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ZONAL PRICING AND DEMAND-SIDE BIDDING IN THE NORWEGIAN ELECTRICITY MARKET

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June 29, 1999

Abstract

This paper analyzes prices in the day-ahead electricity market in Norway. We consider the hypothesis that generators are better able to exercise market power when transmission constraints bind, resulting in smaller, more-concentrated markets. We test this hypothesis by comparing equilibrium prices across periods with different demand elasticity and with and without binding transmission constraints. We find some empirical evidence that prices in local markets are higher during constrained periods when demand is less elastic.

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1. INTRODUCTION

Norway was among the first countries to restructure its electricity sector in the early 1990s, and the market-based reforms have generally been considered successful. Compared to other countries that have instituted restructuring reforms, such as the UK, Norway has not made wholesale changes to its market rules or structure since deregulation in 1991 and the regulatory agency has played a relatively passive role. For instance, regulators do not seem to be concerned about market power. Apart from an investigation of one pricing incident in 1992, there has been no significant regulatory action.

Norway's success has led policy makers in other locations to consider adopting certain attributes of the Norwegian market design. At the same time, the low prices and lack of market power have been attributed to the fact that the country relies almost entirely on hydroelectric resources. It is generally assumed that hydroelectric markets are less prone to market power [Halseth, 1999]. It is also extremely difficult to look for direct evidence of market power by measuring the difference between prices and marginal costs in a hydro system. Since the variable cost for a hydropower producer is the opportunity cost of water, a function of expectations about future market conditions, it is impossible to measure precisely.

This paper considers evidence of market power in the day-ahead electricity market in Norway with three objectives. First, we aim simply to describe pricing in the market and consider the evidence of market power. Second, we assess the extent to which market design decisions have influenced the exercise of market power. We focus on two specific aspects, zonal pricing, whereby prices in different geographic areas vary to reflect constraints in the transmission system and demand-side bidding, which permits customers to commit to reduce their demand as prices rise. Third, we describe and implement a methodology for assessing market power that does not rely on marginal cost data. Our methodology is simple and has parsimonious data requirements, both important consideration in any deregulated environment.

In competitive electricity markets, generators need access to the transmission system in order to deliver electricity to demand centers. Transmission systems have large economies of scale and important network properties. Given their natural monopoly characteristics, transmission systems in all restructured electricity markets to date have remained either state-owned or regulated monopolies. The way in which access to the transmission grid is allocated can affect outcomes in the competitive generation market. One approach has been to designate separate markets whenever the transmission system becomes constrained and allow prices in those markets to reflect the externalities created on the system by consumption and production at every location [Schweppe et al, 1988; Hogan, 1992; Harvey et al, 1996]. Variants of that approach are nodal and zonal pricing.[1]

Nodal and zonal pricing promote allocative efficiency because both producers and consumers receive signals about the price of power in their local area, which is the relevant market for electricity when exchange with other areas is constrained. However, it is likely that generators are better able to exercise market power when they operate in a smaller market due to transmission constraints that physically separate them from other regions [Joskow and Tirole, 1999; Borenstein et al., 1998].

Alternatively, in a system without zonal pricing, generators are separately compensated if they are either constrained on or off. Depending on the compensation scheme, generators may have strong incentives to raise prices when they are constrained to run, and the price increases may be shielded from the demand side and difficult for the regulator to observe. Nodal or zonal pricing makes any exercise of market power easier to detect and exposes suppliers to demand elasticity.

Regardless of the transmission pricing scheme, demand side bidding has been proposed as an effective means to mitigate market power in electricity markets [Borenstein and Bushnell, 1997], but it has not been widely adopted outside of the Nordic markets. While other markets such as the California Power Exchange and New Zealand

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[1] Nodal pricing refers to a system where prices at any demand or load node are allowed to vary, while under zonal pricing, the nodal prices are aggregated across several zones. In Norway, the zones are

permit the system operator to switch off some types of load at predetermined prices, consumers are not permitted to vary the prices at which they are willing to curtail demand.

Norwegian hydro generators could exercise market power in several ways. The clearest example of market power would be if generators spill water without generating electricity in order to reduce storage and thus increase future prices. We study whether generators bid prices higher than their costs. Since variable costs are hard to measure in a hydro dominated system, we restrict our attention to measuring whether generators exercise *more* market power under certain circumstances. Our aim is not to measure the exact price-cost markup, but rather to determine, based upon publicly available data, whether there is evidence that generators are exercising market power. We do this by comparing equilibrium prices across periods with different demand elasticity and with and without binding transmission constraints.

For one local area, we find that the price increases due to transmission constraints are larger when demand is less elastic. Our results have implications both for the effects of transmission capacity on generators' ability to exercise market power and for the efficacy and desirability of demand side bidding. Also, since the methodology we use does not require cost information, it could be important in deregulated thermal markets, where information on costs may not be publicly available.[2]

The rest of the paper proceeds with a description of the Norwegian electricity sector in Section 2. Section 3 presents a model of a hydro producer that trades over a fixed capacity transmission line with a thermal generator. The model emphasizes the role that attributes of hydro plants play in determining plant-level marginal costs. The model also demonstrates the forces affecting the hydro producer's incentives to exercise market power. Section 4 lays out our empirical approach to identifying market power. Section 5 describes much of the data we have assembled on the industry, and Section 6 presents our

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allowed to vary and thus the distinction between a nodal or zonal system is less clearly defined. For the sake of brevity, we refer to the Norwegian system as "zonal pricing."

[2] To date, the deregulated electricity systems have adopted rules for varying amounts of information disclosure, ranging from full disclosure of all bids to disclosure of only the clearing price. Note, however, that bids do not necessarily reflect costs.

empirical results. In Section 7 we discuss several other incidents that have led to speculation about market power and use them to comment on the shortcomings of the methodology we implement in the previous section. Section 8 provides a brief conclusion.

2. INDUSTRY DESCRIPTION

The Energy Act of 1991 redefined the regulatory environment of the Norwegian electricity industry. The Act removed the monopoly franchises that endowed local utilities with exclusive delivery rights and introduced competition in electricity generation and marketing. Because of their natural monopoly characteristics, transmission and distribution remain regulated by the Norwegian Water and Energy Administration (NWE). While some municipalities are still vertically integrated into transmission, distribution, generation and marketing, there is strict accounting separation of transmission and distribution, which are regulated, from generation and marketing, which are not regulated. The largest state-owned firm was split to form Statkraft, a generation firm and Statnett, a transmission company. This section proceeds by describing the administrative, financial and physical operations of the new market.

2.1 System Operation

The major transmission company, Statnett SF, owns 70 percent of the Norwegian transmission grid (132 kV and above). Statnett is also the system operator (SO). All generators submit information to the SO about their production plans to meet bilateral and day-ahead market commitments. Generators and consumers are required to plan to meet all commitments they have made. The SO penalizes generators and consumers who systematically bid quantities different from their actual generation or consumption. Statnett operates a real-time market (the Regulation Market) and uses this market to settle imbalances in real time.

The SO uses the real-time market in two ways – Up-Regulation (increase in generation to meet an unexpected increase in demand or a plant outage) and Down-Regulation (reduced generation to meet a decrease in demand). The SO distinguishes between Regulation used to respond to deviations from zone-wide forecasted demand (Ordinary Regulation) and Regulation used to relieve intra-zonal transmission constraints or meet demand for ancillary services (Special Regulation). Consumers pay for any differences between their actual consumption and quantities contracted on the day-ahead market at the clearing price for the Regulation market. If a plant that does not fall in the merit order for the Ordinary Regulation Market is required to operate in order to relieve transmission constraints or for ancillary services, Statnett pays the plant the difference between its bids and the Regulation market price.

On average the market for Ordinary Regulation was in balance over 1998 with a net trade of –13.6 MWh. Gross trade was higher at 173 MWh. There was no (reported) trade in any area for 7.4 percent of the hours while there was no trade for 25.8 percent of the hours in the area markets. The Special Regulation market reported a net trade of 34.5 MWh and a gross trade of 47.2 MWh.

