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Wind-Generated Congestion and Market Power

Evidence from a Hydropower-Based Electricity Market

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Abstract: Intermittent sources of electricity are gaining market shares in the Nordic region. With wind-power geographically concentrated and separated from high demand regions, the flow of electricity in the grid increases, with congestion of transmission lines as a direct consequence. I illustrate that if large producers in an importing area can predict hours of binding transmission constraints, ability to exercise market power is increased. This thesis tests if hydropower producers in Sweden predict wind-generated congestion to increase prices when import constraints become binding. I find evidence that the dominant producer in Sweden produced relatively less than its smaller competitors during congested hours in 2015 and 2016. Furthermore, when wind-generated electricity production were predicted to be high (in the 75th percentile) and transmission lines were congested, hydropower producers withheld 8.9% of production in relation to comparable hours under no import constraint.

Keywords: Electricity Markets, Market Power, Nord Pool, Hydropower, Wind Power, Congestion

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Contents

1 Introduction

In the Renewable Energy Directive from the European Union (2009), target shares for renewable energy (RE) of total energy consumption are established. The overarching target for the 28 EU member states collectively is set to 20 percent by 2020 and 27 percent by 2030. In addition to the overall goal, each member state is legally bound by a target RE share for 2020. In column (c) of Table 1, the targets for the Nordic countries [1] are displayed. The Nordic countries face the highest targets of all EU member states, and as seen when comparing column (b) to column (c), the targets were reached half way into the stipulated period.

Table 1: Actual (2010–2015) and target (2020–2030) shares of total renewable energy consumption (left) and as well as renewable share of electricity generation

	RE Share Energy				*RE Share Electricity*		
	(a) **2010**	(b) **2015**	(c) **2020**	(d) **2030**	(e) **2010**	(f) **2015**	(g) **2020**
Denmark	22.1%	30.8%	30%	-	22.1%	51.3%	51.9%
Sweden	47.2%	53.9%	49%	-	47.2%	65.8%	62.9%
Finland	32.4%	39.3%	38%	-	32.4%	32.5%	33%
Norway	61.1%	68.4%	67.5%	-	97.6%	106%	-
EU	12.9%	16.7%	20.0%	27.0%	28.8%	28.8%	-

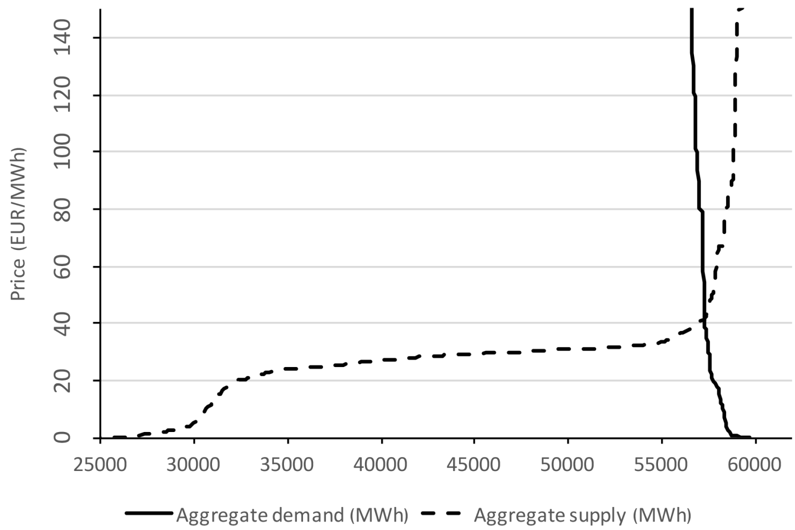
Source: Eurostat (2018); European Union (2009)

As an addition to the directive, all member states were obliged to submit to the European Commission their national action plans describing how the country intend to reach its targets. Each plan is, among other things, required to treat the subject of electricity generation and each country is obliged to set targets for how large share of the electricity generation will be generated from renewable sources. Nations in the northern part of Europe have chosen and continue to choose wind generated electricity as the main mean of production when expanding RE generation capacity. The intermittent nature of wind, where ability to generate electricity is highly correlated with the speed of wind, creates stress on the transmission system in the common Nordic market. The stress appears when large loads of electricity need to be transmitted to and from the regions of consumption and production at different points in time. This thesis concerns the competitive effects of having a large share intermittent production in an electricity market otherwise dominated by hydropower generation.

[1] Norway has agreed to report targets and values, even though they are not legally bound to do so, as they are outside the union

In the common Nordic electricity market —Nord Pool— a Walrasian auction is used to set a common price for electricity so that it matches total supply with total demand. In other words, price will be cleared where the aggregate supply curve intersects the aggregate demand curve. Wind power, characterised by intermittency and low marginal costs, will enter the auction at the very beginning of the aggregate supply curve in Figure 1, causing supply to shift out and prices to clear at a lower level. Due to convexity of the inverse demand curve, prices generally also clear on a more price-elastic part of demand, reducing incentives for dominant agents to exercise market power[2].

Figure 1: Aggregate supply and demand curves for the Nordic wholesale electricity market in a random hour of January 2017



Source: Author's rendering of Nord Pool data[3]

At times, when wind production is at high levels, the transmission system cannot facilitate the large flows needed to clear the market at a single price. When this happens, the market is split up into different price areas, and the separate price will be cleared based on the supply and demand in each zone. When transmission constraints are binding, transmission lines are physically congested and two negative effects on competition go into effect. First, as will be shown in Subsection 5.2, the demand of each new market will be less elastic, increasing the profits of withholding production. Second, each of the markets will have a reduced number of competitors to compete for the remaining demand. Large regional producers enjoy increased market shares and face larger residual demands[4].

[2]In a Cournot setting with a higher price elasticity of demand, a reduction of output will not result in as large mark-ups as it would in a scenario with a less elastic demand

[3]Data is available to students and researchers from Nord Pool's ftp server. The data can also be viewed and retrieved from https://www.nordpoolgroup.com/historical-market-data/

[4]Residual demand is the demand that cannot be served by any other producer. A producer acting strategically, may act as a monopolist on residual demand.

Large *hydropower* producers, with their unique ability to store water and defer electricity production, may take advantage of constrained periods to exercise market power. By withholding capacity in inelastic periods and shifting relatively more production to periods of elastic demand, a producer may benefit from steep price increases that would not have been possible in a regulated or fully competitive state. This thesis will estimate to what extent, if any, hydropower producers in Sweden withhold production in periods where wind power imports are constrained by insufficient transmission capacity.

The thesis concerns the day-ahead market of Nord Pool —Elspot— which is the largest and most important of the markets in the Nordic region. Elspot is cleared the day before actual production, thus a precondition for strategic conduct in hours of imports constraints, is that the agent submitting a bid to the auction can predict congested hours. In the empirical estimations, I will use wind power prognosis in an exporting zone as an instrument for import constraints. This is done to single out the effect of predictable hours of congestion. We will focus on Swedish hydropower production and its interaction with Danish wind power. To distinguish behavior of the dominant producer from total production, we use data from ENTSO-E's[5] transparancy platform. The data has, to my knowledge, never been used in published research.

The empirical results suggest that the dominant hydropower producer withheld production under hours of binding import constraints during 2015 and 2016, while other producers increased production. The dominant producer generate significantly less than other hydropower producers. Under perfect competition, producers' output should be a function of price alone. In my specification, a negative coefficient on import constraints during congested hours would suggest that producers defer from their regular strategy in relation to price, and withhold capacity. The negative coefficient we get is not significant at a 5% level, implying that the results may not be valid outside the sample period.

The issue that this thesis raises may be applicable to other regions of the world. All member nations of the European Union are currently expanding their share of renewable energy production. Most countries focus on intermittent sources such as wind or solar power. A specific example is Germany, who is expanding its electricity production capacity primarily by installing wind capacity in the northern parts of the country, while most demand is in the southern part of Germany. Adding this to the discontinuation of nuclear power production, Germany will face similar concerns to those of the Nordic market today (Kunz, 2013). Today, much of the Central European erratic wind production is balanced by thermal power, but hydropower is expanded in the Alps, for instance Austria and Switzerland, with increasing

[5]The European Network of Transmission System Operators for Electricity

capacity to balance intermittency (Björnsen Gurung et al., 2016). The idea to balance intermittent energy with hydropower is also present in many other places of the world, such as Canada, USA and New Zealand (Denault et al., 2009; Bélanger and Gagnon, 2002; Borenstein et al., 2002; Førsund, 2013; Renwick et al., 2010).

The remainder of this thesis is structured as follows. In Section 2, I present the research question, Section 3 reviews related literature. Section 4 explains institutional background of the Nordic electricity market. In Section 5, I show that profit maximizing firms with market power withhold production in price inelastic periods and shift production to relatively more price elastic periods. Section 6 describes the identification strategy, Section 7 and Section 8 present and discuss the results, and Section 9 concludes.

2 Research Question

In Subsection 5.3, I show that hydropower producers with market power maximize profits by shifting production to time periods with relatively inelastic demand, and produce more when demand is relatively more elastic. I also argue that for firms to exercise market power, they must predict the hours of congestion at the time of the quantity allocating auction the day before actual production. Thus, the question I seek to answer in the empirical sections is:

Do Swedish hydropower producers exercise market power by predicting Danish wind-generated import constraints and allocating less production to these —relatively price-inelastic— periods?

I study two separate cases. First, I look at the overall shifts of production for all hydropower producers in the industry. Second, I use a data set of production from the dominant agent on the Swedish market, Vattenfall, and compare it to the production of other hydropower companies in the market. We will refer to the other companies as the fringe producers.

3 Related Literature

3.1 Overall Market Power on the Nordic Electricity Market

Fridolfsson and Tangerås (2009) surveyed the current position of the research on market power in the Nordic electricity market. They found no evidence of abuse of market power in the traditional "blatant" sense, wherein one considers market power exercised through a markup of prices on the marginal units. Furthermore, they argue that concentration ratios of producers on the Nordic market are relatively small when transmission is unconstrained, but acknowledge that congestion may "have important anti-competitive effects".

Damsgaard et al. (2007) studied all countries that were part of Nord Pool at the time in a two-part study. Part I concluded that there were strong potential for market power in the Nordic region, part II concluded that their empirical findings could not prove any exercise of such market power.

In a working paper, Lundin and Tangerås (2017) characterizes the Nordic wholesale electricity market as Cournot type market where firms compete in quantities in the base load. They establish that market power among the large firms accounts for markups of 8–11% on average. It is likely that this markup is not constant over time, but varies and is lower at certain times and considerably higher at other times, when anti-competitive behavior is made possible. Furthermore, the authors find a positive relationship of exercise of market power and the introduction of bidding areas into separate zones.

In terms of overall market power in the Nordics, there is no clear consensus. Vassilopoulos (2003) and Hjalmarsson (2000) could not reject a hypothesis of perfect competition in a Bresnahan (1982); Lau (1982) framework, while Bask et al. (2011) found a significant markup over marginal cost over an extended period of time (from 1996–2004) that decreased with the expansion of Nord Pool to include Denmark and Finland.

3.2 Transmission Constraints

Much empirical research has been dedicated to measuring anti-competitive effects of binding transmission constraints. Notable recent contributions are Ryan (2017) who studied the Indian electricity market and Wolak (2015) who studied the case of Alberta. Both found strong competitive effects of increasing transmission lines to counter congestion effects. In the Nordic region, most studies relating to market power and transmission constraints have focused on southern Norway. Steen (2003) used a dynamic Bresnahan and Lau setup and found that hydropower producers in the southern Norwegian region exercised market power with a small but significant markup during the 12.5% of hours in the sample where bottlenecks were congested. This is in line with the results of Johnsen et al. (1999), who found a 15% increase in price in the southernmost price area in Norway during congested hours. Unlike this thesis, the studies of Steen and Johnsen et al. did not discuss predictability or cause of congestion, but treated all congested hours the same. My thesis argues that market power due to congestion can only be exercised on elspot if congestion is predicted the day before, and particularily studies the import constraints caused by wind power, as wind power is positive for congestion and also predictable through hourly production prognoses.

