble amount of freely available data on both the supply and demand side of the market permits researchers to directly observe the actual aggregated supply and demand curves rather than estimating these through simultaneous equation methods. In this way, empirical research can be conducted with far fewer ancillary assumptions than is the norm for models that aim to empirically quantify the effects of market power in other industries. According to economic theory, the elasticity of this aggregated demand curve will impact how a profit-maximizing producer (or multiple producers in unison) with market power and short-term flexibility in production choose to bid their supply into the market.

The prime channel through which companies with market power induce a deadweight loss on society is strategic output contraction. That is a deliberate shift of supplied quantum from periods where the demand side is relatively inelastic to periods when the price responsiveness in the market is higher. An unregulated monopoly is the most extreme case of this economic phenomenon, where the sole supplier limits her production to the level where the marginal cost of supply is equal to the marginal revenue (Tirole, J., 1988).

Theoretically, I demonstrate the difference between this monopoly solution at one extreme and the free competition solution at the other end of the spectrum. Large hydro producers will hypothetically exist somewhere in between these extremes; enforced to compete with other electricity generators, but maintaining some leverage to influence the prices in the market. The causal entanglement of factors deciding the prices and quantities traded at the Nordic power market is not easily mapped out. In line with previous studies like Lundin and Tangerås (2017), it can however be shown that an exogenous demand shift will affect the clearance price of the market through two additively separable channels. A positive shift will ceteris paribus induce a positive effect on price through moving the equilibrium up the rising supply curve. In the event of suppliers utilizing market power, the equilibrium price will also be affected by changes in the elasticity of the demand curve. The latter effect stems from large producers contracting (expanding) their output in periods with relatively inelastic (elastic) demand, thereby further increasing the equilibrium price (quantum) to maximize profits. This theoretical phenomenon is an exertion of market power, and the foundation of this empirical study of the competitiveness of the Nordic electricity market.

The details of this empirical study are presented in chapter 5, while the results from applying it to data from Nord Pool's day-ahead market from mid 2014 through 2016, follow in chapter 6. I use an instrumental variable approach to regress the spot price on cleared volume and the arc elasticity of demand. The rationale being that by successfully separating these two effects the market power component of the price development may be isolated.

Consistent with firms exercising market power, the analysis shows that the market cleared on slightly, but statistically significant, higher spot prices when the responsiveness of the demand-side was weaker. As this statistical relationship is inconsistent with perfect competition, I reject the null hypothesis that the Nordic day-ahead market for wholesale electricity was perfectly competitive in the observed period.

1.1 Literature Review

The global surge of ample data throughout the last few decades has spurred a vast body of literature examining the exercise of market power in liberalized electricity markets. The most similar papers to the present study in terms of methodological approach and data used are Lundin and Tangerås (2017), Bye, Hansen (2008) and Bask et al. (2008), who all rely on aggregate bid curves for their analyses. Tangerås and Lundin separate out low price bidders as "Cournot competitors" and analyse the use of their market power in the Nordics over the period 2011-2013. In particular, they estimate the effect of changes in the slope of the inverse residual demand curve facing these Cournot competitors on the quantities they bid into the market. Their method rests on an assumption of all changes in demand occurring as horizontal shifts in the demand of fringe competitors, while Cournot competitors are bidding their quantum inelastically into the market at low prices. Bye and Hansen on the other hand, focus on mapping the short- and long-run demand response to spot prices in Norway and Sweden across hours throughout the week, seasons and geographical areas. The paper by Bask et al (2008) examine how the degree of market power changed throughout the process of transforming the electricity markets in the Nordics from a national to a combined cross-border model. Contrary to Tangerås and Lundin, they rely upon the conjectural variations approach developed by Bresnahan (1982) and Lau (1982). Bask.et.al. use weekly aggregated data. All three papers find limited but statistically significant evidence of market power exploitation in the Nordic market, albeit for different time periods.

Similar studies have also been performed on electrical power markets outside of the Nordics. Seminal studies like Green and Newberry (1992), Wolak and Patrick (1997) and Wolfram (1999) all found evidence of market power in the UK market.

While firm-level bid curves are not available in the Nordic market, this information has been used in studies of other electrical power markets and Borenstein, Bushell and Wolak (2002) and Borenstein, Bushell, Knittel and Wolfram (2008) utilize this detailed data on the generator side to find significant evidence of market power in the California market, especially in the summer months. McRae and Wolak (2014) find similar results among large producers in New Zealand, so does Bigerna, Bollino and Paolo Polinori (2016) for the Italian market.

The lack of public firm-level bid data in the Nordic market is circumvented by a distinctive approach taken by McDermott (2019). He utilizes firm-level reservoir data to craft a fully empiric model which he uses to conclude that dominant Norwegian hydro producers keep higher reservoir volumes in the summer months. This is consistent with market power behaviour.

Finally, strategically withholding production is not the only way to apply market power in the electricity market. Ito, Koichiro and Reguant (2015) demonstrate how wind farm producers practice profitable arbitrage in sequential markets and thus reduce consumer prices, but also induce a deadweight loss on the Iberian market. Alongside the conventional market of suppliers and retailers or large consumers of electricity, a purely financial trading market for electricity also exists. A paper by Mercadal (2016) examines how this element affect market power in the American Midwest, and concludes that the financial markets serve to alleviate supply-side market power, which potentially benefit the consumer but can also reduce the efficiency in the market.

2. The Norwegian Electricity Market

Electricity is an indispensable commodity in any modern society. The challenges associated with storing electrical power impose a unique requirement of constant physical equilibrium in the market. Any deviation between total production and consumption in the system will distort the frequency of the alternating current from the balancing point, which across Europe is 50Hz. If the central operator’s regulation measures fail to re-balance this equilibrium, the market asymmetry can cause a system-wide black-out. This system is however primarily responsible for minor real-time adjustments. The main market operations are handled on the power exchange, where aggregated supply and demand bids are matched to clear the market at a common price.

Nord Pool is the largest market for electrical energy in Europe with a record 524 TWh of traded power in 2018. It mainly operates in the Nordic countries and the Baltic region, but also manages important markets in Germany, France, The Netherlands, Belgium, Austria and the UK. In total 380 companies from 20 countries trade on Nord Pool’s different markets. These countries are divided further into market areas. Norway currently consists of 5 market areas, Eastern and Western Denmark are separate, Sweden have been 4 areas since 2011, while Finland, Latvia, Lithuania and Estonia constitute one area each (Johansen, 2019).

Like most other liberalized electricity wholesale markets, Nord Pool is organized like a Walrasian auction, in that the market participants place a series of price-dependent bids that a central auctioneer matches to clear the market. Nord Pool’s main channel for trading physical electricity is the hourly day-ahead market, *Elspot*. At this market, the participants at noon (CET) bid in the volumes they are willing to buy/sell at different prices for each hour the following day. The theoretical price at which the market clears each hour is called the *system price*. This price will reflect both the cost of producing the most expensive KWh of power traded, and the highest price that the buyers are willing to pay for the marginal KWh to clear the market. The price formation process is therefore economically effective for society. The system price applies within all of Nord Pool, as long as no transmission constraints between the different market areas are binding. Whenever these infrastructural constraints limit the transfer of power, the market is divided into different bidding areas with distinct equilibrium prices. In times where the demand outweigh supply in an area by more than can be imported with the current infrastructure, prices will increase to counteract the rising demand.

In addition to the regular supply and demand bids, it is possible to place an order for a given amount of electrical power at a given price for a specified set of consecutive hours within the same day. These orders are called *block bids* and usually come with the condition that they must be either fully accepted or fully rejected based on how the set price compares to the average price in the relevant bidding area across the hours it covers. There are block orders on both the supply and demand side. Blocks bid in by producers are accepted if the price is lower than the average market price, while blocks bid in by actors on the demand side are accepted if the proposed price is higher than the average market price.

The non-storability characteristics of electricity can introduce the need to adjust positions after the Elspot deadline. This might happen if a Swedish nuclear plant abruptly is unable to produce, or strong winds increase the supply from a Danish Wind farm. The intraday market, *Elbas*, serve to largely balance these discrepancies between contracted volume from the day-ahead market and actual supply/demand for the market participants. Despite a growing share of unpredictable wind power making Elbas increasingly important, it only accounts for about 1% of the total volume traded in the Nord Pool area, and it will not be further elaborated on in this paper. Nord Pool also consist of a market for financial contracts that are used for hedging prices and managing risk. There are no physical deliveries of power associated with the contracts in the financial market, so actors that don't produce or demand electricity are also able to invest in this market in pursuit of profits (Johansen, 2019).

Integrating several different countries into a common grid secures that the electricity comes from a wider range of sources and that the consumers are more geographically dispersed. Both features make the market more resilient towards factors that interfere with the market balance, like severe droughts or extraordinary cold temperatures. The fluent transfer of electricity across country boarders thus facilitate a more secure power supply, and stimulate trading, which makes the market 'liquid'. Nord Pool is an expansion of the world's first internationally integrated power market that was initiated in the Nordics in 1996. The mentioned benefits of this deregulated approach have motivated a range of similar solutions in electricity exchanges all over the world. The European Energy Exchange (EEX), Amsterdam Power Exchange (APX), and Californian Power Exchange (CalPX) are examples of other prominent power exchanges around the Globe (Førsund, 2015).

In the following sub-chapters I will go more specifically in-depth on the key features of the supply and demand side of the Nordic market for wholesale electricity.