When the SO expects major transmission lines to be constrained for three or more days, it designates geographical zones for the day-ahead market. Intra-zonal transmission constraints expected to last less than three days are relieved using the Regulation Market. Market participants are required to buy and sell electricity at the zonal price. Bilateral contracts across regions have to be bid into the day-ahead market as sale in the generation region and purchase in the delivery region. The difference in prices between the regions represents a congestion charge. The congestion charge times the aggregate transmitted volume represents a merchandising surplus collected by the SO and passed on to the transmission owners. Since the income of transmission companies is regulated, the surplus is used to lower the access price for transmission lines.[3]

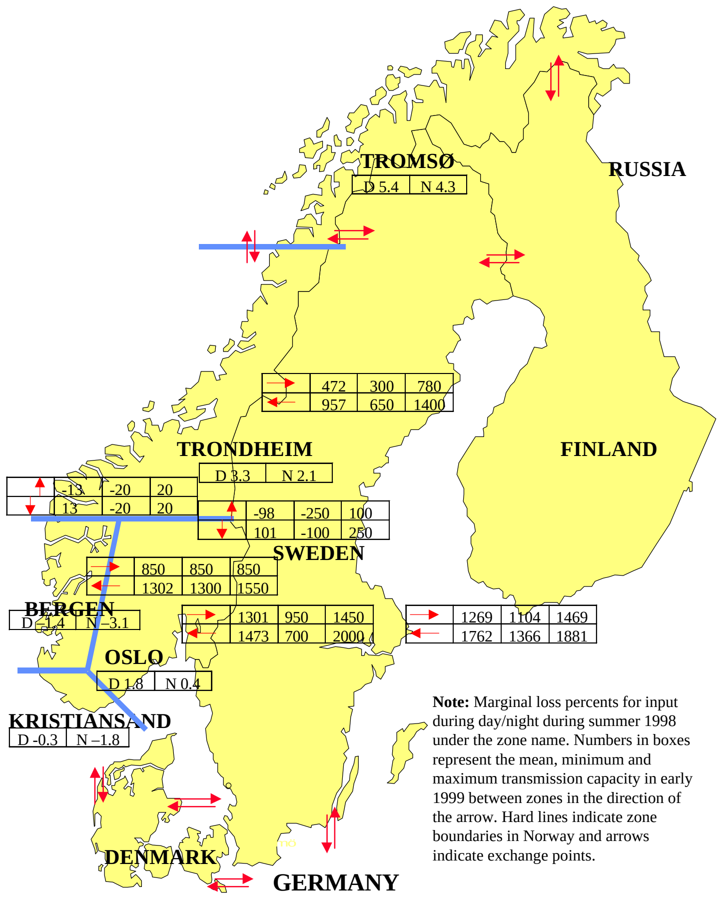
Physical power losses, due to resistance on the transmission lines, are accounted for by nodal marginal loss percents to both inputs and withdrawals from 144 nodes in the grid. The loss percent, set every two months, varies by time of day and node. Payments for losses introduce a difference between the day-ahead price and the final price

[3] The England and Wales pool does not explicitly account for transmission constraints with appropriate price signals. Argentina and New Zealand have adopted some form of zonal pricing, as have the Pennsylvania-New Jersey-Maryland (PJM) pool and other markets in the United States.

generators receive or customers pay. The marginal loss percents for input and withdrawal are equal and opposite, and the charge is calculated as a fraction of the system-wide price and *not* of the price in the local zone. Normally the loss percents for input to the grid are highest in regions with surplus generation.

Figure 1 shows the most common zonal borders, marginal loss percents and transmission capacities between the zones in Norway.

Figure 1: Price Zones in the Nordic Market



Up to five different areas, Bergen, Kristiansand, Oslo, Tromsø and Trondheim, are identified within Norway as indicated in Figure 1. The designation of zones changes from week to week and are announced to market participants on Wednesdays. For instance, in some weeks only three distinct zones are designated, if Oslo, Bergen and Kristiansand are all placed in the same zone. Within a week, the extent to which prices actually vary across zones depends on the market equilibrium, transmission capacities and the demand for inter-zonal transmission. As we document below, it is rare for the five areas to be separated into five different price zones during the same hour (see footnote 19).

2.2 Nord Pool

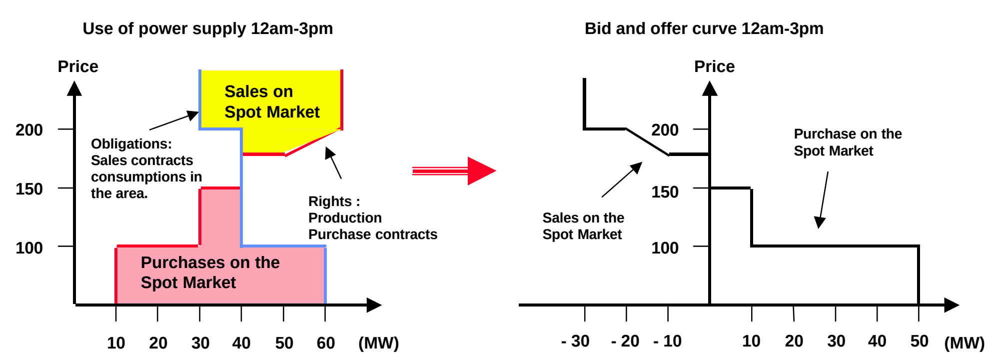
Nord Pool, ASA, runs the largest organized electricity market in Norway. Nord Pool is a successor to the Norwegian pool that was formed in 1971 as a result of the merger of five regional pools. In 1991, Statnett Marked, a subsidiary of the grid company, Statnett SF took over ownership of the Norwegian pool. The pool was also opened up to new entrants, such as smaller generators, retailers, traders and large consumers. In 1996, a joint Norwegian-Swedish pool was formed following deregulation in Sweden. Statnett and Svenska Kraftnat, the Swedish grid company, now equally own the joint pool, Nord Pool ASA. The Finnish pool ElEx became a part of Nord Pool in 1998. There are also substantial exchanges between the Nord Pool area and Denmark, Germany and Russia. Trading through Nord Pool is voluntary and, unlike England and Wales where all energy must be offered through the pool, only a part of the actual production trades on the market.

Nord Pool organizes two markets, Elspot and Eltermin, and also settles contracts from the Regulation market organized by Statnett. Elspot is a day-ahead market for physical deliveries. Eltermin is a forward and futures market and opens trades three years in advance of scheduled delivery.[4] Many independent brokers also trade various energy contracts, though most of their volume consists of trades in bilateral contracts. The fraction of energy traded in the day-ahead market has increased from about 15 percent in 1995 to 22 percent in 1998. In 1998, the average volume on the Elspot market was 6400 MWh per hour.

In Elspot, a trading day is divided into 24 hourly markets. Market participants provide separate bids for these 24 hours and the market clears separately for each of these

24 hours. Each participant provides a piece-wise linear bid schedule, where quantity is measured in MW and price in Nkr/MWh by 12 noon for delivery the following day. Nord Pool determines the clearing price for each market by 2:00 p.m. at which time the market closes and final clearing prices are determined. All contracts become binding at this point and Nord Pool initiates settlement of these contracts [Nord Pool, 1998].

Figure 2: Bidding Format and Demand-Supply Curve



Aktør : Aker Energiverk
Week : 10/95
Area : B

Bid/offer valid for : (cross off)

Mon.	Tues.	Wed.	Thurs.	Fri	Sat.	Sun.	Whole week
			x				

Time From - To	*0*	*100*	*101*	*150*	*151*	*175*	*176*	*200*	*201*	*900*
12-15	50	50	10	10	0	0	-10	-20	--30	-30

[Source: Nord Pool, 1998]

The bids from each of the participants provide a schedule of how much the bidder is prepared to sell or buy at different prices. For example, consider a generator that has a bilateral (non price-dependent) contract to supply 30 MW. In addition, it has a contract to supply 10 MW conditional on the spot price being below 200 Nkr/MWh and another 20 MW conditional on the spot price being below 100 Nkr/MWh.[5] The firm has a choice over whether it generates electricity itself or buys from Elspot to meet these contractual

[4] The futures market trades a variety of futures and forward contracts, ranging from seasonal blocks to weekly peak and off-peak contracts. All contracts on the Eltermin are valid anywhere in Norway. Some contracts had a peak open interest of about 20 percent of actual consumption in their load block.

[5] US $1 is approximately 7.7 Nkr (Norwegian kroner).

obligations. For the sake of illustration, assume that the firm would like to sell into the spot market at prices above 175 Nkr/MWh and buy at least a part of its obligations from the pool at prices below 175 Nkr/MWh. The firm could prepare a bid as shown in Figure 2. Consumers or their distribution companies prepare similar bids for purchases.

Generally, if there are no transmission constraints, the Nord Pool area is a combined market and market participants can buy or sell electricity at the same price anywhere in the area. If the system operator designates zones, Nord Pool arranges separate Elspot markets for each zone. Nord Pool first calculates a theoretical unconstrained price based on all submitted bids, without considering transmission constraints. If transmission constraints are binding Nord Pool adjusts prices upwards in deficit areas and downwards in surplus areas until transmission constraints are satisfied.

2.3 Retail Markets

End-users are billed separately for energy and distribution charges. Local distribution companies have a monopoly over distribution services. Consumers are free to buy energy from either the local supplier or from a large number of external competitors. Retail competition has led to a variety of contract terms, ranging from 3-year fixed price contracts to contracts reflecting hourly spot prices.[6] For the purposes of hourly billing, consumers either have a time-of-day meter or agree to be profiled according to the actual monthly consumption patterns of similar consumers in their area.

Table 1 shows the demand in each consumer category at the national level by region.[7] Metal and chemical manufacturing firms account for more than 50 percent of the consumption in the Bergen area. These firms are required to run continuously and have a flat load duration curve. Pulp and paper factories and some large apartment complexes with central heating systems that own boilers can substitute between electricity and oil or wood on a daily or weekly basis [Hornnes, 1995]. Residential, commercial and other industries account for more than 80 percent of the annual demand in Oslo and Tromsø.

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6 The website www.konkurransetilsynet.no gives an indication of contracts available and the numerous suppliers in the retail market.

7 The regions do not correspond precisely to the regions in figure 1. However, the distribution of end-user groups is likely to give a reasonable illustration of the regional patterns.