Mirza and Bergland (2012) studied the effect of binding import constraints in southern Norway, and found limited but significant market power if congestion appeared at some predictable hours. The markups were small, never exceeding 1%. In a followup study, Mirza and Bergland (2015) argued that market power may become larger if hydro-producers themselves could induce congestion through withholding strategies. They found evidence suggesting that markups were on average 19.5% above competitive levels during the import constrained hours induced by hydroproducers.

3.3 Intermittent Production and Congestion

Most research concerning the interaction between intermittent renewable energy production and congestion have been theoretical modelling. Kunz (2013) modeled the future of the German electricity market and argued that increasing share of wind production causes stress on the system with increased need for congestion management. Mauritzen (2013) analyzed the flows that result as a consequence of intermittent wind power in Denmark, and found that much of the intermittent power in Denmark was exported to Sweden and Norway, rather than lowering the thermal power output in Denmark. Consequently, there exists an increased risk of congestion when wind is strong.

Bigerna et al. (2016) studied market power in relation to development of intermittent wind and solar expansion in Italy. They found that renewable energy production reduced the general market power in the Italian market. They also found that the intermittency of renewable production is the main source of congestion between price areas in Italy. When transmission constraints became binding, they found that market power of the dominant agent (and some other large producers) increased. My thesis differ from the paper of Bigerna et al., primarily in two aspects. First, in Italy, the dominant players are mainly producers of thermal electricity from gas and coal, so they do not have to take the dynamic aspects, that a hydroproducer faces, into consideration. Second, in Italy, detailed data on zonal and company level is available for research. So I have to rely on less direct measures of market power.

4 The Nordic Electricity Market

4.1 Deregulation and Integration of National Electricity Markets

In January 1, 1991, the Norwegian Energy Act (Ministry of Petrolium and Energy) went into force, liberalizing the previously regulated Norwegian electricity market. The objectives were among others to make the market more efficient and to smooth out consumer prices between different geographical areas of Norway. Shortly after the Norwegian deregulation, the Swedish government decided to reform the country's electricity market, with the objective of increasing efficiency and reduce prices. Andersson and Bergman (1995) raised concerns that market power as a result of high concentration would become very high in Sweden, with a CR1[6] on the seller side of 0.5. They argued that deregulation without further measures would not reduce, but instead likely increase equilibrium prices. Andersson and Bergman suggested that the large and dominant state owned electricity producer, Vattenfall, should be split into at least two smaller entities. The governments of the Nordic countries instead decided to integrate the national markets of the Nordic countries to dilute the concentration within the countries —especially Sweden (Amundsen and Bergman, 2002). In 1996, Sweden and Norway integrated their markets and a common clearing house was established, Nord Pool. Finland joined the common spot market in 1998 and Denmark followed in 2000. In the period from 2010 to 2013, Estonia, Latvia and Lithuania were included in the spot market.

Figure 2: Blue and red dotted lines show demand in two separate geographical areas. Black line shows the two markets combined. Aggregating demand in two geographical markets increases price elasticity of demand.

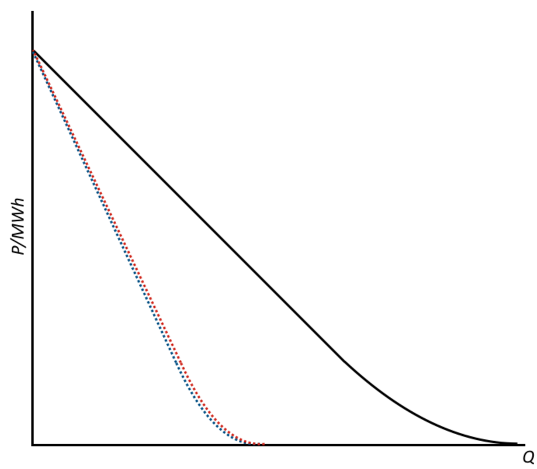


Figure 2 illustrates the idea behind integrating the Nordic electricity markets. When two geographic regions, each with dominant producers, are connected, there are two main effects.

[6]Concentration ratio measured as market share of the largest seller.

First, they go from two markets with relatively inelastic demand, to becoming a single market with relatively more elastic demand. Second, the concentration ratio is diluted, with the formerly dominant producers now competing for total demand. When transmission between the two regions are congested, the reverse scenario takes place.

4.2 Pricing Mechanism

Nord Pool acts as the common clearing and trading house of the electricity wholesale markets of the Nordic countries. It is not mandatory for a producer to trade on Nord Pool. Even so, approximately 77% of consumed electrical power in the Nordic countries pass through their system (Tangerås and Mauritzen, 2018). The remaining 23% consists of direct trade, either bilateral or between a producer and major customers. The largest and most important market of Nord Pool is Nord Pool Elspot, which is a day-ahead market in which hourly prices are cleared the day before the actual trade. Elspot handles 99% of all traded volume on the Nordpool markets. The remaining 1% is traded on Elbas, which is a real time market. Contracts and derivatives are almost exclusively set with reference to the Nord Pool Elspot system price. Because of limited capacity in the transmission system, separate bidding areas have been defined according to Figure 3. The borders of the bidding areas have been drawn where transmission capacity is particularly low. Because of the limited transmission capacity, the transmission lines between price areas are often referred to as "bottlenecks".

Figure 3: The map shows the pre-defined price areas of the Nordic and Baltic region. Most of the time, several or all price areas constitute a price zone. Source: Nord Pool

To account for transmission incapacity over bottlenecks, the pricing mechanism used by Nord Pool Elspot is a Walrasian double auction setup, adjusted according to a zonal pricing system. The clearing mechanism in the zonal system works as follows (Bjørndal and Jörnsten, 2007):

1. At day d each producer who wants to sell electrical power into the spot market submits sell orders (bids) for the 24 operating hours starting at hour 1 of day $d+1$. Each order consists of a step wise non-decreasing curve in which the producer specifies the price at which she is willing to sell the electricity, and the volume she is willing to sell at that price. Simultaneously, each retailer, trader or other customer places buy orders in a step-wise non-increasing curve specifying the volume she is willing to buy at any given price.

2. Nord Pool aggregates all submitted buy and sell orders and clears the market (recall Figure 1 for an example) at the equilibrium which becomes the Elspot system price. The price is cleared absent transmission constraints.

3. Since the producers with the lowest bids should serve demand, wherever it arises, electrical flows are induced on the transmission system. If flows resulting from the cleared system price are larger than the capacity of the grid, the Nordic region is split into two or more zones according to pre-defined price areas and congested bottle necks.

4. Nord Pool then reduces the net transmission such that all transmission is within the transmission lines' physical bounds.

5. Each newly formed zonal area is cleared separately. Creating different prices for separate zones. The price will always be higher in the import constrained zone and a lower in the export constrained zone.

6. If again, resulting flows induce congestion within the smaller zones. The zone is split up into even smaller zones, and prices are cleared for each of these zones separately. At most, Nord Pool Elspot can assign different prices to the 15 pre-defined price areas[7] (see Figure 3).

7. All sellers and buyers in a zone are paid according to the zonal price in which they produce or consume electrical power.

4.3 Ownership Structure of Swedish Electricity Production

Electricity production in Sweden —and in particular hydropower production— is dominated by the state-owned entity Vattenfall AB. The ownership structure of installed capacity in Sweden is displayed in Table 2. Vattenfall controls 7917 MW out of the total 16181 MW,

[7] Prices in the Baltic countries are always cleared separately

summing up to 49% of market capacity. Vattenfall is also the largest owner of nuclear capacity in Sweden. In terms of total installed capacity, Vattenfall owns 14098 MW, approximately 2.4 times the capacity of the second largest producer, and a total of 35.2% of installed capacity. Other notable agents on the Swedish market is Finish state-controlled producer Fortum, German Uniper (formerly E.ON) and Norwegian state-controlled Statkraft. In "remaining", all capacity owned by minor producers is aggregated. Much of the remaining hydro capacity is owned by private corporations, such as paper mills and manufacturing companies in other energy intense industries. A large part of the Thermal energy listed as remaining is reserve capacity plants owned by Svenska Kraftnät —the Swedish transmission system operator (TSO)— and is used to balance the system when needed. Most of the electricity generated by the manufacturing industry is consumed internally and is never traded on Nord Pool.

Table 2: Swedish installed capacity in MW by producer and technology by the end of 2016

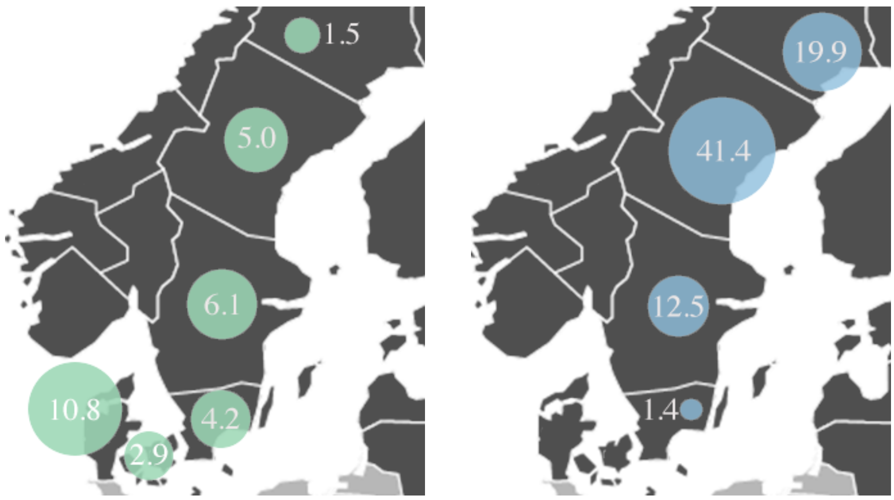
Producer	Hydro	Nuclear	Wind	Thermal	Solar	Sum
Vattenfall AB	7917	4954	303	924	0	14098
Fortum Power and Heat AB	3063	1553	42	10	0	4668
Sydkraft AB (Uniper)	1794	2464	0	1647	0	5905
Statkraft Sverige AB	1262	0	334	1	0	1597
Skellefteå Kraft AB	655	64	272	54	0	1045
Remaining	1490	41	5569	5406	185	12691
Total Swedish Capacity	16181	9076	6520	8042	185	40004

Source: Energiföretagen Sverige (2017)

It is worth stressing that the numbers presented in Table 2 are not actual output, but installed capacity. In terms of actual output, only nuclear produces close to maximum capacity. Over the course of a year, hydropower production depends on the precipitation that year, and usually reaches the same production levels as nuclear. Wind power is produced according to wind, and reaches approximately 10% of total Swedish production over the course of a year. Most of the thermal power is reserve capacity, and is usually not active. In terms of actual generation during 2016, Vattenfall accounted for 42% of total Swedish production and 17% of total Nordic production (Energiföretagen Sverige, 2017).

Since the research question focuses on the interaction between Danish intermittent wind power production and Swedish hydropower conduct, it is important to understand the geographical location of production facilities. In Figure 4, we see the location of wind- and hydropower production in Sweden and Denmark. With eight of Sweden's ten largest cities, SE3 is the price area in Nord Pool that has the highest demand for electricity. With a small per capita production, the area needs to be served by imports from other price areas. Traditionally, this demand has been served by hydropower production in SE1 and SE2, the northernmost regions of Sweden. The growing wind power capacity in Denmark, has during later years, developed to become another source of electricity for SE3. By nature, wind power is intermittent, and produces at full capacity in certain hours, and close to zero capacity in other hours. When wind supply is high, a downward pressure on price makes prices clear lower than average. Figure 4a shows that western Denmark, DK1, is the largest producer of wind-generated electricity in the region. With a population of 2.5 million in DK1, most wind power during hours of high production must be exported to high demand areas, such as SE3. When wind power in Denmark produces at high levels, transmission lines to neighbouring areas often get congested, putting a cap on the competitive effect of increased wind power in the system.