2.1 Supply

The supply side of Nord Pool is made up of a broad range of producers that each bid their chosen price-dependent production levels into the exchange. The distribution of different sources of energy in the market at any time is known as the *supply mix* of electricity. Every means of production has its own characteristics and seasonal and geographical patterns. The distribution thus affect factors like how responsive the market is to changes in demand or external events like periods with heavy rain or frigid temperatures. *Figure 1* demonstrates that the Nord Pool area is dominated by hydro producers, while nuclear power, wind and a few other sources are also prominent energy sources in the market. The chart reflects the data for 2016, the supply mix was however fairly stable across the relevant period. 95% of the electricity production in the market is generated in the Nordics, where Norwegian hydro is dominant along with Swedish hydro and nuclear plants. In the Baltic region, more than 75% of the electricity production comes from thermal sources (("International Energy Agency Report", 2016). Note that these statistics not exclusively captures the electricity traded on the day ahead market. Detailed region-specific data on production, consumption, imports and exports, are provided in appendix 1.

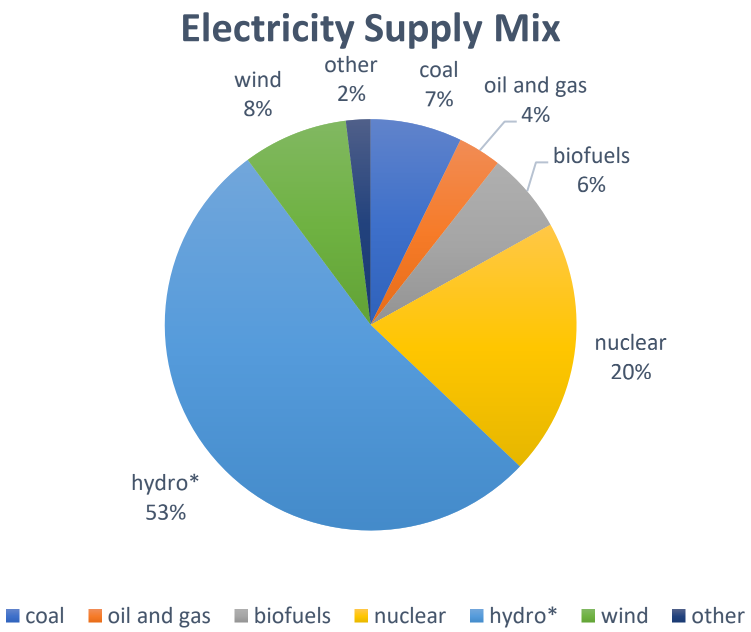

*Figure 1: Nord Pool supply mix (2016). *also include run-of-the-river plants*

2.1.1 Thermal energy production

The term *thermal energy* refers to every method of producing electrical power from heat. This heat can be generated by burning coal, biofuels, oil, gas or through nuclear plants. According to *figure 1* thermal energy sources constitute about 37% of the total production in Nord pool. These energy sources are profitable as long as spot prices for electricity are higher than the relevant production costs. Important factors for determining these costs are prices of the relevant input resources as well as additional costs like CO_2 emission prices.

Thermal production sources are largely inflexible, meaning that short-term adjustments of production levels are usually unprofitable. There are significant costs associated with start-up and alterations of production levels for plants that run on energy sources like coal or nuclear, this restricts the producers being able to follow rapidly changing market events. These plants might therefore lose money on their production for some hours, as their production decisions are made with regards to optimize across longer time horizons. The lack of flexibility in production restricts these producers to supply a steady base load of production for a given period. Because of this characteristic, this power is often referred to as a *baseload power.* In periods where hydro producers are experiencing very low reservoir levels, which impedes their production flexibility, thermal-related supply shocks like increases in coal prices can heavily affect the equilibrium prices. This is especially true in periods of inelastic demand (Førsund, 2005).

2.1.2 Intermittent energy production

Producers that rely on intermittent production technologies like wind and solar power are considering a sharply different production decision. Relevant production costs are significantly lower than for thermal plants, since they rely only on freely available sources of energy like sunlight, wind and rivers. Furthermore, it is highly problematic to store sunlight or wind, these producers are therefore typically willing to bid their electricity into the market at any positive price. Their supply is essentially independent of spot prices for this reason. It does however affect the production decision of hydro producers through changing the market prices and thereby the water value. Wind is also complicated in that increased wind levels induce a positive demand shift through increasing the need for spatial heating in poorly isolated buildings.

The production from intermittent energy sources is vulnerable to the absence of the source of energy they rely upon. As an example, there is nothing a wind producer can do to make the wind blow, they can only utilize it in production whenever it happens to be windy. This feature leave the intermittent producers equally unable to strategically adjust their supply to short-term changes in the market as the thermal producers (Førsund, 2005). The market effect of this intermittent production is a stochastic positive shift of the supply curve, which, all else equal, reduces the equilibrium prices in the market. Since both thermal and intermittent production sources are difficult to adjust to the current market situation, hydropower is important for maintaining a stable electricity price and correcting for unpredicted events.

2.1.3 Hydro-based energy production

Hydropower is the most flexible source of electricity production in the market. The inherent storability characteristics of water, along with negligible production costs, bestow owners of hydro plants with a unique ability to adjust their output in response to short-term market conditions.

A typical hydropower plant consists of a water reservoir that is enclosed by a dam, and a power house that contain water turbines that power a generator, which is what creates the electricity. In this model, the potential for electricity generation is determined by the height of the fall from the dam to the turbines, the size of the production equipment and the size of the reservoir. Gravity is the only fuel needed to realize this energy, while salaries and maintenance costs are best considered fixed with regards to production output. Variable costs of production are thereby rendered irrelevant in their production decision (Førsund, 2005).

Norwegian reservoirs account for about half of the European total storage capacity for water ("Om kraftmarkedet og det norske kraftsystemet", 2015). Larger reservoirs provide the producers with more flexibility in their production decision, as water can be stored across longer periods without breaching environmental regulations on upper and lower filling levels. Hydro-based power markets with more reservoir than run-of-the-river plants will be equipped to handle unusually dry periods, and even more so if the majority comes from big reservoirs. As an example, the Norwegian market sustained through the dry years of 2009 and 2010 through water stored from previous years and increasing their import from neighbouring countries where thermal sources are more prevalent.

For most of the year, the production is higher than the inflow. A few months of late spring and early summer typically fill the reservoirs with 2/3 of the yearly total (Førsund, 2005). Production levels follow the opposite trend throughout the year, mainly because the demand for heating is higher in the colder months. Such demand effects will be explored more in-depth in sub-chapter 2.2. These conflicting trends are illustrated in *figure 2*, which emphasise the importance of being able to store water between periods in order to have a stable supply throughout the year. Large reservoirs are even able to store water from wet to dry years.

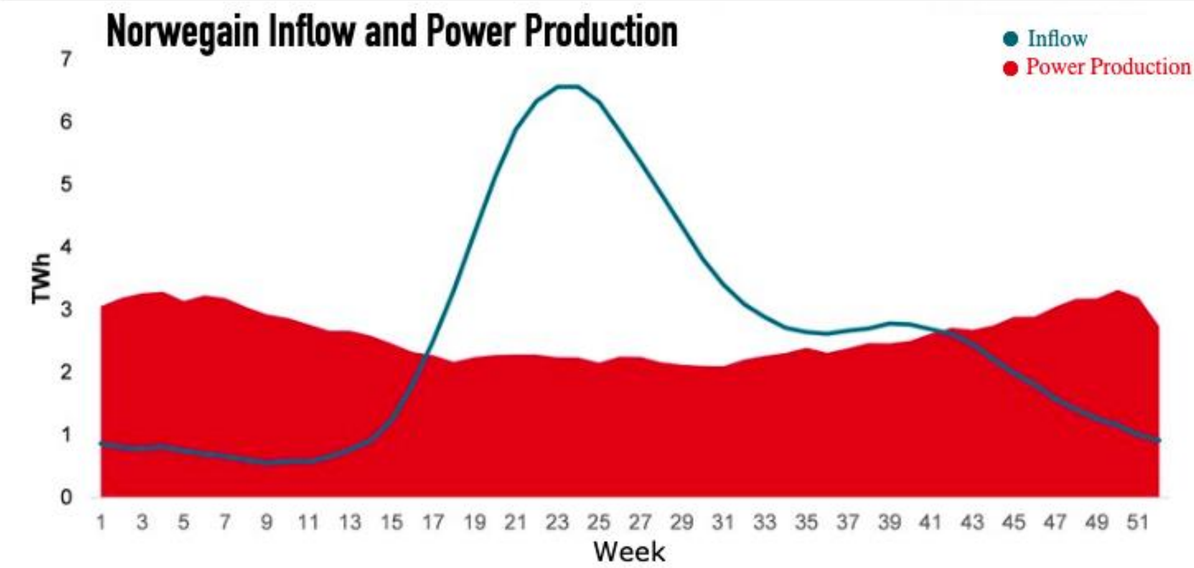

Figure 2: Typical relationship between inflow and power production in Norway. ("Om kraftmarkedet og det norske kraftsystemet", 2015)

The amount of water a given hydro producer dispose in her reservoir at any time is dependent on seasonal factors like rainfall and snow melting, reservoir level in the previous period, precipitation and the amount of water employed in production. This stored water has a shadow price termed *water value* (Førsund, 2005). Variable costs of production like salaries and maintenance costs are best thought of as fixed with regards to production levels. This water value is therefore what determines the production schedule of a hydro producer. Considering that they cannot realistically alter the reservoir inflow, the sole production decision for the owner of a hydropower plant is how to allocate her water in production between different periods to maximize profits. The lack of costs associated with altering production levels invites the possibility of dominant producers strategically manipulating the market prices.