Table 1: Demand by Consumer Category, 1994

Region	Metal & Chemicals		Boilers		Residential & Other		Total
	GWh	%	GWh	%	GWh	%	
Oslo	5,542	11.2%	3,955	8.0%	40,147	80.9%	49,644
Kristiansand	3,604	29.2%	567	4.6%	8,184	66.2%	12,355
Bergen	11,095	51.9%	452	2.1%	9,811	45.9%	21,358
Trondheim	8,895	40.3%	662	3.0%	12,516	56.7%	22,073
Tromsø	864	11.7%	191	2.6%	6,342	85.7%	7,397
Norway	30,000	26.6%	5,827	5.2%	77,000	68.2%	112,827

Source: Hornnes (1995).

2.4 Generating Plants

Norway's generation capacity of about 23,000 MW consists almost entirely of hydroelectric generating plants. In a normal year hydroelectric plants generate roughly 113,000 GWh. Some pulp and paper factories own wood-fired thermal plants that operate off the grid and generate about 750 GWh per year. Almost all of the hydroelectric plants were built before deregulation and numerous state enterprises, counties and municipalities still retain ownership and control over about 70 percent of total generating capacity. The remaining capacity is owned by private firms, which may also have partial state ownership.

Norwegian generating capacity is distributed between a large number of small firms. The four largest Norwegian firms, Statkraft SF, Norsk Hydro AS, Oslo Energi AS and Bergenshalvøens Kommunale Kraftselskap (BKK) together generated 54,300 GWh out of a total generation of 123,490 GWh in 1995 (CR_4 = 44 percent). In 1995, the largest Norwegian firm, Statkraft, was responsible for 25.6 percent of total Norwegian generation or 12.5 percent of the generation in the joint Norwegian-Swedish market; in Sweden, the largest firm, Vattenfall AB, generated 51.7 percent of Swedish generation or 29.3 percent of the generation in the joint market. In the joint Norwegian-Swedish market the four firm concentration ratio was 55.2 percent. Table 2 contains detailed information about the largest generating companies in Norway and concentration levels by region.

Table 2: Largest Firms and Concentration Ratios (GWh)

	Bergen	Kristiansand	Oslo	Trondheim	Tromso
Statkraft	4,339		10,461	9,843	3,185
BKK	5,958				
Norsk Hydro	2,455		7,159		
SKL	1,375				
Lyse Kraft		4,082			
Vest-Agder		2,732			
Kristiansand		2,207			
Aust-Agder		1,998			
Oslo Energi			7,714		
Hafslund			2,457		
Trondheim				3,176	
Nor-Trondelag				2,303	
Sor-Trondelag				1,582	
Tromskraft					1,338
Nordkraft					586
Finnmark					461
Others	4,147	2,732	20,051	5,934	1,382
Total	18,274	13,751	47,842	22,838	6,952
CR4	77%	80%	58%	74%	80%
CR1	33%	30%	22%	43%	46%

Source: Samkjøringen (1992)

The share of the four largest firms (CR_4) varies from 58 percent in Oslo to 80 percent in Kristiansand and Tromsø. The share of the largest firm (CR_1) varies from 22 percent in Oslo to 46 percent in Tromsø. Kristiansand is the only market in which Statkraft is not one of the four largest firms. Since the configuration of zones changes from week to week the concentration ratios also change over time. In Table 2, we chose the most common boundaries for the zones. Bergen, especially, occasionally is in a much smaller zone and can have a much higher concentration (CR_4 = 93 percent and CR_1 = 58 percent).

Hydroelectric plants usually have a storage reservoir to even out the flow of water between dry and wet seasons. However, the relation between annual energy production and turbine capacity differs substantially from plant to plant. Plants that need to run fewer hours in order to exhaust their storage or to avoid spillage can choose to do so during the highest price periods, thus indicating a higher marginal value for water. Conversely, plants that need to run more hours in order to exhaust storage are forced to operate in lower price periods, indicating a lower marginal value of water. Storage and installed capacity characteristics therefore determine the shape of the regional cost functions.[8]

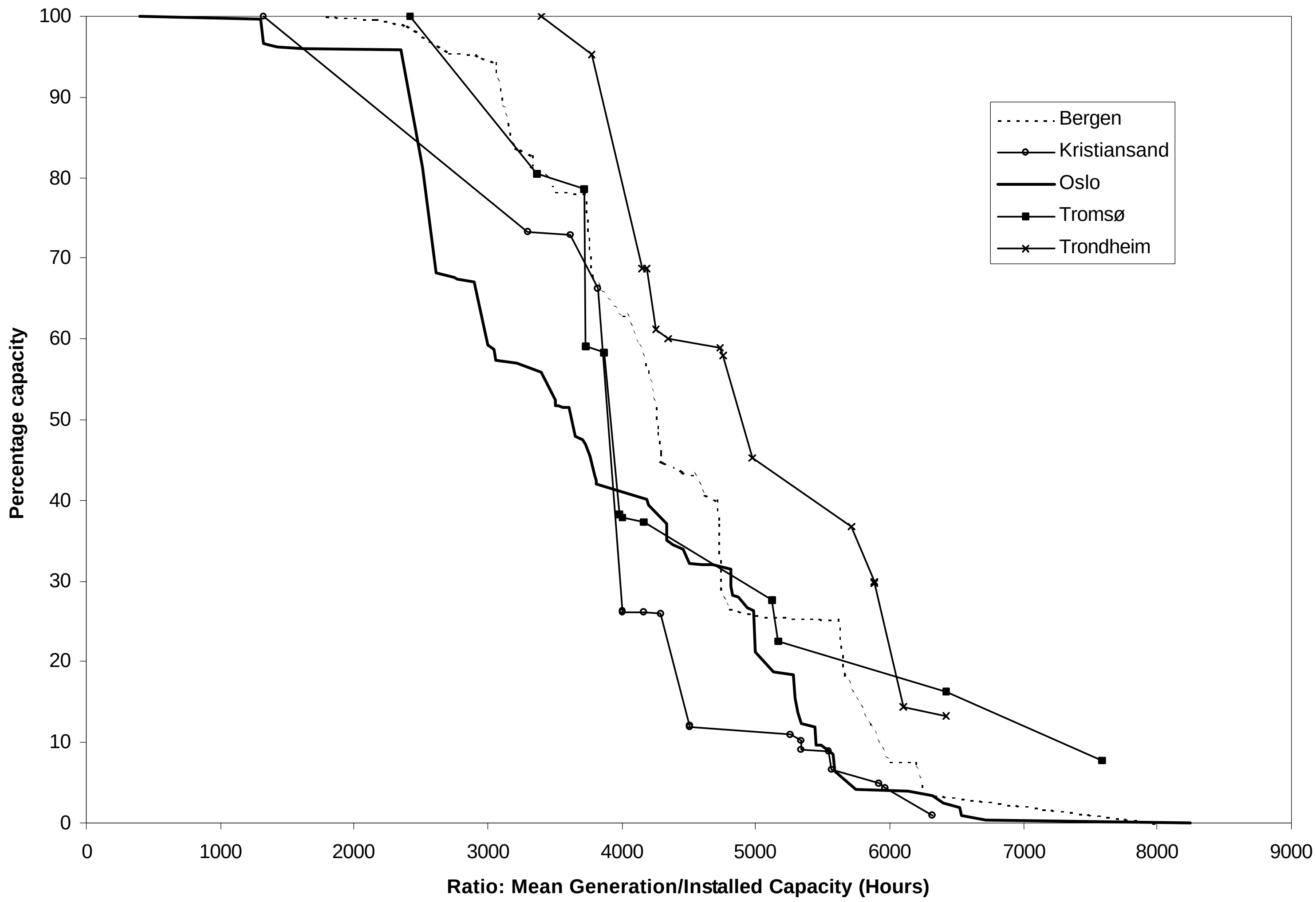
Table 3: Plant Characteristics

	Annual Inflow	Storage Capacity	Generation Capacity	Inflow/ Generation	Storage/0.87 × Generation
	GWh/year	GWh	MW	Hours	Hours
Oslo	33,516	17,594	6,340	5,286	3,190
Kristiansand	16,929	12,605	4,158	4,071	3,484
Bergen	33,689	26,707	9,399	3,584	3,266
Trondheim	22,617	18,445	5,245	4,312	4,042
Tromsø	9,323	8,565	2,231	4,179	4,413
Norway	116,074	83,916	27,373	4,240	3,524

Source: Hornnes (1995)
Note: The last column uses the multiplier 0.87 since that is the generation capacity expected to be available in the winter. Area definitions for Bergen and Oslo are different from other tables.

8 The model in Section 3 makes these points more formally.

Figure 3: Supply-Duration Curves



In Figure 3, we used data on annual mean generation and turbine capacity for a sample of plants. We plotted the percentage capacity within each area against the number of hours that they would be required to operate at full capacity in order to fulfil their mean generation.[9] The sample covers about 65 percent of the total capacity. The curves are analogous to load-duration curves. Trondheim seems to be the least flexible area. In Trondheim, 60 percent of the capacity has to be operated at full output for at least 5000 hours or more per year to exhaust the available water. Bergen and Tromsø are slightly more flexible, while Kristiansand and Oslo are the most flexible regions.