Figure 4: Location and output of wind- and hydropower generation in Denmark and Sweden during 2016. Figures in TWh. Data source: ENTSO-E (2018)



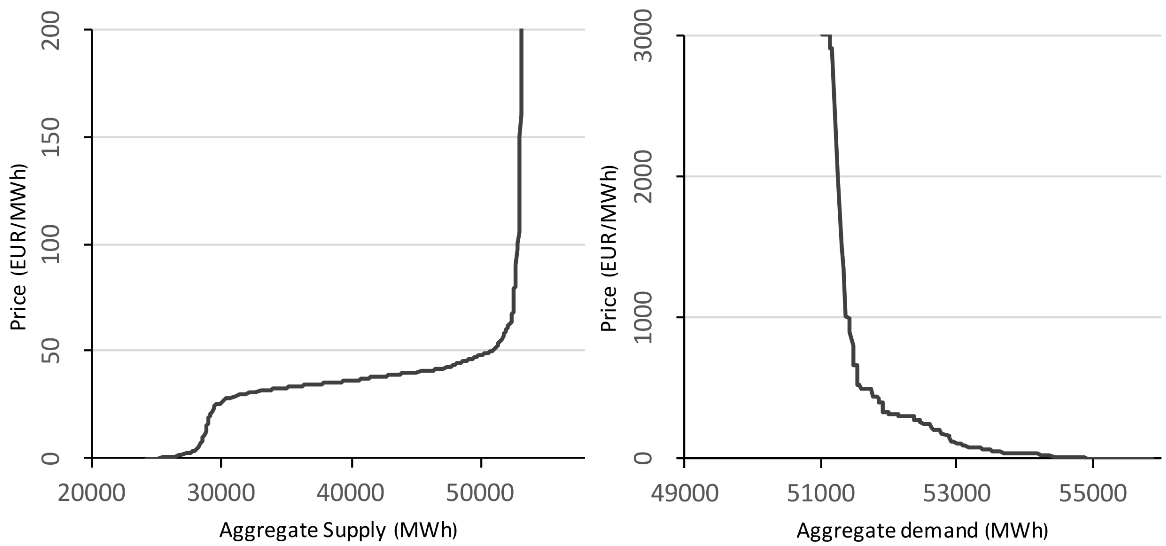
(a) Wind power output *(b) Hydropower output*

4.4 Stylized Supply and Demand

Denmark produces more than 50% of its annual electricity demand using wind turbines (Eurostat, 2018), the remaining demand is mainly produced by coal- and gas-powered thermal power plants (ENTSO-E, 2018). This mix places Danish power production in the higher and the lower ends of the marginal cost spectrum. In Figure 5, showing a typical shape of the aggregate supply and demand bid curves on Nord Pool, Danish wind production is to the very left with bids just below zero. Producers bid below zero when there is a cost affiliated with not producing. For wind generating companies there is a cost associated with braking the turbines. Thus, wind farms produce as long as the electricity price is greater than the cost of throttling production.

In the hour represented in Figure 5, we see that supply bids for approximately 25000 MWh are submitted at a negative range[8]. The negative bids consist of wind power as well as Swedish and Finish nuclear. Nuclear producers face marginal costs correlated to the prices of uranium and plutonium. Because of high start/stop costs of nuclear generators, however, producers will act as price takers, and bid negative prices to ensure even production levels at all times[9]. Hydropower bids typically are submitted close to zero, but occasionally becomes higher when water reservoirs are low, as the opportunity cost of forgone production at a later state may become quite severe. The rightmost convex part of the aggregate supply curve consists of thermal power (waste, biofuel, coal, oil, gas and peat), where marginal cost is highly correlated with the cost of fuel. Most of the thermal capacity is supplied from Finland and Denmark. It is rare that the full Nordic demand is served by, hydro, nuclear and wind (Energiföretagen Sverige, 2017). Therefore, aggregate demand with very few exceptions intersects supply at this convex part of the curve. In the end, the supply curve leads almost vertically to the 3000 EUR/MWh price cap.

Figure 5: Characteristic shape of aggregate supply and demand bids submitted to Nord Pool. Example from November 8, 2016.



Source: Author's rendering of Nord Pool data

The right graph in Figure 5 depicts the typical shape of the Nordic aggregate demand. For this particular hour approximately 51000 MWh is demanded very inelastically in the short run, even if price would clear at market cap of 3000 EUR/MWh. At lower prices, the curve is convex, and price elasticity of demand increases.

[8]Supply and demand curves shift by the hour. The graph illustrates the typical shape and curvature of supply and demand, and particular numbers should not be taken as typical

[9]With the current market design, system prices have never cleared at a negative value. On occasion, zonal prices clear below zero, and producers pay retailers to accept electricity

5 Theory

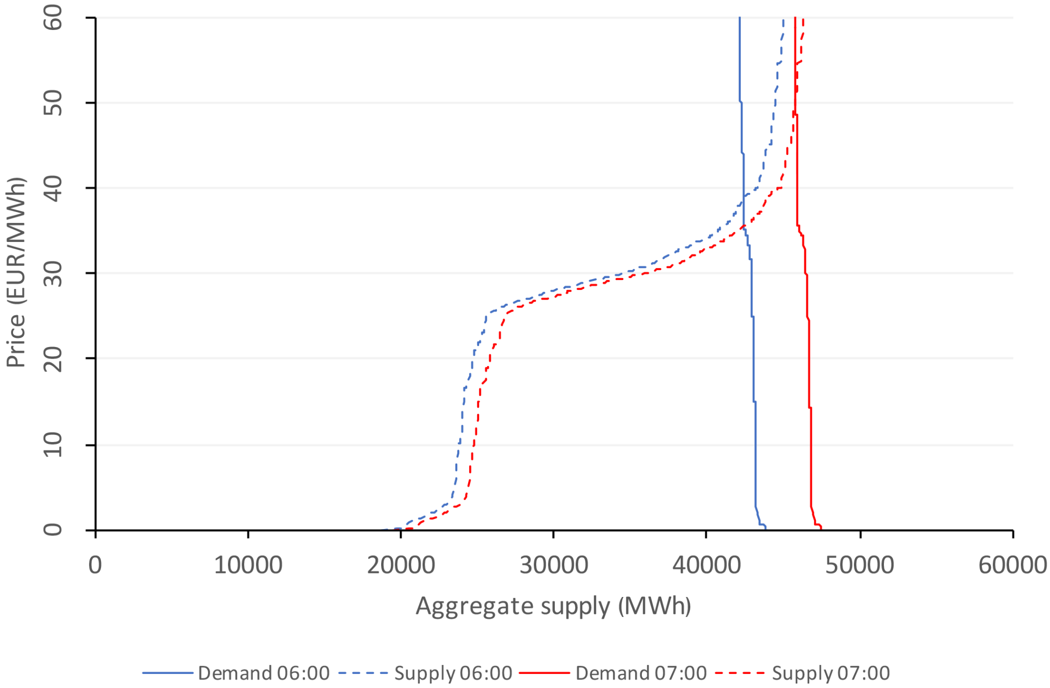
5.1 Market Power in the Nordic Electricity Market

The problem with any static model of market power, such as the general Bertrand, Cournot or Bresnahan (1982) and Lau (1982), in a market dominated by hydropower producers, is that firms must solve a dynamic maximization problem (Førsund, 2013). In this thesis, we apply a model where firms compete in quantities, but where the individual firm takes a dynamic approach to profit maximization, a similar approach is used by Mirza and Bergland (2015). In the long run, a hydropower producer is constrained by the output capacity of its generators and the inflow to its reservoir, and does not decide how much to produce. In the medium and short run, however, the producers can choose to allocate production over time so that they increase quantity when prices are expected to be high and reduce the quantity when prices are expected to be low.

As discussed in Section 3, there is not much literature that suggests existense of any significant market power at the marginal unit, as estimated by price markups over marginal cost. Furthermore, nuclear and wind power producers have very limited possibility to act strategically in the short run due to intermittency of wind and high startup costs for nuclear. Hydropower producers, through their ability to shift production to different points in time (within reservoir capacities), have large possibilities to act strategically in the short run. One way in which hydropower producers may exercise market power is to spill water, i.e. releasing water from the reservoir without running it through the turbines. With lower storage levels in the reservoir, scarcity of water puts an upward pressure on price. Such behavior is not observed on the Swedish market and could easily be detected (Johnsen, 2001). A more subtle way of exercising market power for a hydro power producer is to allocate production to periods in ways that are not optimal to society. In Subsection 5.3 we illustrate how allocations that hurt society may be profit maximizing to hydroproducers with market power.

A trait of the elctricity market is that demand is very inelastic at times. Thus, small shifts in supply or demand can have very large effects on price. Figure 6 Shows the price of two consecutive hours of October 13, 2016. At 6:00 am, the system price was cleared below 40 EUR/MWh. One hour later, a shift shift of the demand curve, and a smaller shift of the supply curve, increases prices by more than 30 percent to around 50 EUR/MWh. Note that the entire (visible) supply curve shifts out, meaning that the quantity adjustment in supply bids is done by producers with low marginal cost, such as wind or hydro.

Figure 6: Aggregate demand and supply curves for two consecutive hours in October 13, 2016



Source: Author's rendering of Nord Pool data

5.2 Effects of Binding Transmission Constraints

In this section, I illustrate that when markets are constrained in imports, and the constraints become binding, the residual inverse demand of electricity in the import constrained area becomes steeper —less elastic. I further show that a profit maximizing hydropower producer with market power will shift water to produce more than the competitive equilibrium in periods with relatively more price-elastic demand, and withhold production in periods where price elasticity is low.

Any model considering the behavior of hydropower producers must take into account the intertemporal maximization problem. In the long run, hydropower producers do not choose how much to produce. When reservoirs are full, hydro plants will generate at least ”run of the river” volumes. When reservoirs are empty, hydro plants can produce a maximum of ”run of the river” volumes. The amount of water in the reservoir decides the flexibility a hydro producer has in terms of withholding or increasing volumes. Furthermore, if a hydro producer withholds production today, she must produce more in the future and vice versa. Hence, the maximization problem of a producer is of a dynamic nature.

Borenstein et al. (2000) show that bottlenecks between two geographical areas may hamper competition if both sides are dominated by a single player. Their model is shown for the symmetric case with fossil fueled thermal power as the source of electricity production. In such a case, there will be a strategic interaction between the players in the two connected zones. Depending on the capacity of the transmission line, the strategic game may lead to duopolistic Cournot equilibrium, an equilibrium where the agents act as monopolists on their residual demand, or no equilibrium at all. In our case, as we are looking at two zones where one is dominated by wind (intermittently), and the other is dominated by hydropower and nuclear. Our setting will become rather different. Due to the low marginal cost of generating electricity with wind power, and since the energy source, wind, cannot be stored and used at a later time, we may consider the wind power producers to be without a strategic choice of action. In other words, electricity will be produced in the wind farms as long as there is wind. On the Swedish side, nuclear, will always produce, since costs of changing output capacity is high. Thus, nuclear power plants have no short-term strategic decision.[10] Short term strategic behavior in the Nordic electricity market is a privilege of hydropower producers, who can alter production volumes costlessly and instantaneously.