The water value can be interpreted as the relevant short-term marginal cost for these producers. It would in a strictly hydropower-based market be defined as the consumers' willingness to pay in the alternative periods. In a further simplified scenario without reservoir limits and infinite production capacity, the optimal production plan would instruct a hydro producer to empty her reservoirs whenever the price is highest. However in reality, this profit-maximization problem is complicated by bottleneck factors in production like limits to reservoirs and production capacities of key equipment, varying efficiency of the turbines for different production levels, and the marginal production costs of other energy sources. These factors will all influence the water value to some extent. There are also significant differences in inflow between years, and it is very difficult to accurately estimate the inflow of future years, months or even weeks. This uncertainty further complicates the production decision of hydro producers with regulated reservoirs [for a far more thorough discussion on this topic, see Førsund (2005)]. The real production decision of the hydro producers is thus a dynamic optimization problem dependent on uncertain marginal costs and demand responsiveness across several periods. Being able to accurately estimate future demand, and demand elasticities is thus critical for profitability.

Economic theory dictates that suppliers with market power are incentivized to exploit variations in demand to diverge their production from the social optimum. For hydro producers, this means leveraging flexibility in production to attain additional profits through withholding water in their reservoirs in periods when the market demand is more inelastic. In this way, they can ramp up the equilibrium prices when the customers are least inclined to respond by reducing their consumption. This practice will be profitable as far as the increased revenue from getting a higher price on all their inframarginal units more than covers the lost revenue from the negative effect on demanded volume induced by the increase in prices (McDermott, 2019).

In Nord Pool this exertion of market power is likely to be more potent in circumstances where binding transmission constraints isolate smaller bidding areas. Within these geographical bidding areas prices might increase far above the system price, and the temporary market power of a single producer can be much higher than when transmission constraints are not binding. These bidding areas are only formed when demand in the area outweigh the supply with more than the installed transmission infrastructure allows to be imported from neighbouring areas. If a producer expects such a situation to occur, this can also affect the production decision.

Non-competitive behaviour of major hydro producers will be examined theoretically in chapter 3 and empirically throughout chapter 5 and 6. Before that, I will introduce the key characteristics of the demand-side.

2.2 Demand

The demand for electricity in the Nord pool area follows a largely predictable pattern throughout the hours of the day, days of the week, and seasons of the year. Furthermore, temperature is a very important determinant of the consumption level at any given time.

To better understand the characteristics of the demand in this market, it is useful to separate *Household* and *Non-Household Consumption*. The latter category captures industrial, commercial and public service related end-uses, while the former consists of mainly space heating, lighting, use of electric utensils and heating of water in private homes. *Figure 3* visualizes the consumption distribution in Norway for 2016. Akin to the supply mix, it is however fairly stable from one year to the next, as illustrated in appendix 1.

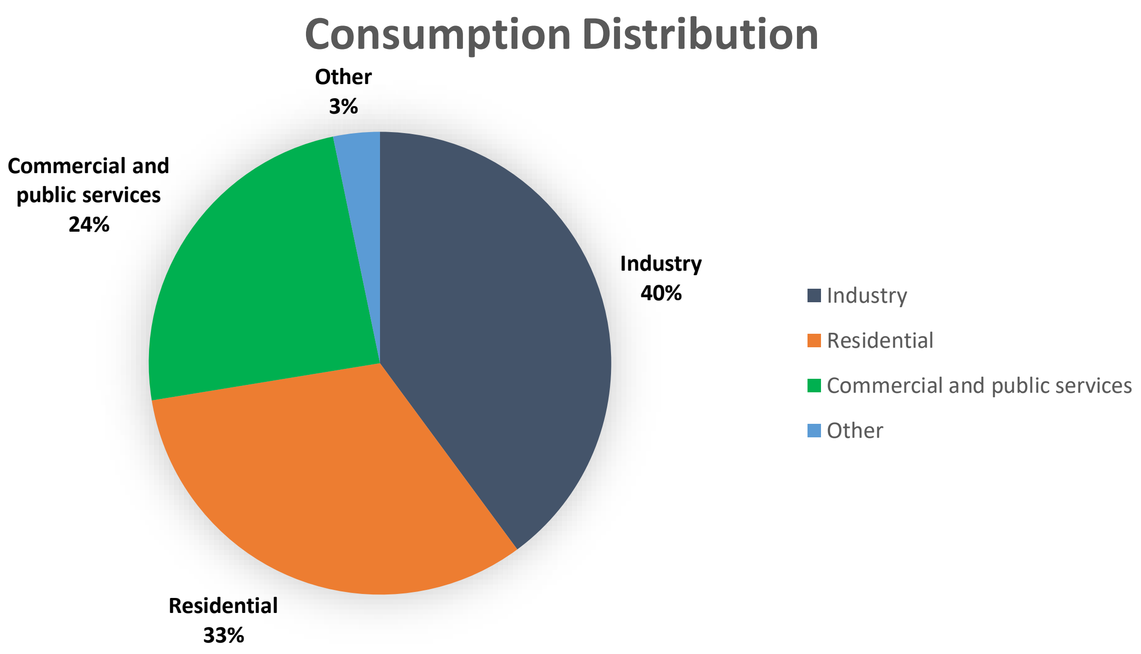

Figure 3: Nord Pool Consumption Distribution (2016)

2.2.1 Non-household demand

The manufacturing industry and service providers typically run from the morning through the afternoon on every weekday and is idle on the evenings, nights and weekends. These effects are recognizable in *figure 4* and *figure 5*. The former illustrates the volume cleared on Elspot throughout a randomly sampled day, while the latter shows the weekly volume pattern for a randomly sampled summer week. A corresponding graph for a sampled winter week is found in appendix 2. The winter trend shows a similar pattern, but the prices are significantly lower. Observe that volume tends to be lower during the night time and for weekends. An exception is heavy industry, where production only shuts down for extraordinary events like maintenance and unplanned break-downs. Some of these large industrial players bid their desired consumption into the market in the form of block bids. It is reasonable to assume that the development in general economic activity will influence the demand for electricity through expanding the consumption from non-household end-users. In lighter industries electricity is mainly used for heating purposes, lights and running work equipment. This is assumed to be a highly inflexible form of end-use as rising spot prices are not likely to make many businesses shut down or even alter their operations (Førsund, 2005). Conclusively, periods and markets with a high share of non-household consumption are assumed to be characterized by a more inelastic demand. This assumption is also used in the study by Bye and Hansen (2008).

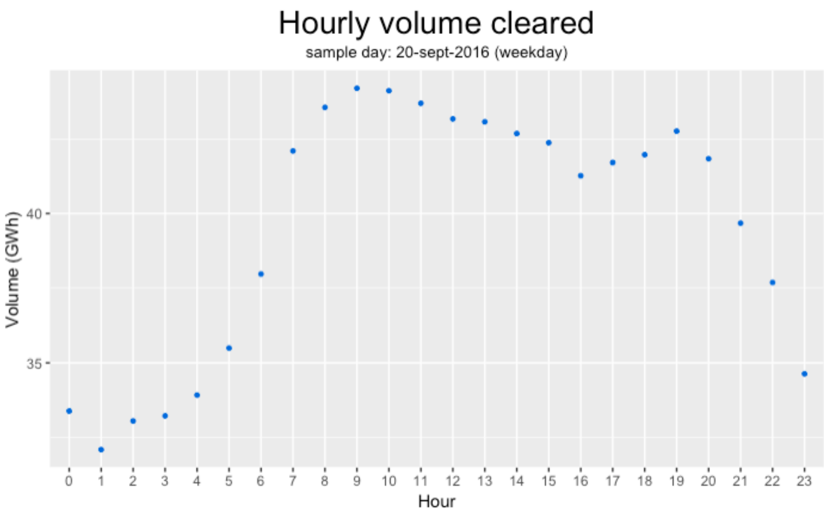

Figure 4: Hour-of-day trend for quantity cleared on the Nord Pool Elspot market

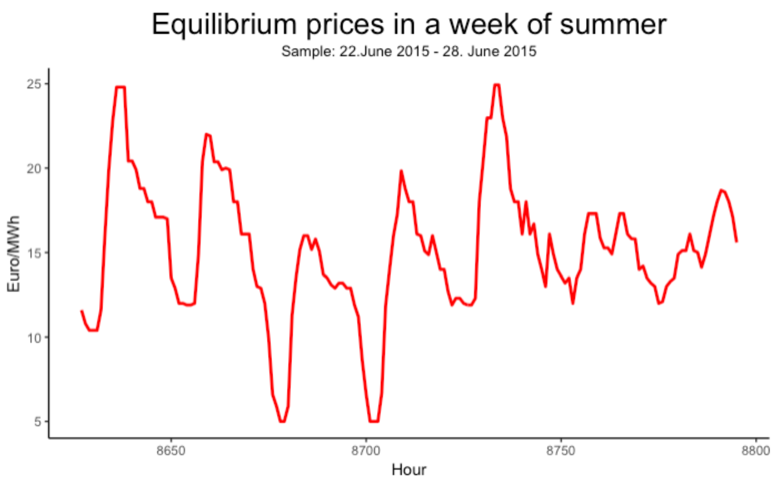

Figure 5: Variation in hourly spot prices across a randomly sampled week of summer

2.2.2 Household demand

There are some seasonal variations, but household consumption constitutes about one third of the energy consumption in Norway throughout a given year. This end-use also largely follows a predictable pattern induced by nocturnal sleeping norms, a peak for heating and making of breakfast around 7-8 AM, a slight dip while people are at work, and finally an increase in the period from 4 PM to 10 PM as people cook dinner, re-heat their houses and use electric entertainment systems (Bye and Hansen, 2008) This is also reflected in *figure 4*.