2.5 Storage, Generation, Price and Trade Patterns

The availability of water in the Norwegian power systems varies substantially from year to year. Snow volumes, summer temperatures (snow melting) and rainfall determine the inflow volume at different times in the year. Annual inflow varies between ± 25 percent of normal or average inflow. Changes in demand depend upon temperature which determines heating load, day-length which determines lighting needs and prices [Johnsen, 1999]. The inflow, demand and storage patterns are illustrated in Figure 4.

In the winter of 1998, weekly inflow varied from approximately 20 to 100 percent of the weekly generation, while in the summer inflow for some weeks was four times as large as the generation. Reservoirs reach their minimum in the end of the winter (week 17-19) and are at their highest level in the autumn/beginning of the winter (week 35-40). The geographical distribution of inflows may lead to regional cost differences. Public information on storage is available only for aggregated regions (see Figure 5). While the most pronounced patterns are the countrywide seasonal swings, storage in the northern areas of Tromsø and Trondheim are slightly more volatile than the more southern areas.

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[9] Plant specific data on storage is not available. We ignore minimum flow constraints here since we do not have information on how often these constraints are binding. Figure 3 provides a lower limit for the number of hours it would take to use the average annual inflow. In the absence of minimum flow constraints, the only upper limit would be due to storage constraints. With flow constraints, however, there may be an upper limit as well on the number of hours during which the plant will have to be emptied. We consider the effects of flow constraints in Section 3.