We consider two regional markets, Sweden (se) and Denmark (dk), where Swedish production is dominated by a hydropower producer and a competitive fringe. Between the two regions there is a transmission line of capacity k. The transmission line connects the two markets and works to arbitrage out price differences. Similar to Borenstein et al. (2000), I derive the case where the two markets are symmetric in demand. If there were no connection between the two regions, the Swedish hydro producer would act as a monopolist on its residual demand. With the transmission line, however, the two markets are coupled, so that the hydro producer can compete to serve Danish demand, and Danish producers can compete to serve Swedish demand. I denote residual demand in Sweden as Q^{se}, quantity supplied by the dominant Swedish supplier by q^{se} and quantity supplied by the Danish producers q^{dk}. We write the residual demand of the dominant Swedish producer:

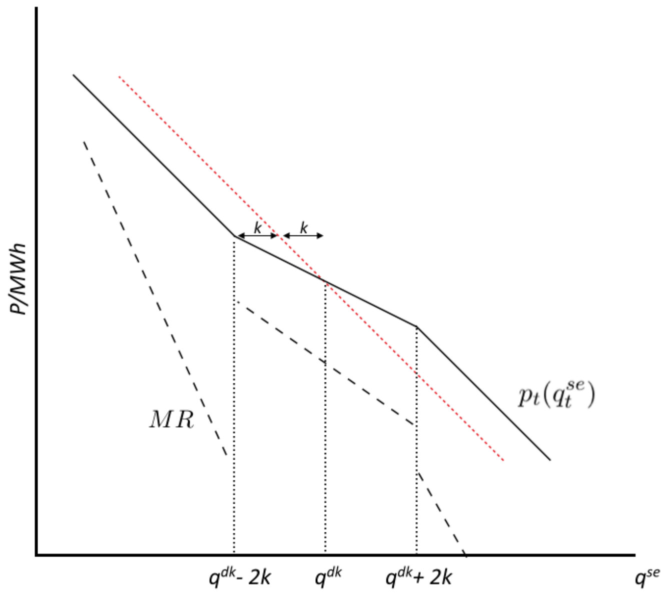
$$Q^{se} = \begin{cases} q^{se} - k & if \quad q^{se} > q^{dk} + 2k \\ \frac{1}{2}(q^{se} + q^{dk}) & if \quad q^{dk} - 2k < q^{se} < q^{dk} + 2k \\ q^{se} + k & if \quad q^{se} < q^{dk} + 2k \end{cases} \tag{1}$$

We illustrate the residual demand faced by the dominant Swedish producer in Figure 7. The graph should be read in relative terms. If producers in each market produces according to the demand of that region, there will be no flow in either direction and prices will be the same in

[10]Nuclear producers likely enjoy long term market power, where they can act strategically in scheduling maintenance breaks etcetera. This is not applicable within the day, and cannot happen as a response to sudden changes in demand or elasticities. For market power exercised by nuclear producers, see for instance Lundin (2016)

both regions. If in any period, the Nord Pool auction clears so that producers in one country produce more than that country's demand, and producers in the other one less, electricity will flow from the country that produces more, to the one that produces relatively less. Now, when wind blows, it often happens that the Nord Pool auction assigns Danish wind power to produce very high volumes. In Figure 7, then, q^{se} becomes lower than $q^{dk} - 2k$. The dominant hydropower producer will find himself a monopolist on the residual demand, the demand left of $q^{dk} - 2k$ in the figure. This part of demand, where markets are not joined, has a steeper slope corresponding to a less elastic demand. The red dotted line in the figure shows the demand facing the dominant player had the markets not been connected. A transmission line shifts the residual demand left and right by the capacity of the transmission line. The flacker part of the curve is the aggregated demand of the two markets less Danish producers' quantities (q^{dk} in Figure 7).

Figure 7: Inverse residual demand curve for a dominant player in the Swedish market



A dominant producer in a market with a competitive fringe, will maximize profits by producing until marginal cost equals marginal revenue. In a market where thermal power dominates, such as the one modeled in Borenstein et al. (2000), maximizing total profits means maximizing profits in every time period. Furtermore, two thermal power markets connected will face a strategic game and produce according to their best response function. The strategic decision that a hydropower producer, connected to a market with predominantly wind power, is quite different. Since there is no strategic decision in terms of how much to produce in any period for wind producers, and due to the intermittent nature of wind, q^{dk} in Figure 7 change dramatically from hour to hour. This means that the Swedish hydropower producer from time to time will face a demand corresponding to the import constrained (left) part of the graph. Often, the transmission line will not be congested, however, and the Swedish dominant faces the middle part of the graph. Sometimes, although not as often, wind production is very low in Denmark and the transmission line for Swedish producers becomes export constrained. I do not focus on the export constrained case in this thesis.

5.3 Profit Maximizing Firms

The profit maximizing decision for the dominant hydropower producer is of a dynamic nature. Since the producer can —within certain constraints— choose when to produce electricity, but not how much to produce in total, she will want to produce when prices are high, and save water when prices are low. For a hydropower producer with a dominant position, the decision will differ from a producer in the competitive fringe or the decision of a social planner. Førsund (2013) shows that for a dominant hydropower producer, it is profit maximizing to shift demand to periods of relatively more elastic demand, and consequently hold back production in periods of relatively more inelastic demand. We consider the intertemporal maximization problem facing a hydropower producer:

$$\max_{q} \sum_{t=1}^{T} \left(p_t(q_t^{se}) q_t^{se} - c_t q_t^{se} \right) \tag{2}$$

Subject to

$$R_t \leq R_{t-1} + I_t - q_t^{se} \tag{3a}$$

$$R_t \leq R^c \tag{3b}$$

$$R_t \geq 0 \tag{3c}$$

$$q_t^{se} > 0 \tag{3d}$$

Where $p_t(q_t^{se})$ is the inverse demand curve illustrated in Figure 7, q_t^{se} is the quantity produced by the dominant hydropower producer in Sweden. c_t is the marginal cost of a hydropower producer. Assuming that the marginal operable cost of producing electricity is zero, we can neglect this term. R_t is the level of water in the reservoir at the end of time t. I_t represents the inflow to the reservoir during time-period t, R^c is the total capacity of the reservoir. Equation 3a is the law of motion for the reservoir level —the reservoir level at the end of period t will be the reservoir level at the end of the previous period, *plus* the inflow of water to the reservoir during the period, *less* the water used for production in the period. The reason we do not assume equality in Equation 3a, is that the hydro producer has a possibility to spill water without producing electricity. Equation 3b says that in no period, the producer can store more water than the full capacity of the reservoir. Equation 3c says that reservoir level must be non-negative in every period, and Equation 3d assumes production in every period.

To maximize Equation 2 subject to the constraints, we construct the Lagrangian.

$$\mathscr{L} = \sum_{t=1}^{T} p_t(q_t^{se})q_t^{se} - \sum_{t=1}^{T} \lambda_t \left(R_t - R_{t-1} - I_t + q_t^{se}\right) - \sum_{t=1}^{T} \gamma_t \left(R_t - R^c\right) \tag{4}$$

The producer chooses quantity to produce in period t and reservoir level at the end of period t. The first order conditions and complementary slackness conditions are:

$$\frac{\partial \mathscr{L}}{\partial q_t^{se}} = \frac{\partial p_t(q_t^{se})}{\partial q_t^{se}} q_t^{se} + p_t(q_t^{se}) - \lambda_t = 0 \tag{5a}$$

$$\frac{\partial \mathscr{L}}{\partial R_t} = -\lambda_t + \lambda_{t+1} - \gamma_t \leq 0 \tag{5b}$$

$$\lambda_t \geq 0 \tag{5c}$$

$$\gamma_t \geq 0 \tag{5d}$$

Define the inverse elasticity of demand, $\tilde{\eta}_t \equiv \dfrac{\partial p_t(q_t^{se})}{\partial q_t^{se}} \dfrac{q_t^{se}}{p_t(q_t^{se})}$, related to the slope of demand in Figure 7. We can rewrite the first order condition in Equation 5a:

$$\frac{p_t(q_t^{se})}{p_t(q_t^{se})} \frac{\partial p_t(q_t^{se})}{\partial q_t^{se}} q_t^{se} + p_t(q_t^{se}) - \lambda_t = 0$$

$$p_t(q_t^{se})\tilde{\eta}_t + p_t(q_t^{se}) - \lambda_t = 0$$

$$p_t(q_t^{se})(1 + \tilde{\eta}_t) = \lambda_t \tag{6}$$

Note that the left-hand side of Equation 6 is the price function adjusted to twice the slope of the inverse demand function and equals marginal revenue. The right hand side, is the shadow price of the water. A profit maximizing firm with monopoly power will produce until marginal revenue equals the shadow price of water. γ_t is the shadow price of reservoir capacity. It may be interpreted as the gain in profit from increasing the maximum reservoir capacity an infinitesimal amount. At all times when Equation 3b is not binding, γ_t will be zero —if the capacity constraint is not binding, increasing maximum capacity will not change the decision of the producer, nor affect profits. Similarly, if Equation 3c is not binding, Equation 5b will hold will equality. If the capacity constraints are not binding in any period, then it follows from Equation 5b that λ_t must equal λ_{t+1} In Figure 8, the case of a two period terminal system, where capacity constraints do not bind, is illustrated.[11]

Figure 8: Two period maximization for a monopolist on residual demand with different elasticity of demand in the two periods

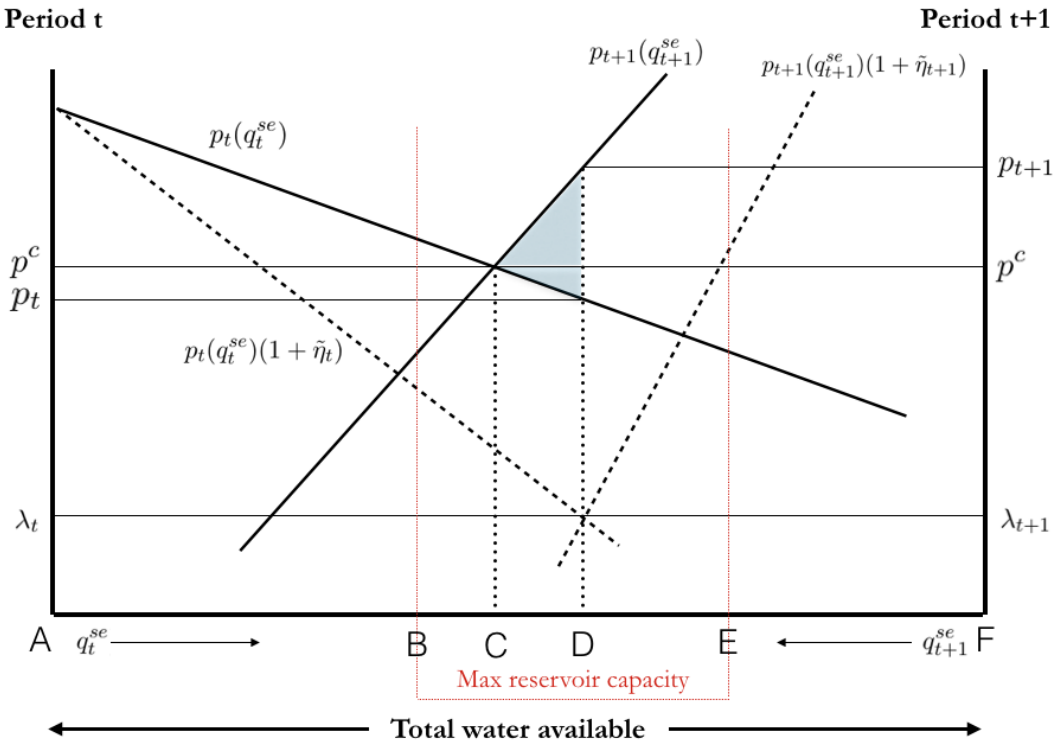


Figure 8 serves to illustrate the case of the dominant Swedish hydropower producer. In period t, the transmission line between DK1 and SE3 is not congested, and the demand facing the Swedish hydropower producer is relatively elastic. In period $t+1$, high wind production induces congestion on the connection between the countries. In this period the demand facing the Swedish producer will correspond to the leftmost part of Figure 7, with a relatively steeper slope and consequently less elastic demand. The total water available —measured in a unit of the electricity that the water could generate— over the two periods is quantity A to F on the horizontal axis. Quantity produced in the first period is measured from A and to the right on the horizontal axis, quantity produced in the second period is measured from F and to the left on the horizontal axis. The left-hand vertical axis indicates prices in the first period, the right-hand vertical axis indicates prices in the second period. Water available for production in the first period, will be A to E —this quantity consists of water stored from previous period, R_{t-1}, and inflow during period t. Quantity B to E is the capacity of

[11]For illustration of a case with binding constraints, see figure 3.4 in Førsund (2013)

the reservoir, this is the maximum amount of electricity generation, that the producer can defer to period $t + 1$. Quantity F to E is water inflow in period $t + 1$, thus A to B must be produced in the first period and F to E must be produced in the second period (unless the producer chooses to spill water).