According to a study by Dalen and Larsen (2009), heating make up about 20% of the annual energy consumption in Norway during a given year. This figure is closer to 30% in the winter months when temperatures are lower. Nearly 40% of Norwegian households have non-electric substitutes for heating. It is therefore common in the literature to assume that household consumption is more responsive to changes in spot prices than non-household consumption, as prolonged periods with high electricity prices will incentivize consumers to increase the usage of alternatives like wood stoves, oil burners and paraffin heaters. A subsequent implication is that demand will be more elastic in winter months. The data supports this assumption, as shown in *figure 6* which is inspired by McDermott (2018). The demand is shown to be most elastic in November, least elastic in June, and in general more elastic in the colder months of the year.

Consumption is roughly double that of the summer months during the cold part of the year (Bye and Hansen, 2008). That the flexible end-use, through heating, constitute an even larger share of the total electricity consumption in these cold months of the year is natural. Inflexible technical end uses will in contrast be comparatively more prominent in the summer months. The implication is that when the share of flexible end-uses increase, the demand will also be more elastic. This is expected as the consumers on average will be less reliant on electricity when a larger share of the end-use can be substituted by other means of heating if the prices severely increase. These private homeowners do not directly buy electricity from the wholesale market, but the retailers compete and wholesale spot price is a key determinant of the prices facing the consumer (Fleten and Pettersen, 2005). In conclusion, the composition and characteristics of total energy consumption systematically differs across hours, days and seasons.

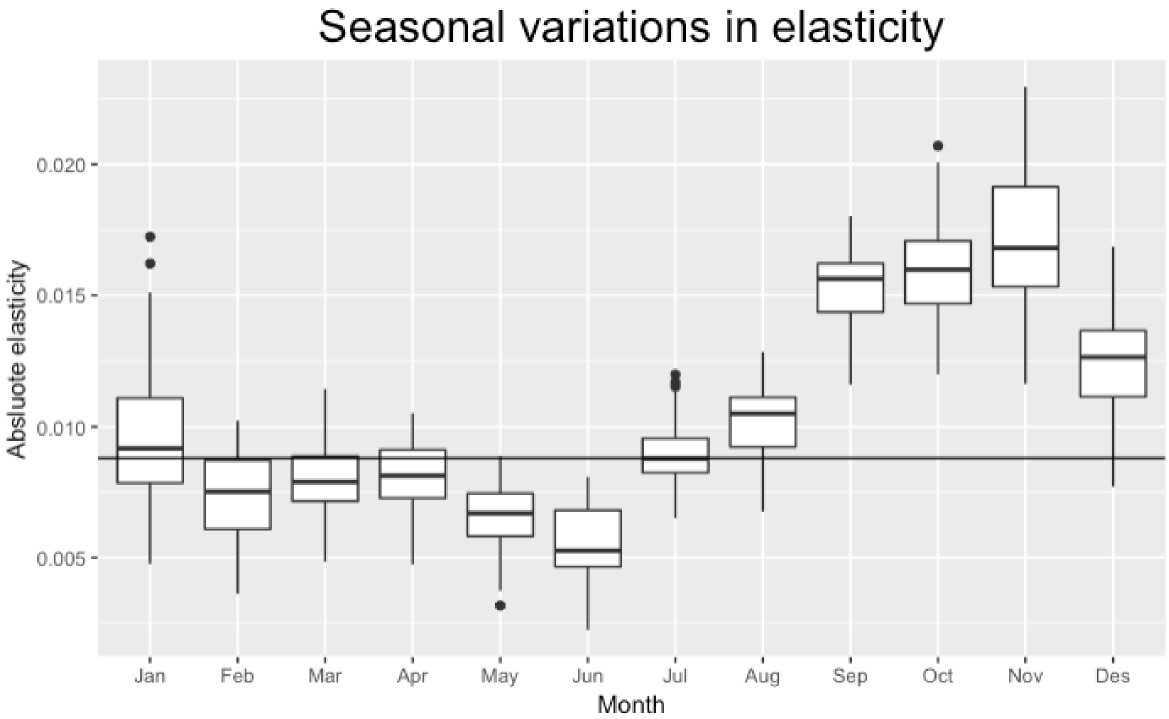

Figure 6: Overview of demand elasticity across seasons.

Note: Estimates are attained by regressing daily arc elasticity values from my sample, on monthly dummies and controls. The horizontal line highlights the median estimate, and thus separates the months characterized by relatively elastic and relatively inelastic demand.

3. Theoretical Framework

I will in the following provide a theoretical account of the implications of market power on the dynamics of a hydro-based electricity system. Akin to the approach by McDermott (2018), the argument will follow the more general examples made by Finn R. Førsund in Hydropower Economics (2005). The underlying idea is that the presence of market power on the production side will diverge the equilibrium from the social optimum achieved in a free competition scenario.

For an intuitive account of the phenomenon, consider the profit-maximizing function of a hydro producer that acts as a monopolist in an isolated market, and who operates with no uncertainty or reservoir constraints across only two periods:

$$max \sum_{t=1}^{2} p_t(q_t) * q_t \tag{1}$$

$$s.t. \sum_{t=1}^{2} q_t \leq W \tag{2}$$

Where p_t and q_t are the price and volume demanded for electricity, W_t the GWh-equivalent of the endowment of the producer's reservoir at time t. $p_t(q_t)$ is the inverse demand function facing the monopolist with the standard property of price decreasing in volume, in accordance with the law of demand. The maximization problem is subject to the constraint of the producer not being able to utilize more water than are currently available in her reservoir. The necessary first order conditions (FOC) of this maximization problem are then:

$$\frac{\partial L}{\partial q_t} = p_t'(q_t)q_t + p_t(q_t) - \lambda \leq 0 \tag{3}$$

and

$$\lambda \geq 0 \tag{4}$$

$$(\lambda = 0 \quad for \quad \sum_{t=1}^{2} q_t < W).$$

λ refers to the water value, which, as previously stated, reflects the shadow price of the water stored in the hydro reservoir. It will thereby only have a positive value in the cases wherein the production constraint (4) is binding. Through assuming that the monopolist is expending all the water across the two periods, without depleting the whole endowment in a single period, the FOC can be stated as:

$$p_1(q_1)\left(1+\frac{1}{\varepsilon_1}\right) = p_2(q_2)\left(1+\frac{1}{\varepsilon_2}\right) = \lambda. \tag{5}$$

Here, ε_t refers to the non-absolute price elasticity of demand. Maintaining the assumption of a downward sloping demand curve, a rearrangement of this condition makes it clear that the monopolist solution is conditioned on the relative price sensitivity across the two periods. As an example:

$$q_1 < q_2 \qquad \text{if} \qquad |\varepsilon_1(q_1)| < |\varepsilon_2(q_2)|.$$

The monopolist will optimize her profits by limiting production – thus inflating the equilibrium price – in periods with comparatively inelastic demand. This stratagem will always increase her profits, as the consumers, per definition, will respond with the smallest contraction of demand in this period.

In a market characterized by free competition on the other hand, the prices will be equal in all periods. Considering that in a fully competitive market the demand is perfectly elastic (i.e. $\varepsilon \to \infty$), it is straight forward to see from (5) that the optimal social solution in our example is achieved through prices that are equal to the water value and constant across the periods:

$$p_1(q_1) = p_2(q_2) = \lambda \tag{6}$$

This corresponds to Hotelling's rule for the model of the market with perfect competition (Tirole, J., 1988). There is no discounting nor uncertainty in this example, and the transferability of water is unlimited. Consequently, the social price in the market must be constant across periods by arbitrage of the endowment of the sole and finite production resource, water. The assumptions also ensure that there is only one shadow price. In a scenario where prices are imbalanced, transferring water to the period with the highest price will increase profits until the social optimal solution of equal prices across the planning period are regained.

The implications are that the supplier in a monopoly market will produce less than the social optimum in periods of relatively inelastic demand and higher volumes in the more elastic periods:

$$q_1^M < q_1^C \qquad \text{and} \qquad q_2^M > q_2^C \qquad \text{if} \qquad |\varepsilon_1(q_1)| < |\varepsilon_2(q_2)|.$$

This is a drastically simplified scenario, but it carries the essential idea. I again refer to Førsund (2005) for a more in-depth explanation of how the market power effect is amplified or reduced by the introduction of a range of complicating factors. Therein, the motivated reader is entertained to how multiple periods and competitors, as well as different restrictions on the production capacities, alternative production means, trade and uncertainty affect the general concept demonstrated above. The substantive result in the simplified case does however hold. Profit optimizing hydro producers with market power will employ a strategy of allocating production away from periods with relatively inelastic demand in order to ramp up the prices when the customers are less inclined to respond with substantial demand contractions. This motivates the following proposition:

Proposition: My testable hypothesis is that the market will clear on higher prices in periods of relatively inelastic demand.

4. Data

I construct a dataset mainly based on publicly available data from *Nord Pool, The Norwegian Water Resources and Energy Directorate* (NVE), and the Norwegian public transmission system operator, *Statnett*. In addition, temperature data from *the Swedish Meteorological and Hydrological Institute* (SMHI), and *the Norwegian Meteorological Institute* (MET) have been used. Throughout this chapter I will describe the original data from these sources, as well as the methods and assumptions employed in their consolidation into a unified dataset.

The aggregate hourly system supply and demand bid curves from the wholesale day-ahead market are collected from Nord Pool's public database. I am grateful to my supervisor, Morten Sæthre, for providing me with a processed version of this information. There are about 750 and 400 quantity/price pairs on the supply and demand curves respectively per hour, which accumulates to approximately 25.7 million observations across the period from July 1st 2014 to December 31th 2016. Block bids and net import or export from the market have also been downloaded from the same source. The accepted block bids and data on the hourly import and export flow for the area are used to adjust the bid curves so that the final step of the Nord Pool clearing algorithm can be accurately reproduced.