Figure 4: Aggregate Generation, Inflow and Storage, 1998

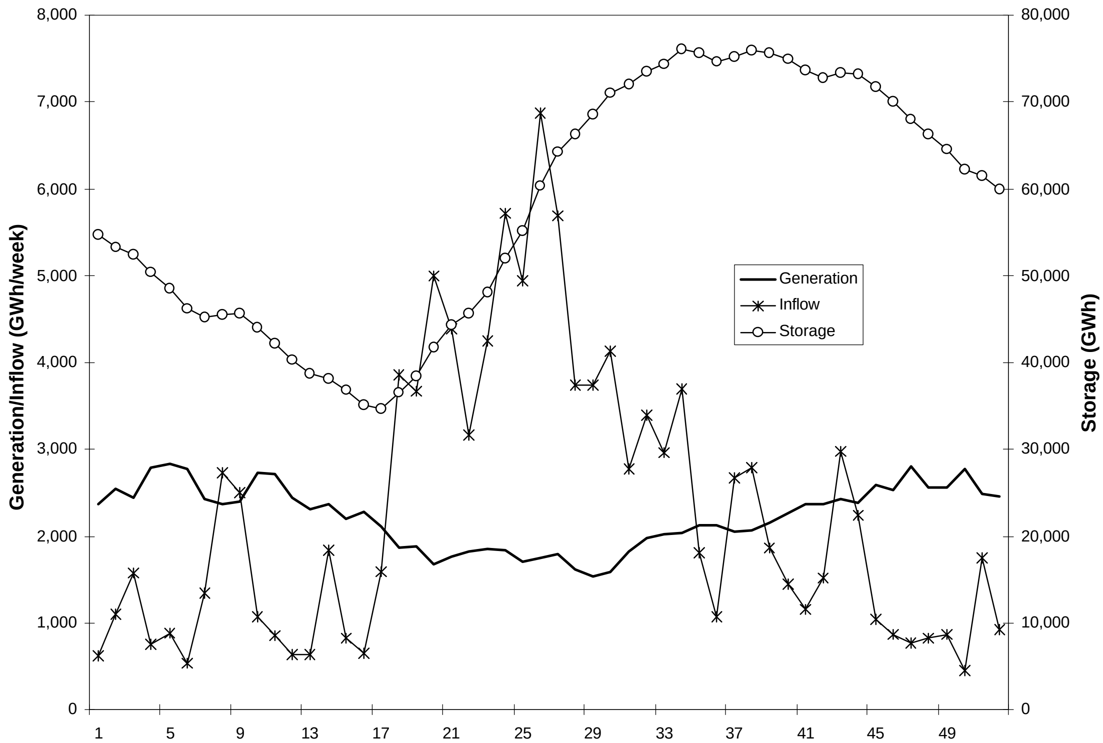


Figure 5: Percentage Reservoir Filling, 1995-1998

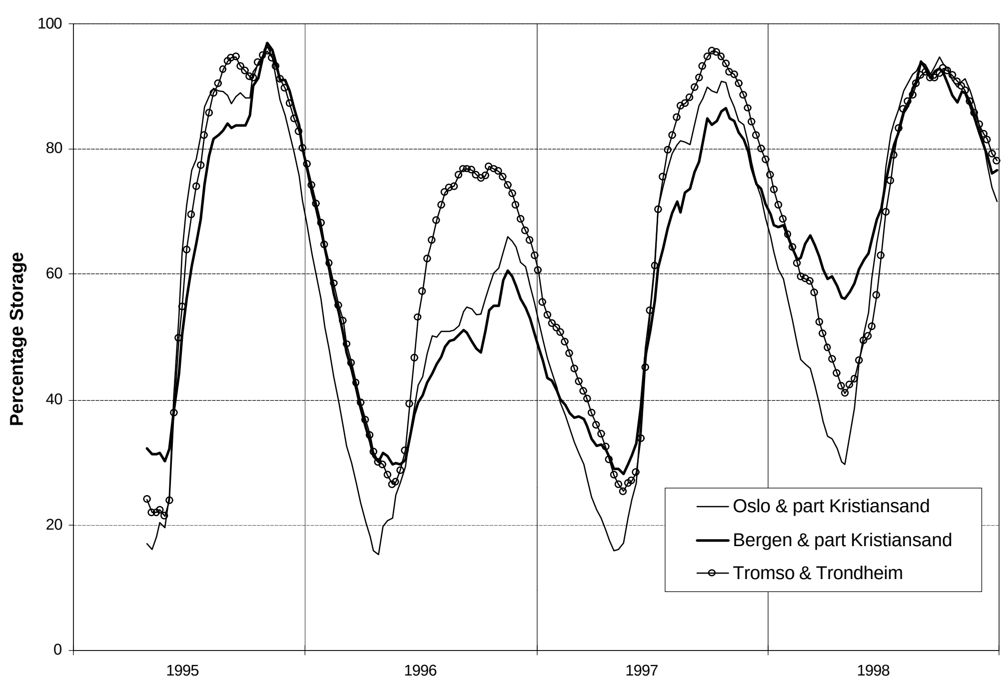


Figure 6: Mean Weekly Price in the Day-Ahead Market, 1993-1998

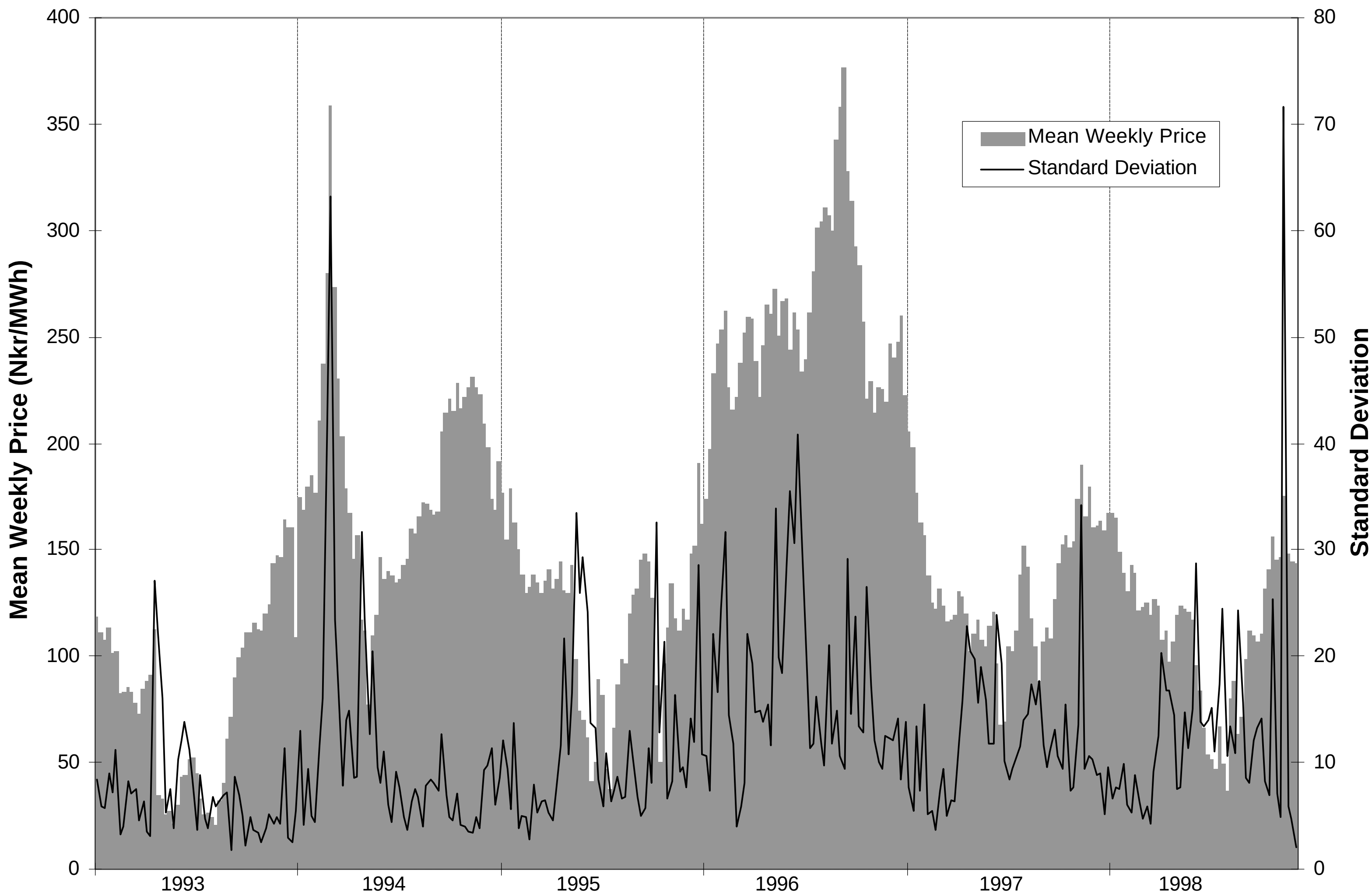


Figure 6 shows the mean weekly price in Oslo from 1995-1998. While 1995, 1997 and 1998 had more than normal inflow, 1996 was a dry year with considerably higher prices. Even during summer 1996, prices were high. Low volumes of snowmelt left little in the reservoirs and therefore diminished the likelihood of overflow. Except for the very dry year 1996, there is a clear seasonal pattern in the day-ahead prices and their volatility. During the winter generation mainly relies on withdrawal of water from reservoirs and prices are subject less to supply side shocks.

In addition to the seasonal patterns, there is also a daily cycle for prices, demand and supply. Figure 7 shows the average pattern of prices generation and consumption for 1996-98. There are two clear peaks at around 10 a.m. and 6 p.m. Weekend generation is lower and it varies less with a clear peak in the evening. The load pattern is similar, but the variation is less. The difference between generation and consumption shows the net exchange between Norway and other countries. Night and weekend prices are lower than weekday prices, due to the lower demand during those periods.

Figure 7: Pattern of Hourly Prices, Generation and Consumption, 1996-1998

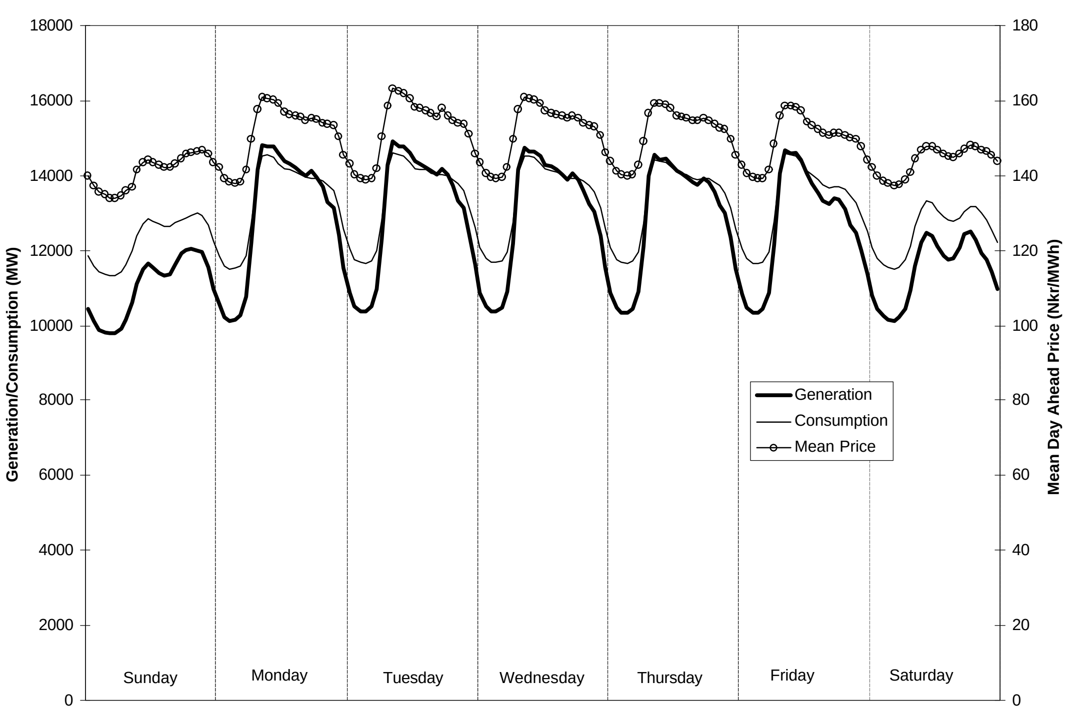


Figure 8: Pattern of Exchanges with Sweden, 1996-1998

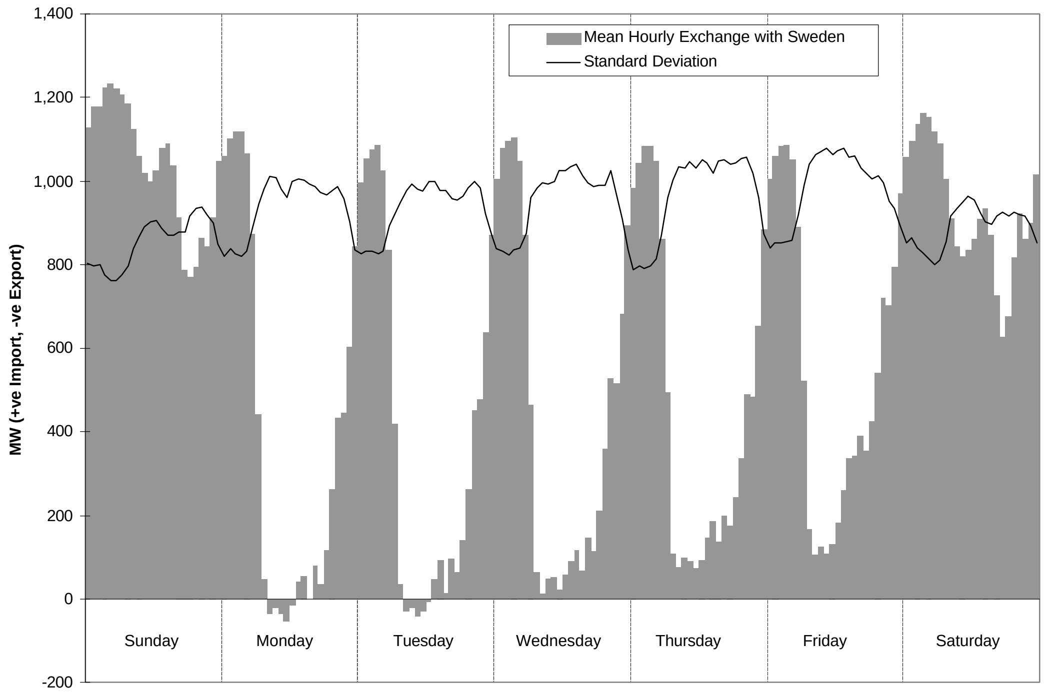
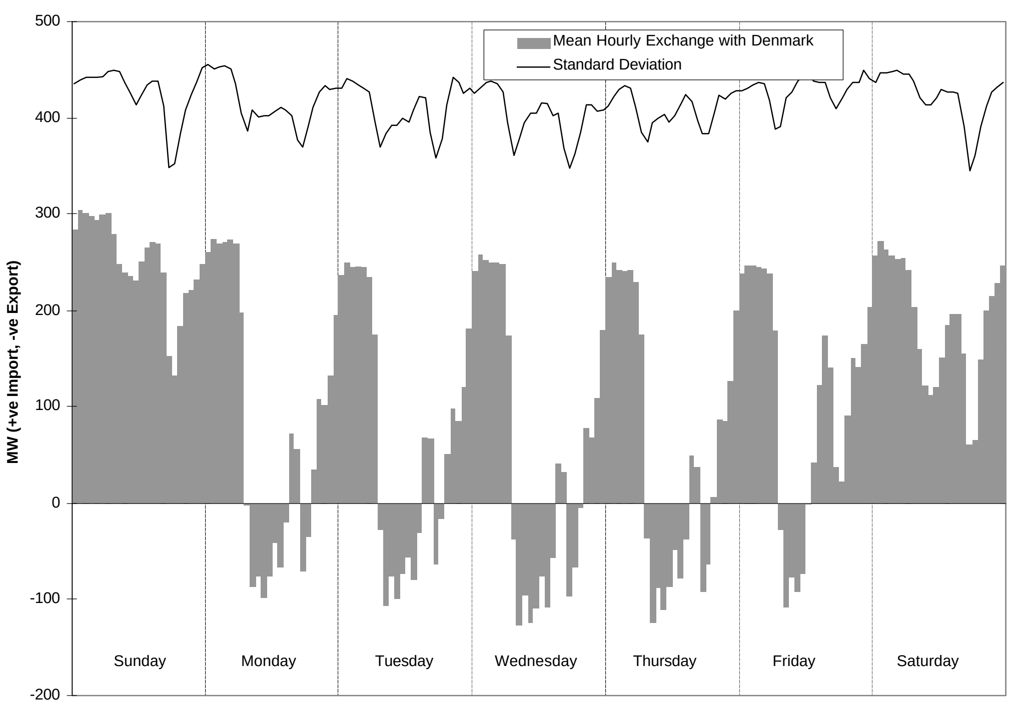


Figure 9: Pattern of Exchanges with Denmark, 1996-1998



Given the different mix of generating plants and different meteorological conditions between Norway, Sweden and Denmark there is significant trade in energy at different times of day and during different seasons. Sweden relies mainly on nuclear and hydropower with some peak oil or gas fired plants, while Denmark uses coal-fired thermal plants. Figures 8 and 9 show the profile of power exchange for Norway with Sweden and Denmark, respectively. In both cases, Norway is a net importer at night. It is less expensive to shutdown and re-start hydro plants than thermal plants, particularly nuclear, so Norway receives imports from its neighbors with more thermal capacity. There are small exchanges with Russia and Finland as well.