The profit maximizing firm with zero operations related marginal cost, seeks to maximize the area under p_t and p_{t+1}. When constraints in Equation 3b and Equation 3c are not binding, $\lambda_t = \lambda_{t+1}$ and producers will produce until the elasticity adjusted demand curves of the two periods intersect. This results in an allocation of quantity A to D to the first period, and quantity F to D to the second and last period. D thus represent the cutoff point for the dominant producer and quantity D to E is stored and produced in the second period. The competitive equilibrium, or that of a social planner, would instead maximize total surplus —the area under the price function— according to:

$$\max_{q} \sum_{t=1}^{T} \int_{z=0}^{q_t^{se}} p(z)dz \tag{7}$$

Consequently, the allocation of the competitive state, denoted C, only depends on the price functions, with no adjustment depending on elasticity. The shaded area in the graph, represents a welfare loss due to market power being exercised at allocation D. The main take-away from this graph is that a dominant producer, acting as a monopolist on residual demand, will shift water to the relatively elastic period, and produce less in periods of lower elasticity (more inelastic periods). Note that this result will hold even when the social optimum becomes constrained by reservoir capacity —when B is in between C and D. When the maximization problem of the dominant producer becomes binding, i.e. when Equation 3b is binding, B will be located to the right of D, and the socially optimal solution and the dominant producers solution will be the same. The optimal solution of the dominant firm will never allocate more water to the period of less elasticity than the social planner would.

5.4 Theoretical Predictions and Assumptions

To summarize the theoretical predictions. Under the assumptions of (*i*) quantity competition, (*ii*) profit maximizing firms and (*iii*) sufficient reservoir capacity, we expect to see that hydropower producers with market power withhold production under periods of import constraints. Furthermore, wind power is relatively predictable, and also has a generally positive impact on competition (Bigerna et al., 2016). Thus, when the import constraints are predicted by the wind power prognosis, we expect to see a stronger effect than for other (predominantly demand driven) import constraints.

The three assumptions are reasonable. (i): Lundin and Tangerås (2017) argues that at least on the supply side, the Nord Pool bidding behavior follow a Cournot setting. Even if a fully homogenous good, and an auction setting where producers submit both price and quantity, are characteristics suitable for price competition modeling, capacities for each producer are constrained and not easily adjustable. At no point in time, any single producer in the Nordic electricity market can serve full demand, making price competition models (such as Bertrand) modelling insufficient for the Nordic electricity market.

(ii): Although three of the four largest electricity producers on Nord Pool are state-owned, the market has been deregulated and the entities are not tax-funded but responsible for their own revenues and profits. Furthermore, as seen in the related literature section, there are evidence suggesting that the state-owned firms do not necessarily act as social planners but rather do exercise market power to increase profits.

(iii): The large hydropower producers have large reservoirs that very seldomly reach full or empty levels. Within shorter periods of time, producers have large possibilities to shift production between hours.

6 Method

Subsection 4.2 describes the clearing algorithm of the Nordic electricity market, and consequently that price differences between zones arise if and only if there exist transmission constraints in bottlenecks between the zones. In Section 5, I argued that the Nordic electricity market is characterized by quantity competition, under which hydropower firms with market power may adjust their output levels below the competitive equilibrium, and shift production to periods with higher price elasticity of demand. If then, firms in a specific zone withhold production under times when that zone is importing, this is a sign of market power. Given this background, we consider the following model:

$$H_{zt} = \delta_0 + \alpha IC_{zt} + \beta P_{zt} + \gamma \boldsymbol{S}_{zt} + u_{zt} \tag{8}$$

H_{zt} is quantity of electricity generated by hydro water reservoir plants in zone z and hour t. As hydro reservoir plants are the only facilities where short term quantity adjustments are feasible, this is where we expect to see output alteration in case market power is exercised.

IC_{zt} is a variable representing predictable import constraints to zone z. P_{zt} is the day-ahead wholesale price of electricity in zone z at time t. In a Cournot setting, price will be a key determinant of quantity for the supplier. Other than price, quantity is also related to various supply and demand shifters, captured here by vector $\boldsymbol{S}$. We are mainly interested in estimating α, and will specify a setting for the specific case of Sweden and Denmark in Subsection 6.2.

6.1 Identifying Market Power

Green and Porter (1984) examined behavior of collusion and showed that in a dynamic market with homogeneous products, unexpected price outcomes can either depend on an unexpected shift in market demand, or agents deviating from the collusive agreement. Porter (1983) argued that when we have an indication of when firms are under a collusive state or a noncooperative state, we can introduce a binary variable indicating a switch between the two regimes (collusive and noncooperative), to rule out shifts in price as a function of demand shifts, and identified a difference in markups between the collusive periods and the noncooperative. In this thesis, the idea of Porter is used to identify changes in market power between periods of no or unpredictable constraints, and periods of predictable constraints. As argued in Subsection 5.3, and as originally shown by Joskow and Tirole (2000), firms with some market power, will enjoy larger market power when imports are constrained and produce a lower quantity than under perfect competition. Under the assumption of perfect competition in the periods in which no constraints bind, we can interpret the outcome under binding import constraints as the difference in output from that of a competitive outcome. If, however, we do not have a competitive state under the periods in which constraints do not bind, as suggested by Lundin and Tangerås (2017), the analysis still holds, but our estimated effects will be in relation to the average market power exercised in the market. See Mirza and Bergland (2015) for a similar approach to identify market power in self-induced import constrained areas in Southern Norway.

6.2 Empirical Strategy

I specify a model to be estimated, where I specifically look at the zone including price area SE3. Using a log-log specification for comparability and dropping the z subscript, I consider the following specification for estimating the potential anti-competitive effect of import constraints:

$$lnH_t^{se} = \delta_{0A} + \alpha_A IC_t^{dk1} + \beta_A ln(P_t^{se}) + \gamma_A \boldsymbol{S}_t + \varphi_A FE_t + \varepsilon_t \tag{9}$$

H_t^{se} is a measure of the total quantity of hydropower produced in SE1, SE2 and SE3. Most of the time, SE1, SE2 and SE3 are in the same zone —there are no transmission constraints between the three areas. Therefore, a reduction in output in SE1 or SE2 has the same effect as a reduction in SE3. SE4 has negligible hydropower capacity and is not included. IC_t^{dk1} is a dummy that assumes the value 1 when SE3 is import constrained from DK1. DK1 is the price area that produces the highest volumes of wind power. P_t^{se} is the cleared price in SE3. $\boldsymbol{S}_t$ is a vector of necessary controls, described in the next section. FE_t is a vector of fixed effects to account for unobserved time-variant variables. ε_t is the unobserved error. δ_0, α, β, γ and φ are parameters to be estimated, and the subscript A indicates that the parameters are related to *all* hydropower producers in Sweden, not just the dominant.

6.2.1 An IV-approach

Following our research question, we want to investigate how the predictability of wind may reduce the positive effect that wind has on competition. Therefore, we are not interested in import constraints in general, but the import constraints that are induced by high wind production in other zones, and in our specific case DK1. We will therefore apply an instrumental variables approach to effectively reduce the variation in IC_t so that our α-parameter will measure the effect on hydropower quantity of wind-induced import constraints. We will use the wind power prognosis of DK1 as instrument since this is the best prediction of wind power output at the time of the auction. The IC_t variable may also be endogenous to the model. When hydropower output in Sweden is low, this may lead to increased imports and consequently induce import constraints. The IV-approach proposed here accounts for such endogeneity.

Essential when applying any instrumental variable approach, is that each instrument must satisfy the two assumptions of relevance and exogeneity, often called the exclusion restriction. In a setting with an endogenous binary variable, that means the instrument must be able to predict the treatment. The relevance assumption can be tested[12], whereas the exclusion restriction must be argued for. The exclusion restriction assumption means that there should be zero covariance between the instrument and the error term of unobserved variables. That is, there should be no direct effect of the instrument on the dependent variable other than

[12] Cragg-Donald F-statistics are included in the results under Section 7

through the endogenous variable and controls. The exclusion restriction also means that the instrument must be exogenous —not depend on the model.

The wind prognosis data that I use as an instrument, is based solely on weather forecasts, and is therefore completely exogenous to the model. There are three ways through which wind in Denmark may affect hydropower output in Sweden. First, it may affect output by inducing import constraints and changing market power. Second, it shifts the aggregate supply curve on Nord Pool, making prices clear lower with potential effects on hydropower output. Third, wind in Denmark is likely highly correlated with wind in Sweden. Wind in Sweden may have an impact on hydropower production in Sweden through correlations with snow melting speed and reservoir inflows as well as to cooling speed effects of buildings. The first effect, through inducing import constraints is the effect we test in this thesis, and consequently corresponds to the relevance criteria. The second effect, through price, is accounted for since we include price in the model. The third effect, through correlation with wind in Sweden, we account for by including wind power predictions in Sweden as a control variable.

I use the price in SE3 as our price variable. Most of the time, prices in all price areas in Sweden are the same. At any hour, consumption in SE3 are between 60% and 70% of total consumption in Sweden, and SE3 is the area directly connected to DK1, making it the most appropriate price indicator. Price, however, does also suffer from a reverse causality issue, where price depends on hydropower output and hydropower output depends on price. I will use a demand shifter —forecasted demand[13]— as an instrument to address the issue. Forecasted demand is based on demand shifters such as weather forecasts, mainly temperature, and indicators of economic activity in the country, and is exogenous to the cleared price.

Since a large majority of the hydropower capacity belonging to the dominant actor is located in SE1 and SE2, and most consumption is in SE3, possibility to exercise market power is limited when SE2-SE3 is congested. Therefore, in the vector of controls I include an indicator for when SE3 is import congested from SE2 and an interaction indicator of import constraints from DK1 and SE2.

I also include hour of day indicators in the estimations to account for cyclical consumer behavior and wind.

6.2.2 Choosing Estimator

When estimating the effect of binding import constraints on quantity produced in hydropower plants —as specified in Equation 9— we want to find an estimator that is consistent and

[13]proposed by Kim and Knittel (2006) and used by Lundin and Tangerås (2017)

effective. The coefficient that is of interest is the coefficient of the binary variable for import constraints. Since we are particularly interested in the import constraints caused by wind power generation in the exporting area, I use the instrumental variables (IV) approach from Subsection 6.2.1, where in the first stage, we obtain the fitted values from a regression of import constraints on a measure of wind power predictions. The estimated parameter we get from using these fitted values as an independent variable in the second stage regression, can be interpreted as the effect on hydropower quantity caused by wind power through its impact on import constraints. In other words, the first stage in the equation is reducing the data in our import constraint variable to only include the variation caused by high wind power production.