4.1.1 Quantities and prices

The increasing supply and falling demand curves will intersect at a given quantity and a given system price for every hour. There might not always be a specific quantum-price bid at the exact equilibrium values on both aggregated curves, as Nord Pool linearly interpolates the stepwise bid curves. In these cases, I used the mean of the two price and volume values that were the closest across the two curves. The resulting 21.979 hourly equilibria were on average 38.9 GWh, while the prices span from 1.1 to 200 €/MWh, with an average of 25.4 €/MWh. Extreme prices like €200 are exceptions, only about 0.75% of the observed equilibria cleared at spot prices higher than €50. That prices can shoot up when demand is very high and/or supply severely limited is a result of the underlying structure of the market. In these periods, the most expensive means of production like turbines fuelled with natural gas are mobilized. Since the whole market clears at the price set by the auction, which again reflects the marginal cost of the most expensive power source utilized, these extreme cases can occur in some extraordinary circumstances. The *figures 7* and 8 demonstrate this point visually. It is also further elaborated on through an in-depth exploration of some extreme observations, at the end of this chapter. *Figure 7* shows the aggregate supply and demand curves for a fairly regular day on the market, while *Figure 8* in contrast shows how prices can shoot up demand is high enough to motivate producers to employ more expensive means of production.

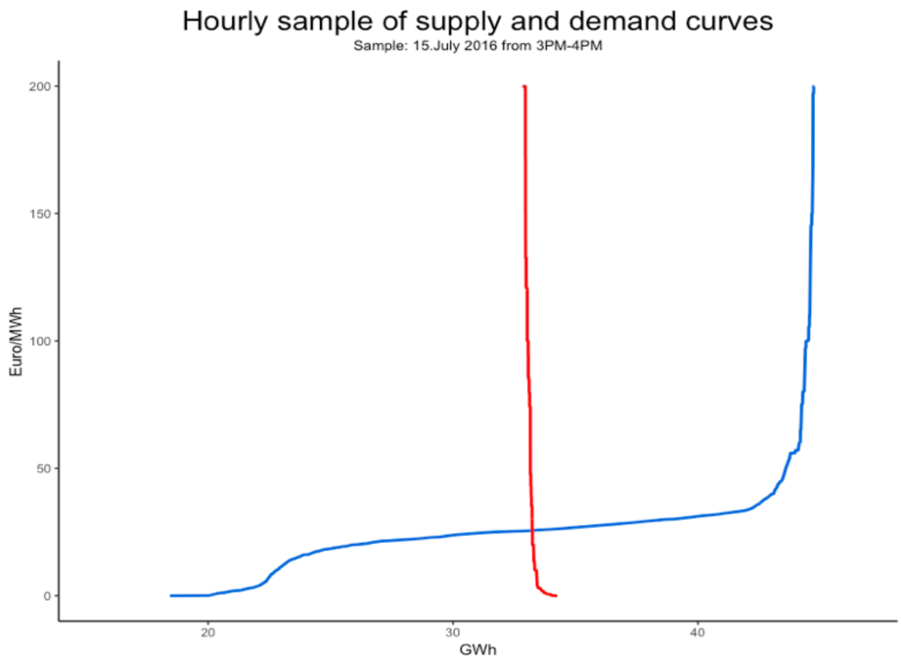

Figure 7: aggregate supply and demand curves for an hour with ordinary demand

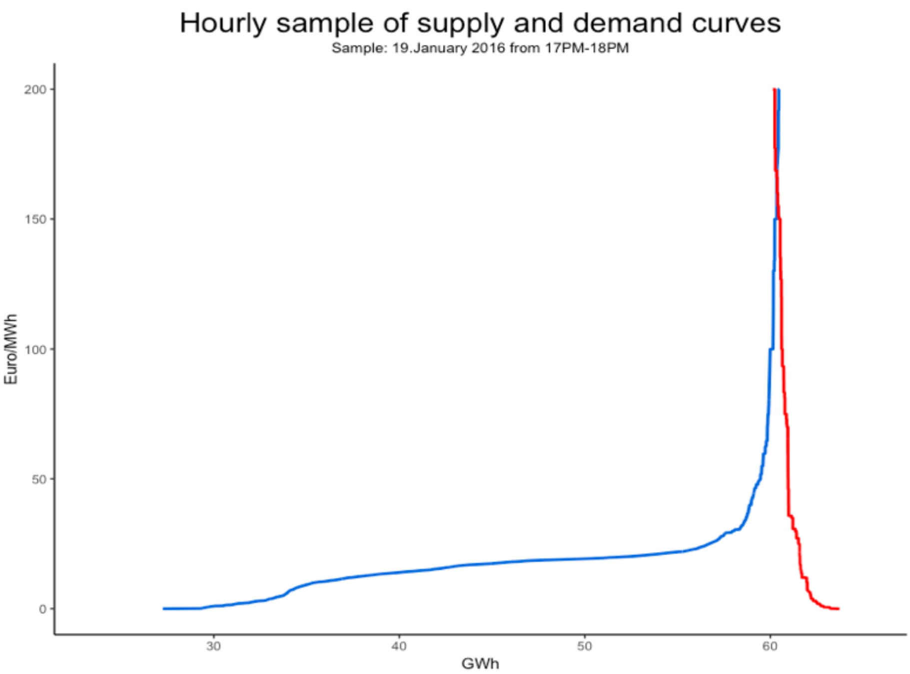

Figure 8: aggregate supply and demand curves for an hour with very high demand

4.1.2 Demand Elasticity

The demand elasticity variable captures the price responsiveness of the demand side in each hourly equilibrium point. Electricity is a fully homogenous necessity commodity, and consequentially the demand in the market is highly inelastic. My metric ranges from practically zero to 0.113 in absolute value within the sample period. I have calculated it as the arc elasticity around each equilibrium point using the real demand-side quantum-price bids closest to a 10% positive and negative deviation from each observed equilibrium price. Mathematically this can be written as:

$$E_p^{arc} = \left| \frac{\frac{q_2 - q_1}{q^*}}{\frac{p_2 - p_1}{p^*}} \right|,$$

where q_2 is the volume demanded at the higher price, p_2, and q_1 is the volume demanded at the lower price, p_1. q^* and p^* are the actual quantity and price in the equilibrium. A problem with this approach is that when the bid closest to 10% deviation from equilibrium still is the equilibrium, the denominator will be zero and the demand elasticity will be undefined. This concerns about 6% of the equilibria, and I have chosen to remove the observations because it is unclear how elastic the market was around these scarce bids. Furthermore, increasing the bandwidth to 15% deviations did not solve the problem and the specification provided a less smooth elasticity trend. The remaining number of observations is 20.638.

As shown in *figure 6* the price elasticity of demand follow a seasonal trend in the data. In the winter months, a larger share of consumption is used for heating, which is a more substitutable form of end-use, while summer months are more dominated by inflexible technical end-uses. Consequentially, demand is more elastic in the winter months.

In general, the demand-side appear to be most price-responsive around common equilibrium values. This is visually demonstrated by *figure a* in appendix 3. There is however an increase at high prices as well, but at these price levels the amount of observations are very low. One would assume that very high prices would be met with an even more responsive demand, as consumption would be reduced to only the bare necessities. Limiting factors in this direction might be that unusual equilibriums occur under circumstances like very cold weather, and that most consumers are unwilling to reduce their consumption by much even at very high prices. Another plausible cause is that uncommon equilibrium values occur quickly due to unpredicted events, while market effects bring the prices back to normal quite fast as well. Thereby the demand side is not able to react to the price changes before they are normalized.

I further find that the elasticity follow a similar trend as quantities and prices throughout the hours of the day. A trend shown in *figure b* of appendix 3. The nightly demand is more inelastic, while the price responsiveness is highest during the busy morning hours and the early hours of the evening. This pattern is also found in the study by Bye, Hansen (2008). They explain the mid-day surge as businesses being a more dominant part of consumption in these hours, and that this mode of consumption is more price-responsive than household consumption. They also recognize that substitution possibilities argue the opposite point, as I entertained in sub-chapter 2.2. That the night hour consumption is less responsive is natural as primarily inflexible heavy industry and modest heating devices for private homes are active while most people are asleep.

4.1.3 Temperature

I am indebted to Erik Lundin for providing me with temperature data for Sweden. The original source of this data is SMHI. The Norwegian equivalent is downloaded from the weather service, Yr.no, which is operated by the Norwegian Meteorological Institute. The data is reported for 21 temperature stations across Norway and the largest city in each of Sweden's four bidding zones across the same period.

The final temperature variable is calculated as the average temperature of these cities for any given hour. This variable caries the predictable features of being higher during the daytime than the night and higher in the summer months than in the winter months. Table 1 on page 26, which reports summary statistics, shows that the average temperature across the period was just above 10 degrees Celsius. The most extreme average temperatures observed is -13 degrees on the cold side and 30 degrees at the hottest. Owing mainly to the widespread usage of electrical energy for heating in the region, the relationship between temperature and demand is negative. Air condition on hot days is much less common. There was a handful of missing values throughout the temperature data, these gaps have been interpolated.

4.1.4 inflow

I have downloaded weekly data of the inflow into 82 Norwegian hydro reservoirs from NVE. The freely available data is unfortunately measured in average cubic meter per second and not the potential electrical power that it can produce. This makes comparisons to cleared market volumes difficult. Nevertheless, I have aggregated the data into a total value for all reservoirs; this should still give a decent indication of the effect on water value in my analysis. The average weekly inflow was 1.228 cubic meters per second in the period. The average value is however not very informative, as the inflow is highly season-dependent. This is illustrated by the highest recorded inflow being almost 20 times larger than the lowest, as shown in Table 1.