3. SUPPLY FUNCTIONS IN THE NORWEGIAN MARKET

In this section, we discuss costs at hydroelectric plants and then develop a simple model of a hydro market interconnected with a thermal system. We consider the hydro system both under perfectly competitive conditions and assuming some degree of market power.

3.1 Hydroelectric Costs

Hydroelectric plants generate electricity by converting kinetic energy from falling water. Unlike thermal plants, hydroelectric plants do not need to burn any fuel to generate electricity. Thus, hydroelectric generation has a very low variable cost of operation (typically less than 0.5 cents/kWh, compared with about 3 cents/kWh for gas or coal plants). However, hydroelectric plants typically require a large storage reservoir to regulate the flow of water between wet and dry seasons. The storage reservoir is created behind a dam on a river or stream. Once built, the dam cannot be easily altered and has a fixed storage volume. Stored water is drawn down during dry seasons in order to maintain higher generation than the unregulated stream flow would produce. As long as the storage volume is limited to less than the water required to satisfy demand during all periods, there is a constraint on the supply of *energy*. Thus, computing generation costs requires computing the shadow price of stored water.

Solving the generator's intertemporal profit maximization problem provides a shadow price for water, commonly known as water value [Read, 1979]. In a perfectly competitive market, each plant should simply bid a price for electricity that reflects its water value and the efficiency of its turbines. If the plant bids a price lower than the market price, it gets dispatched. If, on the other hand, the plant bids a price higher than the market price, it does not get dispatched and thus ends up with more storage at the end of the period. The higher storage level tends to lower the water value at the plant, thus bringing it in line with the rest of the market. In equilibrium each plant should have a water value equal to the market price. The engineering model that firms use to compute the shadow price of water in the Norwegian system uses the spatial decomposability property of the profit maximization problem to separate the operation of different plants, using the market price as the relevant state variable [Rotting and Gjelsvik, 1992].

In practice, the profit maximization problem for a hydroelectric plant is complicated by uncertainty about both demand and inflows. The plant operator should incorporate beliefs about market prices and inflows in all future periods. Unexpected changes in inflows and demand can change the water value specifically for the plant and generally for the system. However, with large storage, small changes in inflows do not drastically alter the water value. Thus, water values may be assumed to be constant over short periods of time, say within a week in systems with sufficient storage. The Norwegian system has a storage capacity equal to about 75 percent of its annual generation and, since a large part of the inflows are due to snow melt, inflows are relatively predictable, further reducing unexpected changes in water value (see Table 3).

It has been generally assumed that hydroelectric markets do not have market power. If firms seek to restrict quantity during a period, that would result in a greater end-of-period storage and thus lower water values in future periods. The only way to increase the water value would be to dispose of water by spilling it without generating electricity. Deliberate spilling of water, however, is directly observable and thus less likely to be used as a means of exercising market power. Less attention has been dedicated to the problem of market power in markets with transmission constraints [Førsund, 1998].

If generators are located in different areas, some transfer of energy between the regions will be necessary in order to balance the water values in the two regions when they diverge. The price should remain the same in the two regions for arbitrage reasons. However, if there is only a limited capacity to transmit power between the areas the arbitrage opportunities are limited by the capacity of transmission lines. With transmission constraints, firms may be able to temporarily restrict quantities in a smaller, more concentrated market when they get separated from other areas. Exporting electricity in other periods when transmission lines are not constrained can dissipate the resulting lower water values. Therefore, if the system has alternating constrained and unconstrained periods firms may be able to exercise significant market power. Such cycles may occur over the course of days or over seasons.

If transmission constraints are binding only intermittently, such as for some hours of the day, the water values in different areas should still even out. The resulting market prices should not be very different in the separate areas in such cases. If however, constraints are binding for prolonged periods, such as several weeks or entire seasons, water values may indeed be different in different areas, resulting in different prices.

3.2 Trade with Thermal Systems

To formalize a Norwegian generator's optimization problem, we develop a deterministic model of a hydropower generator who operates in a region that is linked to a large thermal power area through a transmission line. The model aims to provide insight into a plant operator's incentives to withhold capacity during periods of transmission constraints and how these incentives vary as a function of the plant's characteristics. We consider subsequent days. Each day consists of a day and a night-period. In the thermal power area there exist constant day and night prices of electricity, s_d and s_n, where $s_d > s_n$. The transmission capacity between the hydropower and thermal region is Y. Electricity demand in the hydropower area is given by a downward sloping demand curve:

$$D_i = D_i(P_i) \text{, i = d, n} \quad (1)$$

where P_i is the power price. Market equilibrium is given by

$$y_i + x_i = D_i \text{, i = d, n} \tag{2}$$

where x_i is hydropower generation and y_i is power import ($y_i > 0$) or export ($y_i < 0$).[10] The import and export is determined in the following way

$$\begin{aligned} y_i &= Y & if \quad P_i &> s_i \\ y_i &= D_i(s_i) - x_i & if \quad P_i &= s_i \text{, i = d, n} \\ y_i &= -Y & if \quad P_i &< s_i \end{aligned} \tag{3}$$

where s_i is the price in the thermal area. We first consider the operation of a price-taking generator, and then extend the analysis to allow for market power.

The hydropower generator manages a water reservoir. The water budget is

$$r_t \le r_{t-1} + I_t - x_t \tag{4}$$

where r_t is the storage level at the end of day t, I_t is the inflow throughout day t and x_t is the generation of day t. The inequality stems from the possibility of overflow. For day t, the generation is the sum of day and night generation, $x_t = x_d + x_n$. Several physical constraints limit the generation decision. Obviously there are upper and lower reservoir filling limits

$$0 \le r_t \le \overline{R} \tag{5}$$

where $\overline{R}$ is the maximum storage (more specifically, $\overline{R}$ and 0 are the maximum and minimum storage levels). In addition, the turbine capacity, $\overline{X}$ and minimum flow requirements, $\underline{X}$ may limit the actual production

$$x_i \le \overline{X} \text{, i = d, n} \tag{6}$$

$$x_i \ge \underline{X} \text{, i = d, n} \tag{7}$$

There may be a limit on the variation (V) in the generation

$$-V \le x_d - x_n \le V \tag{8}$$

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[10] We consider the range of prices where sufficient capacity is available to meet demand, so that an equilibrium in fact exists.

We neglect uncertainty and assume that a price taking hydropower generator maximizes

$$p = \sum_{t=1}^{T}(P_{dt}x_{dt} + P_{nt}x_{nt})$$

given the constraints (4) to (8). Prices across days and nights are driven by the prices in the neighboring thermal system(s) and the limits on imports. This is a Kuhn-Tucker problem, and the related Lagrange-equation is

$$\begin{aligned} L = &\sum_{t=1}^{T}(P_{dt}x_{dt} + P_{nt}x_{nt}) - \sum_{t=1}^{T} l_t(r_t - r_{t-1} - I_t + x_{dt} + x_{nt}) - \\ &\sum_{t=1}^{T} a_t(-r_t) - \sum_{t=1}^{T} b_t(x_{dt} - \overline{X}) - \sum_{t=1}^{T} d_t(x_{dt} - x_{nt} - V) - \sum_{t=1}^{T} m_t(\underline{X} - x_{nt}) \end{aligned} \tag{9}$$

We focus on the winter period when water is withdrawn from reservoirs, and therefore we have suppressed the upper reservoir level constraint. In order to simplify, we have assumed the day generation to exceed the night generation and dropped the lower limit in (8) and assumed (6) and (7) only hold during the day and night respectively. Differentiation of (9) with respect to x_{dt}, x_{nt} and r_t gives

$$P_{dt} = l_t + b_t + d_t \tag{10}$$

$$P_{nt} = l_t - d_t - m_t \tag{11}$$

$$l_t = l_{t+1} + a_t \tag{12}$$

<u>Lagrange Multipliers</u>

l_t	Storage constraint
α_t	Minimum storage constraint
b_t	Maximum generation constraint
m_t	Minimum generation (flow) constraint
d_t	Limits on variation in generation (ramp rates)

Interpretations

Let us assume that the reservoir is empty in period T and only in period T.[11] Then, $l_1 = ... = l_{T-2} = l_{T-1} = l_T = a_T$. We next rearrange equations (10) and (11) and solve for δ_t:

$$d_t = \frac{P_{dt} - P_{nt}}{2} - \frac{b_t + m_t}{2} \qquad (13)$$

d is the shadow value on the constraint on the variation in generation between night and day (V). Considering the scenarios under which this constraint is either binding or not provides insight on factors that determine how a generator's costs at night compare to daytime costs, and, hence what the slope of the cost function is over a day.