The binary nature of our IC variable means that we will estimate an average treatment effect (ATE). Since the treatment in our case is binding transmission constraint, and it applies to the particular hour, the average treatment effect may be interpreted as the expected effect of a binding transmission constraint for a randomly drawn hour of the population. With a binary indicator as a main variable of interest, we would ideally use a non-linear estimator in the first step —this would ensure high efficiency. To keep consistency, then, we would have to follow a three step process according to: 1) Estimate the effect of wind power on import constraints under a maximum likelihood estimator (such as probit), predict the fitted values. 2) Use the obtained probabilities as an instrument for the import constraint variable in the first stage of a two stage least squares (2sls) estimation. 3) Estimate final coefficients in the second stage 2sls (Wooldridge, 2002).

The problem with applying the three step approach in our setting, is that we would like to include daily time fixed effects to account for the unobserved behavioral and structural changes over time. With a within-day estimator, we effectively divide the data in groups of 24 observations, which is likely too small for consistent estimates in a maximum likelihood model due to the incidental parameters problem (Lancaster, 2000). In our setting, there are two large benefits of using a within-day fixed effects estimator. First, it accounts for *all* behavioral aspects. This comes from the auction design, where the decision for 24 hours are made at a single point in time. Therefore, there is no time that passes between the submission of bids within a day, during which a producer or wholesaler could change strategy. After the bids are submitted, Nord Pool will clear prices and hold each producer accountable for producing the quantities allocated to them. Second, the Nordic electricity market develops rapidly. Over time, countries are added to Nord Pool, producers invest or divest, transmission lines and wind power is expanded in new regions. All these things, and many others, may affect the bidding strategy of producers. Therefore, bids submitted at separated points in time may not be comparable to each other.

Instead of the 3-step approach, Angrist and Pischke (2008) suggest to apply the ordinary linear 2sls estimator directly to a model with an endogenous binary indicator. The parameters estimated will still be consistent, and we can combine it with the fixed effects estimator, but we will lose some efficiency. With the large amount of observations in our sample, the incidental parameters problem outweighs the potential problem of efficiency. Therefore, the estimations of this thesis will primarily rely on the 2sls within day fixed effects estimator.

6.3 Data

In order to estimate the effect of transmission constraints on output of hydropower electricity, I download hourly data on total hydropower production by price area from Svenska kraftnät, the Swedish TSO. Through the ENTSO-E transparency platform, I get detailed data of hourly production on unit level from 12 of the largest hydropower plants in Sweden, all belonging to the dominant player, Vattenfall. This data has become available recently, and has to the best of my knowledge, never been used in research before. This data makes it possible to track the behavior of the dominant hydropower producer in Sweden, and compare it to the full data.

Nord Pool provides hourly data on zone-specific prices. Since transmission constraints cause a price difference between neighbouring zones, we can use this data to construct congestion indicators for all relevant zones. From the Nord Pool server, I also download wind power predictions for DK1 and Sweden. For secondary specifications and robustness checks, I also download hourly data on electricity flows between price areas and weekly ”water inflow to reservoirs” data.

6.3.1 Summary Statistics

The data set consists of 17448 consecutive hours from January 5, 2015 to December 31, 2016. This is all data made available to me from the ENTSO-E transparency platform. SE3 is import constrained from DK1 for 4898, which constitutes 28% of the hours in the data set. Out of the 727 days in the sample, 403 days, or 55.4% of the days, had at least one hour import constrained. Table 3 shows summary statistics for the variables used in the estimations. Note that the table also specifies the notation of estimated coefficients that will be used in the results tables.

Table 3: Summary statistics, hour of day indicators excluded

Variable	*Coeff.*	Mean	Std. Dev.	Min	Max
A. Output hydro SE123 (MWh)		7677.67	2549.57	1644.82	13085.42
D. Output dominant (MWh)		1871.43	849.70	0	3788.1
F. Output fringe (MWh)		5806.24	1944.68	887	12028
DK1-SE3 congested	α	0.29	0.45	0	1
Price SE3 (SEK)	β	244.63	113.87	3	2003
Forecasted wind prod SE (MWh)	γ_1	1811.05	1081.81	62.0	5293.0
SE2-SE3 congested	γ_2	0.05	0.21	0	1
Cong. interact. term	γ_3	0.01	0.08	0	1
Weekend	γ_4	0.29	0.45	0	1
Inflow SE (GWh)	γ_5	1315.02	1032.70	297	5222
Forecasted demand SE		15656.45	3277.73	8910	27558
Forecasted wind prod DK1		1198.27	901.11	11	3709.0

7 Results

7.1 Industry Wide Average Treatment Effects

Table 4 presents the estimated results for the specification in Equation 9. The dependent variable for all regressions in Table 4 is total electricity produced in price areas SE1, SE2 and SE3. To achieve comparable estimates, we use a log-log specification where all non-binary variables are expressed as natural logarithms. Through log approximation, we will interpret all coefficients as percentage effects on the dependent variable. The main parameter of interest here is the effect of import constraints into area SE3 in the top row of the table, α_A. In column (1), we present the results of an OLS estimation on within-day-transformed data. Under the assumptions of exogenous explanatory variables, we see that for the average hour of import constraint, hydro producers reduce their production by 2.74%. This thesis has argued, however, that the constraint must be predictable at the time of the auction, at noon the day before the actual power is generated, and further that congestion caused by wind power are highly predictable due to accurate wind power prognosis available to all stakeholders at the time of the auction. In column (2), I treat the congestion dummy as endogenous, and apply an instrument of the hourly wind power prognosis. The results, then, may be interpreted as the average treatment effect of congestion that is caused by wind, or more accurately predicted by the wind power prognosis. The effect, in comparison to that of the OLS estimate is considerably larger, with a reduction in output under the predicted constraints of 31.4%. This increase is in line with the a priori expectations discussed in Subsection 5.4.

Table 4: Main specification (Equation 9) results: Dependent variable is total quantity produced by hydropower producers in SE1, SE2 and SE3. Hour of day dummies are included in all regressions. Where applicable, DK1-SE3 constraints —α_A— is instrumented by prognosticated wind production in DK1. Price —β_A— is instrumented by SvK's predicted demand.

	(1) OLS	(2) IV	(3) IV	(4) IV	(5) OLS	(6) IV	(7) IV	(8) IV
α_A	-0.0274***	-0.314***	-0.258***	0.0745	-0.0814***	-0.264***	-0.197***	0.0424**
	(0.00842)	(0.0254)	(0.0539)	(0.0691)	(0.0255)	(0.0119)	(0.0113)	(0.0185)
β_A			0.174***	1.210***			0.247***	1.152***
			(0.0247)	(0.0597)			(0.00806)	(0.0234)
γ_{1A}	-0.0992***	-0.0999***	-0.0852***	0.00294	-0.118***	-0.109***	-0.0847***	0.00588
	(0.0107)	(0.00514)	(0.0111)	(0.0133)	(0.0165)	(0.00292)	(0.00279)	(0.00423)
γ_{2A}	-0.0334***	-0.0571***	-0.0940***	-0.314***	0.0650**	0.0306***	-0.0330***	-0.267***
	(0.0118)	(0.00573)	(0.0143)	(0.0429)	(0.0272)	(0.00557)	(0.00625)	(0.0177)
γ_{3A}	0.00335	0.241***	0.149***	-0.397***	0.101**	0.268***	0.110***	-0.467***
	(0.0225)	(0.0245)	(0.0567)	(0.125)	(0.0371)	(0.0151)	(0.0195)	(0.0582)
γ_{4A}					-0.0511***	-0.0568***	-0.0382***	0.0309***
					(0.0108)	(0.00382)	(0.00360)	(0.00506)
γ_{5A}					0.0197	0.00707	0.0765***	0.330***
					(0.0457)	(0.00688)	(0.00672)	(0.0115)
FE	Day	Day	Day	Day	Month	Month	Month	Month
IC endo.	No	Yes	Yes	Yes	No	Yes	Yes	Yes
P endo.			No	Yes			No	Yes
C-D stat		611.1	600.2	302.1		2279.9	2267.9	909.8
N	17448	17448	17448	17423	17448	17448	17448	17424

Robust standard errors in parentheses, clustered by day in (2), (3) and (4)
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

In column (3), price in SE3 is included and treated as an exogenous control. In column (4), we acknowledge the reverse causality issues that enter the estimation with price included, and treat the price as endogenous by including hourly forecasted demand to the list of instruments. When including the price in column (3), the effect is reduced compared to in column (2), but is still large with an average reduction in output of 25.8% under wind-predicted congestion. In column (4), the coefficient differs rather sharply from previous results. Although not statistically significant, we see a positive coefficient indicating that on average, a hydro producer increases output during the constrained hours. The coefficient corresponds to a 7.45% increase of production.

Column (4) is the results from estimating Equation 9 using the IV fixed effects estimator argued for in Subsubsection 6.2.1. The estimator used in column (4) is the preferred one, since it accounts for possible endogeneity in both IC_t and P_t.

It is important to distinguish between the two results in column (3) and (4). Since we use a different set of instruments in the fourth specification, we effectively change the variation in the endogenous variables used to estimate the results. In the first two IV estimations —(2) and (3)— the instrument was wind power prognosis in DK1 alone. This had the implication of a clear cut interpretation of α_A. In estimation (4), we are using variation in the import constraint that is created by high wind *and* by high demand on the importing side. The large difference observed between α_A in column (3) and α_A in column (4) may come from two sources:

1. Inconsistency in (3) for failing to account for endogeneity in price.
2. Different behavior of hydro producers when the import constraints are driven by high demand in the importing area. (4)

To test the robustness of results in column (4), I apply an alternative approach in Subsection 7.3. In the robustness check, I treat the import constraints as exogenous, but manually increase the level of wind to account for the issues listed.

For all estimations where price is included, we see that the effect of price, β_A on quantity produced by hydro producers is positive, large, and highly significant. This corresponds to the fact that hydro-producers maximize profit by choosing to produce when prices are high.

7.1.1 Including Reservoir Inflow Data

In columns (5) through (8) of Table 4, the same methods of estimation as in (1) through (4) are used. Here, however, I control for inflow to the water reservoir. The reservoir levels are important for hydroproducers since it is directly related to their opportunity cost and allocation decision. The reservoir levels also decide how much water there is available to defer to later periods. Therefore, if possible, we would like to include it in the estimations. Reservoir levels, are endogenous to the model, so I use the exogenous reservoir inflow data instead. Reservoir inflow data is only available on a weekly level. To maintain variation in the sample, I therefore allow for a longer time span of fixed effects, monthly fixed effects, and include a weekend indicator to control for large differences in consumer behavior during workdays and weekends. The coefficients for import constraints follow a similar pattern to the estimations in (1) to (4), with the notable exception of a significantly positive coefficient in estimation (8).

One should be careful when interpreting the estimates of specification (5) to (8) for at least two reasons. First, in a within month specification we are comparing all hours congested to all hours not congested within the course of a month. In the electricity wholesale industry, there are too many variables to account for over the course of a month. For instance, all things affecting bidding behavior on Elspot should ideally be taken into account. For instance, producers may sign direct contracts with corporate or national customers; structural elements of the market may change, such as the market entry or changes in ownership structure; transmission lines may open or break down etcetera. These and other issues affect how a producer supply her bids. With a within month setup, we compare hours congested in the beginning of March, to hours not congested in the end of March, these hours may or may not be comparable. When looking within day, however, all behavioral aspects are accounted for, since the bids for all 24 hours of the coming day are submitted simultaneously. Second, weekly data is quite rough in this industry, where bids are submitted daily, and producers have finer and more accurate prognoses of factors affecting inflow than the weekly data made public. Daily fixed effects better account for daily changes in water value than does the weekly estimate.