Since different reservoirs have different height from the dams to the turbines, the same inflow measured in cubic meters can have different values in terms of potential electrical power produced. In the engineering literature [see Frisch (1965) and Loucks and van Beek (2005) for examples], this relationship can be described by the following production function:

$$Q_t^H \leq \frac{1}{a_t} w_t.$$

Q_t^H is the electrical power produced at hydro plant H at time *t,* w_t is the amount of water and $\frac{1}{a}$ is a plant-specific *production coefficient,* that is based on factors like the height and steepness of the installed pipe system, fullness of the reservoir, friction and efficiency of installed turbines (Førsund, 2005). This conversion will not be further pursued in this paper, instead the data in cubic meters per second will be used in the analyses, and a publicly available figure (*figure 2*) from NVE was used in sub-chapter 2.1 to illustrate the relationship between production and inflow.

4.1.5 Supply From Non-hydro Producers

Data on wind production have been downloaded from Nord Pool's servers, where it is openly available in the same hourly format as the bid curves. The wind production is determined by the stochastic external factor of how strong the wind is blowing at the given hour. The wind production constitutes about 8 percent of the total supply in the market across the sample period.

The prices for coal and carbon dioxide emissions are important determinants of the marginal costs in thermal power plants. When these prices increase the production volume in coal and gas plants are going to be less profitable and supply contractions are expected. The prices are denoted in euros per metric ton and reported daily. The data is collected from Trading Economics' database for coal. The CO_2 price is the European Emission Allowances (EUA) primary market spot price, which is gathered from the European Energy Exchange (EEX).

Descriptive Statistics

Statistic	Mean	St. Dev.	Min	Max
Price	25.424	8.758	1.112	200.000
Demand Elasticity	0.011	0.012	0.000	0.113
Quantity	38.890	7.690	22.634	71.301
Wind Production	3.325	1.920	0.072	9.658
Temperature	10.050	6.823	-13.300	30.200
Coal Price	39.759	3.408	34.570	50.610
CO2 Price	6.408	1.230	3.940	8.630
Inflow	1,228.030	759.050	198.661	3,654.252

Volume and wind producion are denoted in GWh,
Price is in euro per MWh, Temperature is in Celsius and
Reservoir inflow is in cubic meters.
Coal and CO2 prices are in euro per metric ton
Observations run hourly from 1.jul.2014 to 31.12.2016, N = 21,979.
N = 21,979 for all variables except inflow which is measured weekly

Table 1: descriptive statistics for key variables

4.1.6 Extreme equilibrium observations

The most extreme quantity values observed in the period was 22.6 GWh on the low end and 71.3 GWh at the highest. This peak value is the all-time record volume traded on Elspot for a single hour and was recorded on January 21th 2016 between 10 and 11 AM (Johansen, 2016). This extreme value reveals a lot about how the market functions. January 21th 2016 has the lowest recorded average temperatures in the data set, no precipitation and limited wind production. The frigid temperature will shift the demand curve outwards since consumers will increase their electricity usage on spatial heating. This effect creates a strong negative correlation between the temperature and quantity variables (Bye and Hansen, 2008).

The reduced wind production from intermittent wind producers will shift the supply curve inwards. We also see that the highest clearance price in the data also occurs on this day, in fact all the 30 highest recorded system prices are from this same cold week in January 2016. 10-11 AM is also a time of the day when demand for electricity usually is high. The lack of inflow could further contribute to lower the supply and thus drive up the price if hydro producers are incentivized by depleted water reservoirs to limit their production. This effect is however only realized if it rains or snows less than expected over a period, as expected dry spells will already be accounted for in the shadow price of stored water (Førsund, 2005). Contrary to this example, both the lowest system price and the lowest cleared quantum occurred on warm days in July.

The price peaked at almost 10 times the average system price. Intermittent overproduction can potentially lead to the market clearing on negative prices, but this never happened in the sample period. The large share of stable base load thermal and hydro producers in the market ensure that negative system prices due to overproduction is unlikely in Nord Pool. The many different energy sources and geographically spread consumer market serve to guard the market against most of the very extreme equilibriums. These are more likely to be observed within isolated temporary bidding markets within the main market, but in the long-term these problems will also be addressed through improving the transmission infrastructure or supply capacity. The system price variable is still skewed, as the only upper limit is set by the willingness to buy, which is very high for an important good like electricity. On the low end, the price is restricted by marginal costs, which for the dominant power sources in the market will be positive in all periods.

5. Empirical Strategy

In light of my theoretical proposition, consider the model:

$$P_t = \beta_0 + \beta_1 Q_t + \beta_2 Elast_t + \beta_3 X_t^S + \beta_4 X_t^D + v_t + \varepsilon_t$$

where the subscript t denotes an index for sample hour. Spot prices P_t are explained by changes in cleared volume Q_t through β_1 and the market power effect is captured in β_2, which denotes the effect on price from changes in the responsiveness of demand. X_t^S and X_t^D are vectors of supply and demand controls, while v_t is a vector of time-fixed effects and ε_t the econometric error term. Heteroscedasticity and autocorrelation consistent (HAC) standard errors are estimated through the Newey-West procedure.

Fixed effects: In order to accommodate for the unobserved seasonal patterns of electricity consumption, fixed effects for each sample week are included in the model. This specification also reduces the identifiable variation from unobserved time-variant factors like general economic activity and the volume of financial forward contracts in the electricity market. A second model where sample month fixed effects are included because data on the key supply shifter, reservoir inflow, are only available in a weekly format.

Additionally, a weekend dummy is used to account for the structural differences in the consumption pattern between weekdays and weekends. The nature of these differences was more thoroughly examined in sub-chapter 2.2.

Controls: These are observed factors that are not of direct interest in the study, but are included in the model to account for their potentially biasing effect on the relationship between demand elasticity and spot prices.

The hourly amount of wind production in the market is included as a control. As previously elaborated, intermittent wind production shift the supply curve outwards, along the falling demand curve, thus reducing the spot price. A weaker counteracting effect is also expected when wind production increases, as poorly isolated buildings require more heating on windy days, so that it also captures a positive shift in demand. The wind production variable is thus included in both the vector of supply and demand controls (Lundin and Tangerås, 2017). However, the net effect of increased wind production on spot price is expected to be negative, as the expanding supply effect is likely more dominant than the demand effect. This should imply a negative parameter for the wind variable in the results of the main regression.

In addition to hydro, wind and the steady nuclear production, coal and gas are critical parts of the supply mix in the Nord Pool area. The marginal production costs of these market actors are naturally reliant on the prices of their input resources, and the extra costs associated with the carbon emissions their mode of production entails. These costs are relevant because they increase with the production level and thereby affect the marginal production decision. An increase in the prices of these resources would increase the marginal cost of supply, reduce the optimal production level, and so contract the supplied quantity. This should make the market clear on a higher system price. A positive effect on price is expected. However, the weekly dummies are likely to dampen the effect, as these prices typically don't vary too much within a single week (Lundin and Tangerås, 2017).

In the model with sample month dummies, reservoir inflow is controlled for because it increases the reservoir level of the hydro producers and thus incentivize them to expand their production, which ceteris paribus will reduce the equilibrium price in the market. As explained in more detail in sub-chapter 2.1, the shadow price of stored water represents the alternative costs of production for actors that use hydropower in their production. When the reservoir inflow positively deviate from what is expected, the hydro producers will increase their production and vice versa. This positive supply shift should move the equilibria down along the demand curve and thus have a negative effect on the spot price in the market. Additionally, snow-melting is an important component of yearly inflow, which implies that it will also be correlated with the demand side through temperature. In the weekly model this inflow effect is attempted captured through including temperature and precipitation in the model.

Instruments: There is an inherent simultaneity problem between the volume cleared in the market and the system price at which it clears. In addition, the demand elasticity being affected by the system price will create reverse causality in the model. An OLS-estimation of the proposed model will therefore produce biased parameters. In classic supply/demand fashion, price and volume is decided simultaneously in the market and are thus both endogenous in the model. Contracting production will shift the supply curve to the left, which will always drive up the equilibrium price in a market with a falling demand curve, all else equal. This is especially true in markets for essential commodities like electricity, where limited supply potentially can lead to dramatic increases in price due to the consumers' low price sensitivity. Furthermore, the customer's responsiveness to price is also likely dependent on the price level.

High prices create news headlines and startling electricity bills that can trigger an urge to pay closer attention to developments in the prices, the result will then be a more elastic demand at times when market prices are high.

To circumvent these sources of endogeneity I employ temperature and hour-of-day dummies as instrument variables for quantity cleared and demand elasticity in a two-stage least squares estimation on spot prices. A valid instrument variable must fulfil three key criteria. It cannot be correlated with unobserved factors, it must be correlated with the variable it is instrumenting, and it cannot affect the right-hand-side variable in the main regression through any other channels than its effect on the instrumented variable. These restrictions are called exogeneity, relevance and exclusion respectively. In the following I will argue for the validity of the average temperature across Norway and Sweden primarily as an instrument for the volume cleared in the Nordic electricity market, and hourly dummies as an instrument primarily for price responsiveness on the demand side.

5.1.1 Model with sample month dummies

Temperature is solely a demand shifter in the market, as soon as the inflow into the reservoirs of hydro producers are partialed out. Rises in temperature induce snow-melting that fill the water reservoirs and stimulate an increase in electricity supplied to the market, as previously discussed. There is no apparent reason to think that temperature should dictate how any other electricity producers, like nuclear-, thermal-, or wind-based generation, manages their production. The only channel that temperature affect the spot price is thus through its effect on demanded volume. Since naturally the Elspot prices in no way dictates the temperature, the exclusion criterion is assumed fulfilled for the model with sample month dummies.