$\boldsymbol{d_t = 0}$ (suggesting that the shifting constraint is not binding and generator's output over a period will be relatively constant) if:

1. $P_{dt} = P_{nt}$ and $b_t = m_t = 0$. This is a special case, and simply suggests that, so long as prices are equal across the night and the day, the generator will not try to shift output between the night and the day.
2. $P_{dt} - P_{nt} = b_t > 0$ and $m_t = 0$. This corresponds to the case where the generator does not shift output to the day even though prices are higher because its turbine is too small relative to the reservoir capacity. It essentially needs to run at full capacity during the day and full capacity minus some $e<V$ during the night just to use up all its water.
3. $P_{dt} - p_{nt} = m_t > 0$ and $b_t = 0$. This is similar to the above situation, but the generator needs to run at some capacity less than $\overline{X}$ and greater than $\underline{X}$ during the night to use up its water.
4. $P_{dt} - P_{nt} = b_t + m_t$. This is a knife-edge case where the generator runs at full capacity during the day and at $\underline{X}$ at night and just uses up its water. Here $V \geq \overline{X}$ *-0*.

[11] If the reservoir is not emptied in period T, the water value is zero and the generator will produce at the turbine-capacity in all periods. Generators will not empty their reservoirs before period t so long as the prices across periods are constant ($P_{dt} = P_{ds}$, $P_{nt} = P_{ns}$) or at least, not declining too fast over time.

On the other hand, $d_t > 0$ to the extent $P_{dt} > P_{nt}$ and b_t and m_t are small or zero.

Generally, generators are more likely to have flat output across days and nights (*i.e.* be unconstrained by the limit on variation, V) if their generation capacity is small relative to their reservoir capacity. (Scenarios 2 and 4 above both obviously suggest small turbine capacities, while scenario 3 relies on a binding minimum flow constraint during the night). On the other hand, generators with small reservoirs relative to their turbines will be more likely to try to conserve water during the night in order to take advantage of the high daytime prices. Knowing something about the turbine capacities, reservoir sizes and limits on variation across generators within a given region provides insight on the extent to which output is likely to be lower during the night than the day. Generators with large turbines relative to their reservoirs face very low (possibly negative) marginal costs to generating during the night when prices are (exogenously) low (see Figure 3). Also note that the likelihood that scenario 1 is applicable is a function of the price levels, P_d and P_n.

3.3 Market Power

We next drop the assumption that the hydropower producers are price takers, although we continue to treat the prices in the thermal power region and the transmission capacity between the hydro and thermal areas as exogenous.[12] The same set of physical constraints applies. A monopolistic generator takes advantage of the relationship between price and demand and maximizes

$$p = \sum_{t=1}^{T}\left\{P\left(x_{dt} + y_{dt}\right)x_{dt} + P\left(x_{nt} + y_{nt}\right)x_{nt}\right\} \tag{14}$$

where $P(x_{it})$ is the inverse of the demand curve specified in equation (1). Note, however, that the inverse demand curve is not differentiable over its whole range. If we are on the

[12] Joskow and Tirole (1999) study various examples where the generators are able to obtain transmission rights and thereby control the transmission capacity. Their setup does not fit the Norwegian market in which the system operator controls the utilization of the transmission connections and collects the merchandizing surplus. Borenstein, Bushnell and Stoft's (1998) result, suggesting there may be an incentive to withhold capacity to induce a transmission constraint, may hold in Norway.

differentiable part of the curve (in other words, if import prices are sufficiently low), we can write the first order conditions of the Lagrangian with respect to x_{it} and r_t as:

$$P_{dt} = l_t + b_t + d_t - P'(x_{dt} + y_{dt})x_{dt} \tag{15}$$
$$P_{nt} = l_t - d_t - m_t - P'(x_{nt} + y_{nt})x_{nt} \tag{16}$$
$$l_t = l_{t+1} + a_t \tag{17}$$

Again, if we assume the constraints on turbine capacity (6), intra-day shifting (7) and night generation (8) are *not* binding then equation (15) and (16) dictate that the marginal income in the two periods are equal and equal to the water value (λ_t). Whether it still is reasonable to assume empty reservoirs at the end of the planning period is an open question. If the reservoirs are not empty the water value will be zero and the generator should increase output until the marginal income equals zero. Regardless of whether b, d, and m are non-zero, equations (15) and (16) summarize the pricing rule for a monopolistic generator in terms of its costs and the elasticity of demand.

4. Empirical Approach

This section describes the assumptions underlying our empirical approach to identifying market power. In order to represent the variation in prices, both from day to day and within day, we can rewrite the demand function in (1) as:

$$D_{jt} = D_j\left(P_{jt}, H_t, W_t, w_t, n_{Dt}, e_{Djt}\right) \tag{18}$$

where j indexes a transmission zone within which prices are uniform and t indexes the time period. H is a variable for the hour within a day and W a dummy variable that identifies whether the time period lies on a weekday or a weekend; w is the week during which the time period lies. Demand also depends upon unobservable factors n_D and e_{Dj}, which are shocks to demand common across all areas and idiosyncratic to area j, respectively. Similarly, zone-wide marginal costs can be written as

$$MC_{jt} = MC_j\left(D_{jt}, l_{jt}, b_{jt}, d_{jt}, m_{jt}, n_{Ct}, e_{Cjt}\right) \tag{19}$$

where l, b, d and m are the Lagrange multipliers from equations (10) and (11) and n_C and e_{Cj} are common and idiosyncratic shocks to marginal cost, respectively.[13] We can summarize the first order conditions presented in equations (15)-(16) with the following expression:

$$P_{jt} = MC_j(D_{jt}, \Lambda_{jt}, n_{Ct}, e_{Cjt}) + \frac{P_{jt}}{h(P_{jt}, H_t, W_t, w_t, n_{Dt}, e_{Djt})} q_{jt} \qquad (20)$$

where we have summarized the Lagrange multipliers as L_t. h represents the elasticity of industry demand (net of imports) and q summarizes the extent of market power in the industry. For instance, q = 0 corresponds to price taking while q = 1 corresponds to the monopoly pricing.

Our empirical work does not aim to estimate q. (See Bresnahan, 1989, Corts, 1998 and Wolfram, 1999 for more discussion of the interpretations of and issues identifying q.) We use it here to help distinguish two factors influencing a firm's incentives to push prices above marginal costs, those related to the competition in the market[14] and those related to the industry-level demand elasticity. Our empirical setting is particularly conducive to this distinction since there are exogenous factors that change the number of competitors a firm faces (transmission constraints) and separate factors that change the industry-level demand elasticity. For now, we will rewrite $q/h = f$ and re-arrange (20) to get a simple expression for the equilibrium markup of price over marginal cost:

$$P_{jt} = \frac{MC_{jt}(\cdot) n_t e_{jt}}{1 - f_{jt}} \qquad (21)$$

where we combine shocks to cost and demand and assume that the error terms are multiplicative. Taking logs this becomes:

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[13] Note that the stochastic nature of the problem solved to determine the water value is incorporated in the Lagrange multipliers rather than in the error terms. The error terms capture changes in costs that are outside the model, such as changes due to maintenance needs.

[14] For instance, in a symmetric Cournot model, the industry q is equal to one over the number of competitors in a market.

$$\ln(P_{jt}) = \ln(MC_{jt}(.)) - \ln(1 - f_{jt}) + n'_t + e'_{jt} \qquad (22)$$

where *n'* and *e'* are the logarithms of the error terms in equation (21).

We explain, first algebraically, then graphically, how re-writing the first order condition as equation (22) helps us identify market power. Assume that there are two areas, A and B. Area A is sometimes constrained from importing, at which point the residual demand curve faced by suppliers in Area A expands.[15] Consider two periods 1 and 2 during which *H*, *W*, and *w* are equal and assume that Area A is constrained from importing in period 2 and unconstrained in period 1. Taking the difference across periods, we get:

$$\begin{aligned} \ln(P_{A2}) - \ln(P_{A1}) = \ln(MC_{A2}) - \ln(MC_{A1}) - \ln(1 - f_{A2}) + \\ \ln(1 - f_{A1}) + n'_2 - n'_1 + e'_{A2} - e'_{A1} \end{aligned} \qquad (23a)$$

and

$$\begin{aligned} \ln(P_{B2}) - \ln(P_{B1}) = \ln(MC_{B2}) - \ln(MC_{B1}) - \ln(1 - f_{B2}) + \\ \ln(1 - f_{B1}) + n'_2 - n'_1 + e'_{A2} - e'_{A1} \end{aligned} \qquad (23b)$$

If we assume that $q_{B1} = q_{B2} = 0$ (in other words, that Area B is always competitive), then the *ln(1-f)* terms of equation (23b) drop off. To simplify notation, we will also assume for now that q_{A1} equals zero, suggesting that there is only market power in Area A when transmission constraints are binding. Subtracting equation (23b) from (23a), we get:

$$\left[\Delta \ln(P_A) - \Delta \ln(P_B)\right] = \left[\Delta \ln(MC_A) - \Delta \ln(MC_B)\right] - \ln(1 - f_A) + \Delta e'_A - \Delta e'_B \qquad (24)$$