7.1.2 First-Stage Estimates

Cragg-Donald test statistics for testing weakness of instruments were included in Table 4. Comparing the test statistic to the critical values derived by Stock and Yogo (2005), we may under the assumption of independent and identically distributed errors reject the hypothesis of weak instruments for all conventional significance levels. Interesting, but not surprising, is that the Cragg-Donald test statistic is reduced when the price is treated as endogenous. In Table 5, we see that wind power prognosis has a very clear and significant effect on the transmission line becoming congested, whereas the demand forecast in Sweden does not. The Cragg-Donald figures reflect that the strength of the full set of instruments is decreased when the demand forecast is included, resulting in the lower statistic.

We should expect two things when considering Swedish demand's effect on import constraints. First, any effect of higher demand in Sweden should be positive. Higher demand in Sweden should not imply less flow from Denmark to Sweden but more, ceteris paribus, creating an increased likelihood of the line becoming congested. Second, since Denmark, with the exception of wind, produces electricity at the high end of the price range, any effect from increased demand in Sweden should happen in conjunction with wind power being produced. When no wind power is produced in Denmark, high demand in Sweden would first be served from Swedish and Norwegian hydro power, Swedish and Finish nuclear and Swedish wind. Only after these sources, Danish electricity could be imported to SE3. Even when prices clear at the level of Danish coal or gas fueled power, the Swedish thermal power plants would also produce, relieving possible congestion. Therefore, we would not expect as clear effect from Swedish demand, as we would from Danish wind. In estimation (8) of Table 5, we see a negative and significant effect of Swedish demand on import constraints, which may be a sign

Table 5: First stage regression results for DK1-SE3 congested —α_A—. Column numbers are matched to Table 4. Hour of day estimates have been excluded from the table.

	(2)	(3)	(4)	(6)	(7)	(8)
Wind pwr progn DK1	0.132***	0.132***	0.133***	0.164***	0.166***	0.164***
	(0.00604)	(0.0113)	(0.0112)	(0.00340)	(0.00345)	(0.00340)
Demand forecast SE			0.169			-0.0932*
			(0.113)			(0.0408)
Wind pwr progn SE	-0.0637***	-0.0642***	-0.0638***	-0.0755***	-0.0730***	-0.0757***
	(0.00946)	(0.0174)	(0.0172)	(0.00534)	(0.00534)	(0.00534)
SE2-SE1 congested	-0.0534***	-0.0517**	-0.0599***	-0.0763***	-0.0853***	-0.0705***
	(0.00783)	(0.0169)	(0.0159)	(0.00851)	(0.00953)	(0.00901)
DK1-SE3 x SE2-SE1	0.806***	0.808***	0.806***	0.861***	0.848***	0.867***
	(0.0318)	(0.0494)	(0.0488)	(0.0193)	(0.0199)	(0.0198)
Price SE3		-0.00743			0.0330*	
		(0.0293)			(0.0132)	
Weekend				-0.0206***	-0.0182**	-0.0248***
				(0.00616)	(0.00622)	(0.00641)
Reservoir inflow				-0.0553***	-0.0455***	-0.0626***
				(0.0118)	(0.0126)	(0.0123)
N	16387	16387	16362	16398	16398	16374

Robust standard errors in parentheses, clustered by day in (2), (3) and (4)
Hour of day has been excluded
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

of unobserved factors not being properly accounted for by the monthly fixed effects. The unexpected results of the first stage regression in estimation (8) is an argument corroborating the stance that the estimator in (4) is the most reliable.

From Table 6, showing the results of the first stage regression of our second endogenous variable, price, note that both instruments have significant effects on price. I have argued that price should be instrumented by a demand shifter, in order to exclude the variation caused by supply shifts to remedy the situation of reverse causality. However, from the first stage regression, it is clear that wind power prognosis —which can be seen as a supply shifter— has a significant effect on the price in the first stage. This is not a problem. Wind does not directly affect hydropower output. The way that Danish wind may affect Swedish hydropower output, is if hydropower producers take price or transmission constraints into consideration. Both these factors are explanatory variables in our specifications.

Table 6: First stage regression results for price —β_A—. Column numbers are matched to Table 4. Hour of day estimates have been excluded from the table.

	(4)	(8)
Wind pwr progn DK1	-0.0401***	-0.0354***
	(0.00634)	(0.00212)
Demand forecast SE	1.502***	1.494***
	(0.0616)	(0.0253)
Wind pwr progn SE	-0.0702***	-0.0727***
	(0.00838)	(0.00308)
SE2-SE3 congested	0.168***	0.183***
	(0.0300)	(0.0129)
DK1-SE3 x SE2-SE3	0.272***	0.309***
	(0.0772)	(0.0405)
Weekend		-0.00671
		(0.00359)
Reservoir inflow		-0.178***
		(0.00762)
N	16362	16374

Robust standard errors in parentheses, clustered by day in (2), (3) and (4)

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

7.2 Testing for Differences Between Dominant and Not Dominant Producers

According to the theoretical predictions, the sign on the α-coefficients should be negative if firms deviate from their ordinary bids and withhold production when import constraints become binding. On the industry level, we instead saw a positive coefficient. In this section, I make use of data from the European Network of Transmission System Operators for Electricity's (ENTSOE-E) transparency platform, and test whether or not the dominant producer in Sweden, Vattenfall, appears to exert more market power when its area of dominance becomes import constrained. Consider the following specifications:

$$ln(H_t^{se} - q_t^{se}) = \delta_{0F} + \alpha_F IC_t^{dk1} + \beta_F ln(P_t^{se}) + \gamma_F \boldsymbol{S}_t + \varphi_F FE_t + \nu_t \quad (10)$$

$$ln(q_t^{se}) = \delta_{0D} + \alpha_D IC_t^{dk1} + \beta_D ln(P_t^{se}) + \gamma_D \boldsymbol{S}_t + \varphi_D FE_t + \omega_t \quad (11)$$

Where q_t^{se} is the quantity output of the dominant Swedish hydropower producer, as denoted in Section 5. Equation 10 then represents the industry wide quantities less the quantities of the data set of the dominant hydropower producer —refer to this as the fringe production.

Table 7: Results from estimating Equation 10: Dependent variable is quantity produced by the fringe suppliers in Sweden. Hour of day dummies are included in all regressions. Where applicable, DK1-SE3 constraints —α_F— are instrumented by prognosticated wind production in DK1. Price —β_F— is instrumented by SvK's predicted demand.

	(1) OLS	(2) IV	(3) IV	(4) IV	(5) OLS	(6) IV	(7) IV	(8) IV
α_F	-0.0334***	-0.298***	-0.239***	0.123	-0.0814**	-0.269***	-0.207***	0.0250
	(0.00887)	(0.0271)	(0.0576)	(0.0778)	(0.0290)	(0.0127)	(0.0119)	(0.0193)
β_F			0.187***	1.338***			0.243***	1.180***
			(0.0268)	(0.0669)			(0.00841)	(0.0246)
γ_{1F}	-0.0952***	-0.0957***	-0.0788***	0.0256*	-0.122***	-0.111***	-0.0885***	-0.000861
	(0.0115)	(0.00552)	(0.0118)	(0.0145)	(0.0164)	(0.00314)	(0.00301)	(0.00441)
γ_{2F}	-0.0354***	-0.0571***	-0.0961***	-0.337***	0.0645**	0.0293***	-0.0325***	-0.271***
	(0.0132)	(0.00646)	(0.0160)	(0.0488)	(0.0294)	(0.00665)	(0.00710)	(0.0187)
γ_{3F}	-0.00309	0.214***	0.116*	-0.487***	0.0898**	0.260***	0.108***	-0.475***
	(0.0261)	(0.0259)	(0.0613)	(0.143)	(0.0368)	(0.0165)	(0.0199)	(0.0599)
γ_{4F}					-0.0524***	-0.0583***	-0.0396***	0.0331***
					(0.0126)	(0.00403)	(0.00382)	(0.00533)
γ_{5F}					0.0139	0.00216	0.0779***	0.369***
					(0.0513)	(0.00749)	(0.00741)	(0.0129)
FE	Day	Day	Day	Day	Month	Month	Month	Month
IC endo.	No	Yes	Yes	Yes	No	Yes	Yes	Yes
P endo.			No	Yes			No	Yes
C-D stat		566.5	556.7	278.3		2118.8	2115.2	864.4
N	16398	16387	16387	16362	16398	16398	16398	16374

Robust standard errors in parentheses, clustered by day in (2), (3) and (4)
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Equation 11 represents the quantity produced by the dominant producer. I use subscripts F or D to indicate relation to the fringe data set or the dominant data set. The capacity installed in the hydro power plants in the ENTSO-E data set, sums to 4328 MW or correspondingly 54.7% of Vattenfall's total hydropower capacity.

We should expect to see a negative α_D for the dominant producer, but not necessarily a negative α_F for the fringe producers. We should expect to see a lower (more negative) effect on the quantity from the dominant producer. The results from estimating Equation 10 and Equation 11 are presented in Table 7 and Table 8 respectively.

In accordance with the theoretical predictions, α_D is negative for all estimators, except for (8), where we observe a positive coefficient very close to zero. As predicted, the effect is larger (more negative) for all α_D (Table 8) compared to α_F (Table 7) except in the very basic OLS regression in (1).

Like argued before, (4) is the preferred estimator. We observe a positive effect for the fringe, with an average treatment effect of 12.3%. For the dominant producer, we observe a negative ATE of -7.47%. None of these estimates are significantly different from zero at any

Table 8: Results from estimating Equation 11: Dependent variable is quantity produced by the dominant supplier in Sweden. Hour of day dummies are included in all regressions. Where applicable, DK1-SE3 constraints —α_D— are instrumented by prognosticated wind production in DK1. Price —β_D— is instrumented by SvK's predicted demand.

	(1) OLS	(2) IV	(3) IV	(4) IV	(5) OLS	(6) IV	(7) IV	(8) IV
α_D	-0.0323***	-0.405***	-0.360***	-0.0747	-0.0951***	-0.304***	-0.222***	0.00412
	(0.0121)	(0.0390)	(0.0802)	(0.0882)	(0.0333)	(0.0188)	(0.0183)	(0.0248)
β_D			0.143***	1.067***			0.331***	1.267***
			(0.0348)	(0.0811)			(0.0127)	(0.0293)
γ_{1D}	-0.123***	-0.124***	-0.111***	-0.0273	-0.136***	-0.125***	-0.0939***	-0.00616
	(0.0166)	(0.00825)	(0.0172)	(0.0181)	(0.0190)	(0.00442)	(0.00425)	(0.00541)
γ_{2D}	-0.0358	-0.0665***	-0.0963***	-0.288***	0.0711	0.0320***	-0.0493***	-0.281***
	(0.0223)	(0.0100)	(0.0239)	(0.0479)	(0.0479)	(0.00908)	(0.0102)	(0.0214)
γ_{3D}	0.0528	0.359***	0.284***	-0.197	0.138**	0.328***	0.119***	-0.468***
	(0.0349)	(0.0396)	(0.0825)	(0.134)	(0.0629)	(0.0243)	(0.0326)	(0.0728)
γ_{4D}					-0.0742***	-0.0807***	-0.0554***	0.0180***
					(0.0141)	(0.00585)	(0.00563)	(0.00690)
γ_{5D}					0.0103	-0.00330	0.0997***	0.389***
					(0.0715)	(0.0110)	(0.0112)	(0.0158)
FE	Day	Day	Day	Day	Month	Month	Month	Month
IC endo.	No	Yes	Yes	Yes	No	Yes	Yes	Yes
P endo.			No	Yes			No	Yes
C-D stat		566.1	556.6	277.8		2105.9	2105.3	866.2
N	16316	16305	16305	16280	16316	16316	16316	16292

Robust standard errors in parentheses, clustered by day in (2), (3) and (4)

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

conventional levels, but it is interesting to see if they are significantly different from each other.