Including hours of the day in the first stage equation keeps the exogeneity assumption from being impeded by omitted variable bias. Demand for electricity is higher during the day time irrespective of the temperature, owing to factors like nocturnal sleeping habits, predictable household consumption patterns in cooking and the use of entertainment systems, and also electricity use in industry. Time of the day is for this by this logic confounding the effect from temperature on volume cleared in the first stage regression if hourly variation is left in the error term. Excluding hourly dummies would likely make the model overestimate the effect of temperature on cleared volume, as it would also contain some of the positive demand effect from these correlated non-temperature related factors.

The rationale behind using hourly variation across the day as an instrument for the demand elasticity is that the reverse causal effect from price on price responsiveness is likely to be negligible from one hour to the next, while demanded quantity might shift much more substantially over short time intervals. Furthermore, there is no reason to believe that supply should be systematically different throughout the day.

5.1.2 Model with sample week dummies

Average temperature will shift demanded quantity in a strong and rather predictable fashion, as previously entertained. In the weekly model, I am however unable to directly control for the inflow, which might be problematic with regards to the exclusion criteria of a good instrument. It is however reasonable to assume that the sample week dummies are going to reduce the problem significantly. This because snow melting in the late spring months is a process that happens across several weeks of warm spring weather. If the temperature variable is still correlated with the error term, the quantity effect on price can be overestimated, since the randomization of temperature will capture both the desired contracting demand effect and the seasonal expanding supply effect of rising temperatures. Furthermore, it must be acknowledged that including a temperature variable is not the same as capturing every relevant effect that temperature has in the market. Very cold days in neighbouring countries might as an example induce an increase in demand that I am not able to partial out with my variable for the average temperature across Norway and Sweden. This will be especially problematic at times where densely populated areas are experiencing very cold weather, while the temperature is high in areas that consume less energy. This would lead to the estimated negative effect of temperature on spot prices being underestimated.

6. Results

The regression results are presented in table 2. Column (1) shows the OLS estimates of the model with control variables. The effect of the demand elasticity is estimated to be positive, with the counter-intuitive implications that the market will clear on higher prices when the demand is more responsive. This might be a token of the reverse causality in the model. There is also likely to be an endogeneity problem with the Quantity coefficient in column (1), although a positive estimate is in line with common findings in the literature. That price is increasing in temperature is also as anticipated, since temperature is assumed to primarily be a positive demand shifter. Intermittent wind production is mainly a positive supply shifter, and thus the negative effect on spot prices are as expected. Increased coal prices drive up marginal costs and motivate supply contractions, which ramp up prices in the market. In previous chapters I have argued that prices on carbon emission taxes are likely to have the same effect, but the OLS-estimates in column (1) does not support this case. Precipitation is believed to be a positive supply shifter, and this OLS-estimate is thereby also counter-intuitive.

	Price	Quantity	E	Price	
	(1)	(2)	(3)	(4)	(5)
Demand Elasticity	164.3193***			-19.9610***	-142.2141***
	(3.7271)			(2.8515)	(44.4918)
Quantity	0.8089***			0.7203***	0.8104***
	(0.0140)			(0.0085)	(0.0313)
Temperature	0.3329***	-0.2961***	-0.0001***		
	(0.0146)	(0.0060)	(0.0000)		
Wind Production	-0.6608***	-0.3519***	-0.0005***	-0.5859***	-0.7072***
	(0.0245)	(0.0096)	(0.0000)	(0.0190)	(0.0195)
Coal Price	0.5224***	0.0137	-0.0003	0.2493***	0.1174***
	(0.0140)	(0.0376)	(0.0002)	(0.0741)	(0.0423)
CO2 Price	-1.3060***	-0.0496	0.0001	0.7756***	0.2753**
	(0.0414)	(0.1043)	(0.0005)	(0.2056)	(0.1182)
Inflow					-0.0014***
					(0.0001)
Precipitation	2.2880***	-0.0755	-0.0019***	-0.1510	
	(0.3340)	(0.1074)	(0.0005)	(0.2110)	
Observations	20,638	20,638	20,638	20,638	20,638
R2	0.4710	0.9371	0.4239	0.8105	0.7373
F Statistic	591.8050*** (df = 31; 20606)	1,917.4930*** (df = 159; 20478)	94.7628*** (df = 159; 20478)		

Notes:
***Significant at the 1 percent level.
**Significant at the 5 percent level.
*Significant at the 10 percent level.
Volume and elasticity was instrumented using temperature and hour-of-day dummies.
Sample week FE are included in column 1-4, while sample month FE are used in column 5.
A weekend dummy is included in all specifications.

Table 2: Regression output

Observe that the F-statistic is high for both first stage regressions, this signals the strength of the chosen instruments in a model with only one endogenous regressor. Since this model has two, elasticity and quantity, a Cragg-Donald F-statistic would be preferred. This is however not an option in current R packages.

In an attempt to overcome the exposed shortcomings of the OLS-estimation, a two-stage least square model is presented in column (4). Column (2) and (3) are the associated first stage regressions on quantity and demand elasticity respectively. In column (2), an increase in temperature of 1 degree Celsius is estimated to reduce quantum with almost 300 MWh. Precipitation, and the coal and emission prices have no significant effect on cleared volume. This is likely due to the expected rain already being accounted for in the water value, while coal and emission prices do not vary too much within a given week, and these thermal plants plan their production across longer periods (Lundin and Tangerås, 2017). For the first-stage regression on demand elasticity, presented in column (3), the hourly variation within a day is the primary instrument. The coefficients of the hourly dummies are reported in appendix 4 for the sake of the readability of the table. There is however significant variation in demand elasticity throughout the day, as expected. The high significance of the temperature coefficient can be explained by the explored theme of spatial heating being a more flexible end-use for electricity. In the reverse case, it will thus make sense that higher temperatures are associated with more inelastic demand as warmer days are more dominated by inflexible technical end-uses.

The results of the second stage regression on spot price is presented in column (4). The coefficient for demand elasticity is just under -20 and highly significant. Despite covering an elasticity measure, this variable is interpreted on a level-level basis. Consequently, the parameter value reflects an estimated increase of 19.96 €/MWh in the spot price for a reduction of 1 in the absolute value of the demand elasticity. This is of course far beyond anything observed in the data. It can however be deducted that a reduction of 0.1 in the sensitivity measure, which is about the whole range of variation observed, will be associated with the market clearing on a 1.99 €/MWh higher price, ceteris paribus. Higher market prices in periods of relatively inflexible demand is coherent with dominant suppliers exerting market power to increase profits.

Precipitation and wind production are both positive supply shifters, and the estimated negative effects on equilibrium price are therefore in line with a priori expectations. On the contrary, increases in coal and emission prices will incentivize contractions in supply, which expectedly drives up the equilibrium price, all else equal. All variables in this main specification are therefore of the expected sign, and all but precipitation is highly significant. The limited effect on spot price from increased precipitation might be due to expected rain and snow already being accounted for in the price. If heavy rain is known in advance, it will already be incorporated into the water value, while the times when it rains more than expected, the realization of which might come too late to influence spot prices in the day-ahead market. Precipitation does not have any obvious causal channels it affects spot prices through, outside of changing the water value when deviating from its expectation.

The final column shows a specification where monthly fixed effects are employed, and inflow is directly controlled for. The inflow has a negative effect on spot price, since fuller reservoirs motivate the hydro producers to ramp up their production which will shift the equilibrium down the demand curve. Beyond this, exchanging weekly fixed-effects with the monthly equivalents doesn’t affect the sign or magnitude of most included variables much. The exceptions are that the effect of the coal and emission prices is quite drastically reduced, while the extent of the market power exertion grows about seven-fold.

Both specifications estimate a highly significant negative relationship between demand elasticity and spot price. This leads me to reject the null hypothesis that the Nord Pool day-ahead market was perfectly competitive in the sample period.

7. Conclusion

The aim of this thesis has been to analyze whether hydro producers exerted market power in Nordic day-ahead market for wholesale electrical power in the period from the summer of 2014 to the end of 2016. I have done this through an aggregated test on the effect of demand elasticity on equilibrium spot prices. In accordance with most of the recent literature on the subject (e.g. Bask et al, 2008; Lundin and Tangerås,2017; McDermott, 2019) I find evidence that the prices in the market was influenced by the demand elasticity, which is inconsistent with perfect competition where no market participants are able to affect the prices. It shall be noted that the implications of the market power I have estimated are fairly limited, and should thus be taken primarily as a call for market regulators to be careful in allowing further concentration of ownership in the market.

There are also factors that might act to reduce the exertion of market might even for producers with the opportunity to affect equilibrium prices. That hydropower plants often are at least partially owned by the public sector might limit their exertion of potential market power, as their objectives can span outside of the realm of pure profit maximization. Furthermore, Wolfram (1999) argue that UK power producers limit their exertion of market power to prevent interventions from authorities and the entry of new market participants. Whether these findings are transferable to the Nordic market is not certain, but if so it can explain why I don’t find evidence of even greater strategic manipulations of spot prices.

The current study is performed on the basis of aggregated hourly data, as Nord Pool do not currently disclose bid data on the supply and demand side at a firm-specific level, or even for each bidding area. This information would be very helpful in increasing the precision of similar future studies, as well as uncovering geographical differences in competitiveness in the market. As an example, a strategic analysis of firm-specific behavior when faced with market power enhancing events like binding transmission constraints could be insightful. The publication of more detailed data would in this way give researchers the opportunity to create an even clearer picture of the competitive scene on the Nordic power exchange.

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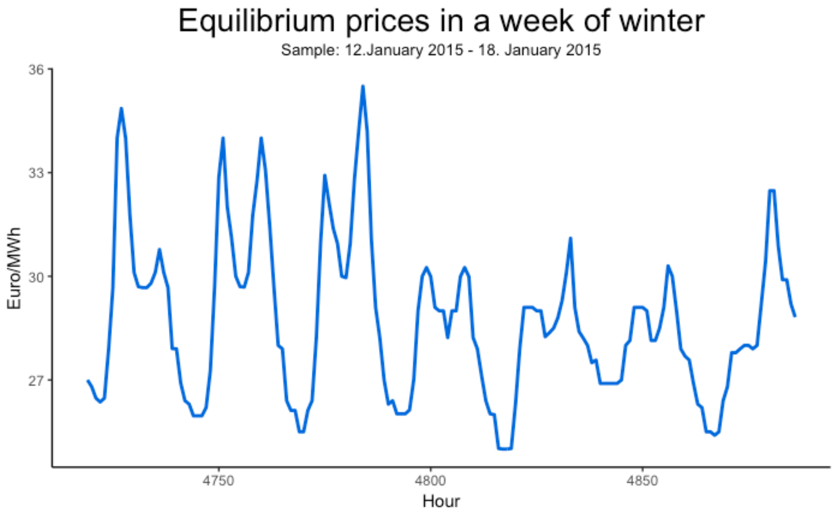
9. Appendices

Appendix 1 – Regional Production and Consumption Data

Electricity	Nordics	Baltics	Nord Pool
Production from:	*GWh*	*GWh*	*GWh*
coal	20 571	10 204	134
oil and gas	10 078	4 480	12 328
biofuels	24 905	2 093	20 870
nuclear	86 304	0	0
hydro*	221 960	3 609	1 044
wind	33 445	1 858	1 136
other	7 651	623	9 725
Total production	**404 914**	**22 867**	**47 414**
Imports	57 113	19 511	11 106
Exports	-61 251	-12 240	-2 831
Domestic supply	**400 776**	**30 138**	**55 689**
Statistical differences	-356	160	0
Transformation**	4 013	5	2 920
Electricity plants	0	0	2 917
Heat plants***	4 013	5	3
Energy industry own use****	21 903	4 656	2 177
Losses	21 379	2 106	5 932
Final consumption	**353 125**	**23 531**	**44 660**
Industry	142 989	7 236	11 326
Residential	116 097	6 481	22 300
Commercial and public services	82 600	8 984	10 553
Other	11 439	830	0

(including Transport, Agriculture / forestry and Fishing)

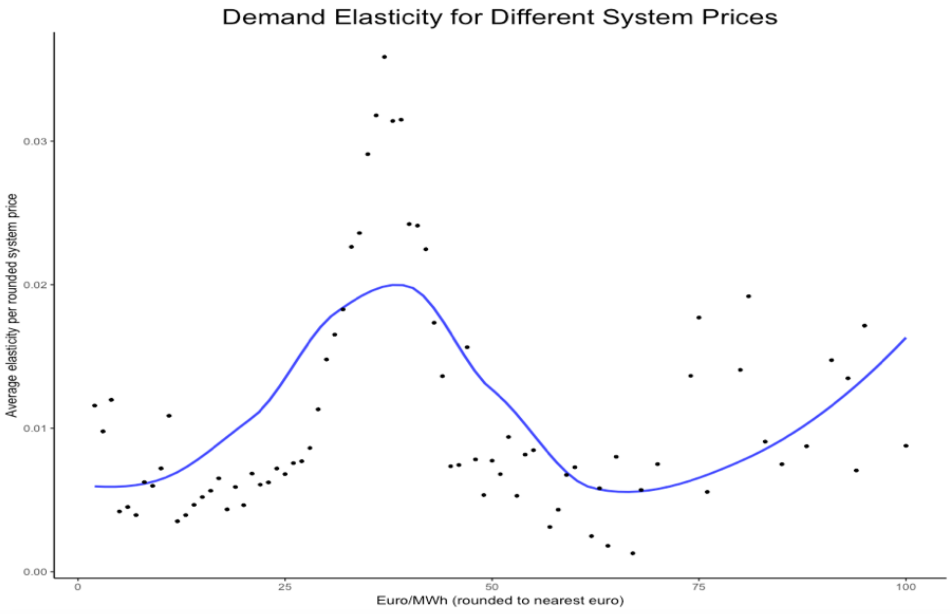
Appendix 2 – Hourly Variations in Equilibrium Prices Across a Winter Week



Like the hourly effect across the summer sample week, the winter equivalent show that there are price peaks in the early morning and afternoon, with a slight dip between. The nightly prices are also far lower than the day-time prices. Finally, weekend prices are lower that weekday prices and the differences between night and day are smaller. The winter prices are however significantly higher than the summer prices.

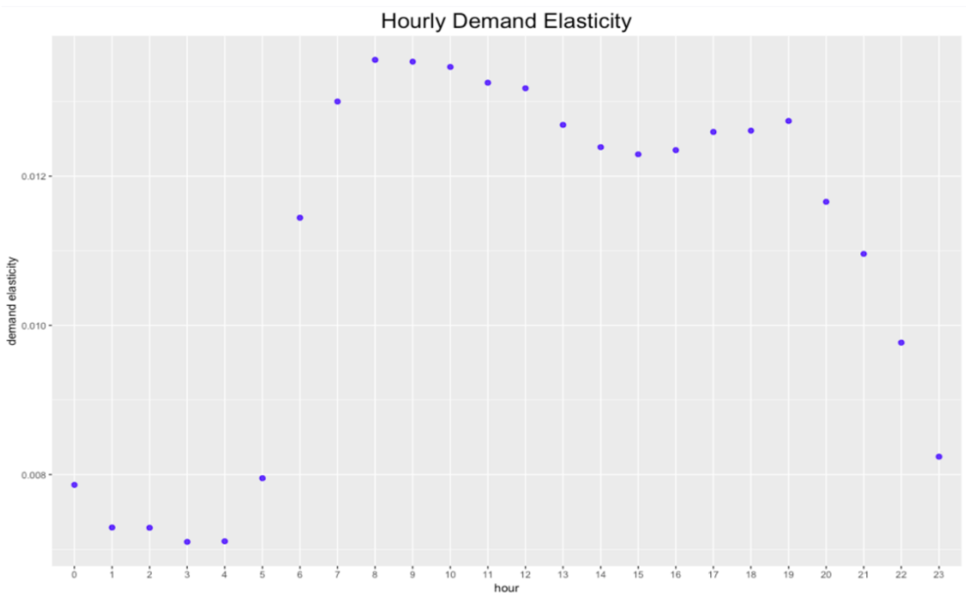
Appendix 3 – Elasticities at different price levels and throughout the day

a)



The average demand elasticity spikes for values just around the most common equilibrium prices, 35-40 €/MWh. This implies that demand is most responsive to price changes around these prices.

b)



Demand is most responsive to price changes at times around breakfast and dinner. This corresponds to the times when household demand is at its highest during the day.

Appendix 4 – Hourly Dummies for First-Stage Regressions with Weekly FE

	Quantity (1)	E (2)
avg_temp	-0.2961***	-0.0001***
	(0.0060)	(0.0000)
wind	-0.3519***	-0.0005***
	(0.0096)	(0.0000)
interp_coal	0.0137	-0.0003
	(0.0376)	(0.0002)
interp_co2	-0.0496	0.0001
	(0.1043)	(0.0005)
rain_mm	-0.0755	-0.0019***
	(0.1074)	(0.0005)
hour1	-0.6918***	-0.0006
	(0.0940)	(0.0005)
hour2	-1.0001***	-0.0006
	(0.0944)	(0.0005)
hour3	-0.8993***	-0.0009*
	(0.0943)	(0.0005)
hour4	-0.4317***	-0.0008*
	(0.0943)	(0.0005)
hour5	0.8955***	0.0000
	(0.0939)	(0.0005)
hour6	3.5760***	0.0036***
	(0.0933)	(0.0005)
hour7	6.6918***	0.0054***
	(0.0939)	(0.0005)
hour8	7.9765***	0.0059***
	(0.0939)	(0.0005)
hour9	8.4737***	0.0059***
	(0.0944)	(0.0005)
hour10	8.8935***	0.0059***
	(0.0951)	(0.0005)
hour11	8.8163***	0.0059***
	(0.0959)	(0.0005)
hour12	8.5848***	0.0058***
	(0.0961)	(0.0005)
hour13	8.3611***	0.0053***
	(0.0962)	(0.0005)
hour14	8.1762***	0.0051***
	(0.0961)	(0.0005)
hour15	8.0735***	0.0049***
	(0.0956)	(0.0005)
hour16	8.1239***	0.0049***
	(0.0951)	(0.0005)
hour17	8.2835***	0.0052***
	(0.0947)	(0.0005)
hour18	7.7901***	0.0051***
	(0.0941)	(0.0005)
hour19	6.8552***	0.0051***
	(0.0936)	(0.0005)
hour20	5.6161***	0.0040***
	(0.0933)	(0.0005)
hour21	4.7183***	0.0032***
	(0.0932)	(0.0005)
hour22	3.1886***	0.0020***
	(0.0930)	(0.0005)
hour23	1.5570***	0.0004
	(0.0933)	(0.0005)
Observations	20,638	20,638
R2	0.9371	0.4239
F Statistic (df = 159; 20478)	1,917.4930***	94.7628***
Notes:	***Significant at the 1 percent level. **Significant at the 5 percent level. *Significant at the 10 percent level.	