To test the null hypothesis of $\alpha_F = \alpha_D$, I estimate Equation 10 and Equation 11 jointly with a multiple-equation GMM estimator (Hayashi, 2000). χ^2-scores for equality of α_F and α_D are reported together with corresponding p-values in Table 9. We reject the null hypothesis at the 1% significance level for specifications (4) and (5), at the 5% level for specification (6), at the 10% significance level for specification (3). For the remaining specifications, we cannot reject the hypothesis of equal conduct between the dominant and the fringe producers. I have argued that the specification that best captures the effect of the research question, is the one reported in column (4) of Tables 7-9. Table 9 shows that although the effect of wind-generated import constraints were not significantly different from zero, the dominant producer generates significantly less electricity than its competitors during congested hours.

Table 9: χ^2-test testing the null hypothesis of zero difference between α_F and α_D

	(1) OLS	(2) IV	(3) IV	(4) IV	(5) OLS	(6) IV	(7) IV	(8) IV
χ^2-stat	0.01	2.77	3.38	8.39	7.07	5.47	0.87	1.10
P-value	0.924	0.090	0.0661	0.0038	0.0078	0.0194	0.3520	0.2944
Fixed effects	Day	Day	Day	Day	Month	Month	Month	Month

7.2.1 Economic Impact of Results

To measure the economic impact of withholding capacity in an import constrained area, such as the welfare effect, we would need information of the shape of the regional supply and demand curve, or at least the slope at the intersection of the curves. In the Nordic market, such data is not made public. From the auction design, however, we do know that withholding capacity must inherently increase prices. In Subsection 5.3, we showed that there is a deadweight loss to society from shifting water and production to periods with less price-elastic demand.

In our case, we see a negative effect on quantity for the dominant producer, but a positive effect for the fringe producers. Overall, as seen in Subsection 7.1, the two effects counteract each other. In Section 8, I discuss reasons for the positive effect of import constraints on fringe producers' output.

7.3 Robustness Check

In Subsection 7.1 a potential problem of the IV-specification was discussed. With a demand shifter as an instrument, the interpretation of the import constraints as being caused by wind is questionable. Since price is clearly endogenous, and suffer from reverse causality issues, we do not want to exclude its instrument. Instead of using an IV approach to isolate the congestion caused by wind, we instead run the estimations on subsets of the sample. The data is sorted by level of forecasted wind power production and cut off at the 25th, the 50th and the 75th percentile (p25, p50 and p75). Table 10 shows the coefficients for the full sample, and the sample divided in the dominant producers output and fringe production.

The first row shows the "industry wide" average treatment effect of import constraints from DK1 to SE3. For p25 and p50, the effects of import constraints are very small and not statistically significant. For import constraints when wind is in the 75th percentile, we see a considerably larger (negative) effect of -6.13%, significantly smaller than zero at the 5% level. When import constraints are binding, and wind forecasts are high, the overall hydro power

Table 10: Robustness check treating the import constraint as exogenous and restricting the sample to different levels of wind power prognosis.

	p25	p50	p75	p25	p50	p75
α_A	-0.00131	0.00286	-0.0613**	-0.0417***	-0.0375***	-0.0695***
	(0.0128)	(0.0169)	(0.0246)	(0.00668)	(0.00853)	(0.0120)
α_F	-0.00317	0.00604	-0.0508**	-0.0453***	-0.0370***	-0.0597***
	(0.0139)	(0.0179)	(0.0251)	(0.00718)	(0.00908)	(0.0128)
α_D	-0.0124	-0.0206	-0.0890***	-0.0619***	-0.0703***	-0.131***
	(0.0154)	(0.0210)	(0.0343)	(0.00896)	(0.0117)	(0.0171)
Fixed effects	Day	Day	Day	Month	Month	Month
Price endo.	Yes	Yes	Yes	Yes	Yes	Yes
χ^2-score $\alpha_F - \alpha_D$	0.55	2.87	2.25	6.81	17.30	35.91
P-value $\alpha_F - \alpha_D$	0.4578	0.0961	0.1333	0.0091	0.000	0.000
Share hours IC	0.34	0.41	0.47	0.34	0.41	0.47
Cragg-Donald F	1774.8	940.6	296.6	3429.0	2147.8	1129.3
N	12288	8194	4074	12304	8209	4082

Robust standard errors in parentheses, clustered by day when FE = Day

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

producers in Sweden withhold some production. The pattern is similar for the non-dominant producers. Turing to the dominant producer, however, we see that Vattenfall withholds production when constraints are binding, even when wind is relatively low. The coefficient decreases from -1.24% and -2.06% to reach -8.90% at the 75th percentile, significant at the 1% level. A reasonable assumption is that a larger share of the import constraints are caused by high wind production the higher the wind production is. Under this assumption, firms seem to withhold more capacity when the transmission line becomes congested by excessive wind production, than when the constraints are driven by high demand in the importing area.

Two reasons that may cause the behavior have been discussed earlier. First, when the congestion is caused by wind, the competitive situation changes, firms can now freely bid on their residual demand without risking an increase in wind power imports that lowers the price and serves a larger share of the demand. Second, congestion caused by wind may be more predictable. Since the bids are submitted and prices and quantities cleared the day before the actual trade, the electricity producer must have a good sense of which hours the transmission lines will be congested. The wind power prognosis is rather accurate, and is relatively easily compared to transmission line capacities to form a good prediction of which hours will be congested. For the estimations with monthly fixed effects, we see the same pattern, but with all parameters being highly significant.

The χ^2-scores and p-values reported in Table 10 test the hypothesis of no difference between α_F and α_D. In the setting with daily fixed effects, the hypothesis of equal effect sizes cannot be rejected (accept for p50 at the 10% level). In the specification with monthly fixed effects, differences between the dominant producers and other producers are significant for p25, p50 and p75. Cragg Donald statistics show that we can reject the hypothesis of a week instrument, the statistic is naturally decreasing with sample size.

Overall, the results in the robustness check are in line with the theoretical predictions. Furthermore, the α_D-estimate in the p75 sample seems to be close in size to α_D in Subsection 7.2.

8 Discussion

The results presented in column (4) of the tables in Section 7, together with the robustness check results in Subsection 7.3 are the most reliable estimates. In column (4), we look within day to account for unobserved changes over time, and have valid instruments for the endogenous variables to make sure the estimator stays consistent. A potential problem with column (4), is that the interpretation of α may not solely be attributed to effect on wind-generated congestion. In Subsection 7.3 —as predicted— we see that the effect from the dominant producer is increasing in absolute terms with wind power prognosis. When a larger share of the congested hours can be attributed to wind, the dominant producer seems to withhold more production.

We have not thoroughly discussed the positive coefficient of the fringe. One possible explanation of a positive effect should be considered if we assume a competitive fringe, i.e. that all hydro power producers other than Vattenfall are competitive price takers, with little ability to affect prices, but ability to allocate production over time-periods. Førsund (2013) argued that an agent in the competitive fringe, with unlimited ability to allocate production to different time periods, would choose to produce everything in the period with highest price. Now, no producer has unlimited ability to allocate water over time, yet following the same logic, a competitive producer that counts on the dominant producer to withhold production, would allocate as much production as possible to the congested periods in order to extract as much profit as possible from the resulting high price. Another explanation of a positive coefficient is if we have some unobserved omitted variable that causes an upward bias in our estimation of α. In such a case, the significant difference between α_D and α_F would strengthen the suspicion of exercised market power from the dominant producer.

8.1 External Validity of Results and Sample Issues

The data selection methods and standard errors of results warrant discussion. Standard errors are normally calculated to give an idea of the precision of the estimator. The standard errors are for instance used to calculate the χ^2-statistics I have used to test the hypothesis of difference of average treatment effects between estimates. The standard errors are constructed under the assumption that we have a random sample of a very large population. The standard error will then be key to deciding the p-value, related to the probability that the effect of the sample also holds in the true population. For the standard error to be relevant, we must first define the population onto which we want to extrapolate our results. If we consider Sweden in 2015-2016 to be the population, then our sample equals the population, and the standard error looses relevance. The average treatment effects in the sample *are* the average treatment effects of the population. In fact, if one adjusts the standard errors for a finite population, the standard errors become zero when the sample size equals the population size (Bondy and Zlot, 1976).

If we instead want to claim external validity of the results, either saying that the results hold for the same countries but in different points in time, or if we want to infer the effects to some other country, then standard errors are theoretically relevant. In our case, however, they do not say much, since our sample is not randomly drawn from any defined population other than the one that equals the sample. Statistically then, we cannot extrapolate the results to other countries or points in time. One could, however, argue qualitatively that the results may hold because of similarity between markets, this would need to be confirmed by similar studies in these markets.

Regarding the data set from ENTSO-E, with prodution data on the unit level. We have used this as representative of the behaviour of the dominant producer. The data includes approximately half of actual Vattenfall hydropower production. If we assume that the dominant producer adheres to a similar conduct across the unobserved power plants as across the observed power plants, our estimated differences between the dominant producer and the fringe are underestimated. This comes from the fact that approximately half of the production of dominant producers are included in the sample of the fringe.

One can think of other plausible scenarios too. First, all capacity in the ENTSO-E data are from generators in price areas SE1 and SE2. The transmission capacity between these areas is relatively large, and do not as often get congested. Even so, Vattenfall also owns capacity in price area SE3, but volumes produced by SE3 generators are not reported to ENTSO-E. In a hypothetical scenario, Vattenfall may choose to increase production in SE3, and decrease production in SE1 and SE2, to avoid having the transmission lines between the areas congested. In such a case, our results would be overestimated. On the other hand, if one is cynical, a dominant producer has even more incentives to withhold production in the generators that are not subject to public scrutiny. If that is the case, the difference would be even greater than what can be seen in this thesis.

Finally, this thesis does not aim to measure abuse of market power as mark-ups in general, but instead looks at difference in market power between unconstrained and constrained times. If, as suggested by Lundin and Tangerås (2017), hydropower producers in Sweden do exercise market power in general, regardless of import constraints. Then this thesis measures the difference in market power between two specifically defined regimes, without discrediting the results of other studies that have found evidence of market power.

9 Conclusion

This thesis has analyzed the effects on competition of wind-induced congestion between geographical regions. Focus has been on the link between Danish DK1 —the region with the most wind production— and Swedish SE3 —the region with the highest electricity consumption. In the period of 2015–2016, the dominant hydropower producer generated relatively less electricity than producers with smaller shares of total capacity when import constraints from wind power were binding. The dominant hydropower producer withheld quantity equivalent to a 7.47% reduction under hours that were import constrained due to excessive wind production in Denmark. The estimate is not significantly different from zero in a two-sided test. The estimate is statistically different from the estimate of non-dominant producers at the 1% level in a two sided test.

When looking at the data filtered by the 75th percentile of wind production, we find that the dominant producer reduces output by 8.9%. The measure is statistically different from zero at the 1% level. Filtering on the 25th and 50th percentile render non-significant negative coefficients.

Overall, there are signs of different behavior between the dominant producer and the fringe producers when import constraints become binding. This may indicate that market power is being exercised by the dominant producer.

Expansion of transmission lines reduces the possibility for locally dominant players to exercise market power. When market power is not substantial, the cost of expanding transmission lines may or may not be larger than the loss to dead weight loss of strategic conduct of a dominant agent. Either way, the potentially beneficial effect on competition should be included in calculations when planning transmission expansion. Furthermore, with a future discontinuation of nuclear electricity production, the shares of wind and hydropower will increase and their interdependence will intensify. Under such conditions, the market power of hydroproducers will increase, and losses to society may be exacerbated. With more detailed data, market power in relation to bottle necks in the Nordic region could be identified with better accuracy. Many countries, such as Italy (Bigerna et al., 2016) and Canada (Wolak, 2015) make available bidding curves at the price area level. Such data enables more accurate methods of measuring market power as a consequence of congestion. I encourage Nord Pool to release zone specific bidding data.

10 References

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