Without information on marginal costs in both areas during both time periods, equation (24) cannot be used to identify market power. Instead, we identify periods across which we think (a) the *ln(1-f)* term on the right-hand side of equation (24) will vary but (b) any differences in marginal costs between areas A and B will be constant. For instance, on weekends and in the middle of the night, there is less demand side

[15] As we will explain in more detail below, we assume that Area A's constraint does not affect Area B.

bidding (i.e. the demand side is less elastic, so that $h_{A1Night} < h_{A1Day}$) then $ln(1\text{-}f_{ANight}) < ln(1\text{-}f_{ADay})$. Also, h may vary as the level of imports shifts demand. Finally, when system demand is very high, the effective number of suppliers decreases as many reach their capacity constraints, so the aggregate q may increase. We can assess the effects of those factors by measuring the price differences on the left-hand side of equation (24). Taking differences for equation (24) between day and night we get

$$\begin{aligned}
&[\Delta\ln(P_A)-\Delta\ln(P_B)]_{NIGHT}-[\Delta\ln(P_A)-\Delta\ln(P_B)]_{DAY} = \\
&\qquad [\Delta\ln(MC_A)-\Delta\ln(MC_B)]_{NIGHT}-[\Delta\ln(MC_A)-\Delta\ln(MC_B)]_{DAY} \\
&\qquad\quad -\ln(1-f_{A,NIGHT})+\ln(1-f_{A,DAY})+ \\
&\qquad\qquad [\Delta e'_A-\Delta e'_B]_{NIGHT}-[\Delta e'_A-\Delta e'_B]_{DAY}
\end{aligned} \tag{25}$$

Since we are unable to observe the marginal costs we assume some relationships between the marginal cost functions for each area. Specifically, we assume that

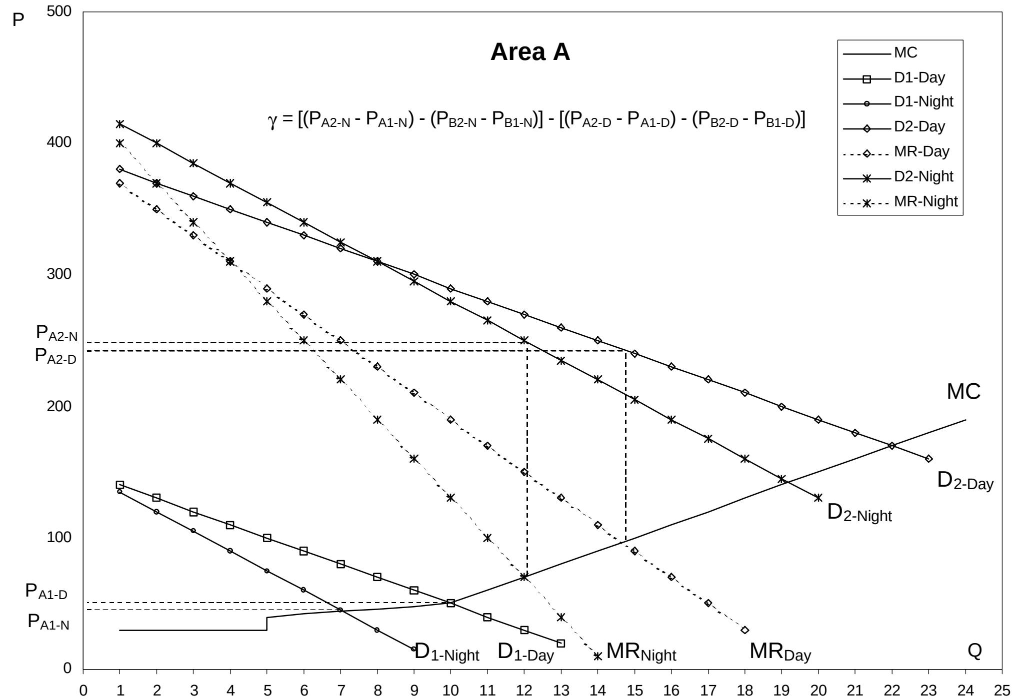
$$[\Delta\ln(MC_A)-\Delta\ln(MC_B)]_{NIGHT}-[\Delta\ln(MC_A)-\Delta\ln(MC_B)]_{DAY} \le 0 \tag{26}$$

In other words, we assume that if transmission constraints affect the difference between marginal costs in Area A and B, the effect is greater during the day than during the night. Later, we discuss the rationale behind this assumption and how violations of it may bias our results. If we assume that (26) holds with equality, we can rewrite equation (25) as

$$\begin{aligned}
g &= [\Delta\ln(P_A)-\Delta\ln(P_B)]_{NIGHT}-[\Delta\ln(P_A)-\Delta\ln(P_B)]_{DAY} = \\
&\qquad -\ln(1-f_{ANIGHT})+\ln(1-f_{ADAY})+\hat{e}
\end{aligned} \tag{27}$$

where $\hat{e}$ replaces the difference in the error terms. We expect g to be positive if the demand side constrains market power. g measures the extent to which firms use their market power to drive prices up when demand is less elastic.

Figure 10: Illustration of Market Power Result



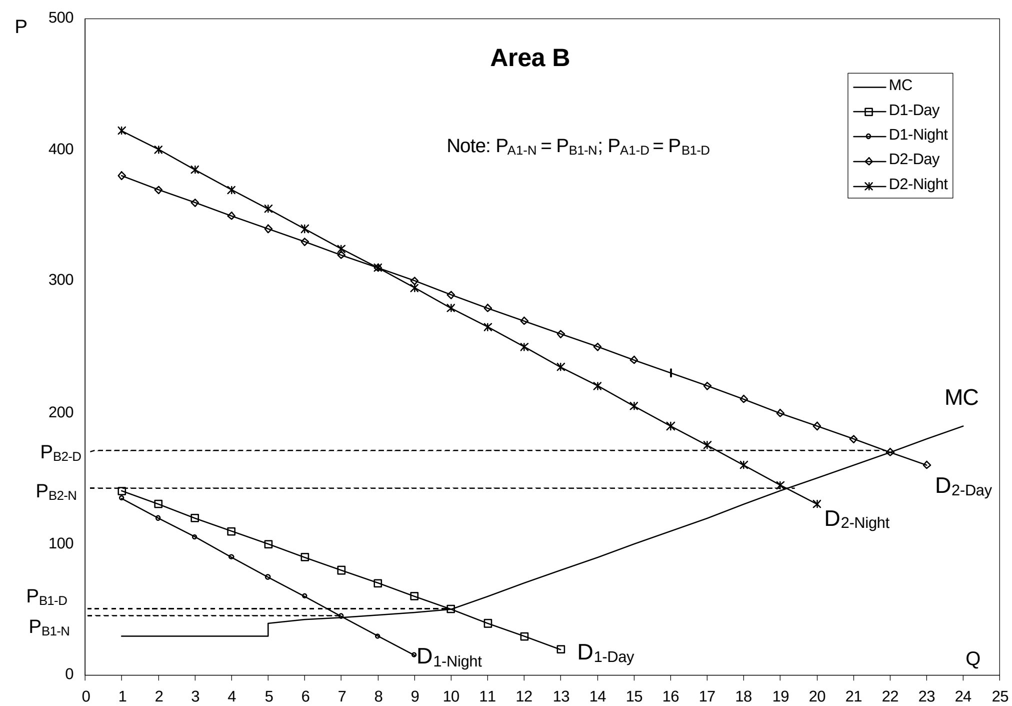


Figure 10 represents graphically the effect γ measures. Area A is depicted on the top and Area B on the bottom. The two areas are identical except that we assume there is market power in Area A when demand is high and transmission constraints bind. We assume that generators in both areas can provide 5 megawatts of power at low marginal cost (30 Nkr/MWh in the figure) but that any more generation from within each area has linear marginal costs with a slope of 10 beginning at 60 Nkr/MWh. Supply from outside the two areas can provide power with marginal costs increasing linearly with a slope of 2 beginning at 40 Nkr/MWh. However, there is only enough transmission capacity to bring 5 megawatts of power in from outside each area. When demand is low (D1-Day and D1-Night in the Figure), transmission constraints don't bind, and prices are competitive at 44 Nkr/MWh and 50 Nkr/MWh for day and night, respectively, in both areas. When demand is higher (D2-Day and D2-Night), then transmission constraints bind[16] and even though demand is lower at night than during the day over most quantities, equilibrium prices are slightly higher at night in Area A. Equilibrium prices (equal to marginal costs) are lower at night than during the day in Area B. Therefore, γ is positive.

Figure 10 simplifies a number of issues. First, we have been careful to draw roughly equivalent shifts between Day 1 and Day 2 and Night 1 and Night 2. Generally, the bigger the demand shock, the higher the prices will be, whether prices are competitive or not. If transmission constraints during the night were caused by larger demand shocks than shocks during the day, we would see bigger price differentials at night even if pricing were competitive.

One of the main roles of Area B is to control for the non-region-specific shifts (represented by ν_D in equation 18). The *price* in Area B controls for demand shocks so long as the slopes of the cost curves in the two areas are roughly comparable. If they are different yet the inequality in equation (26) holds, γ will, if anything, under-estimate market power. If the inequality in equation (26) is violated, however, we could estimate a positive γ even if there is competitive pricing. Choosing the appropriate control area is

[16] Bailey (1998), for instance, finds that transmission capacity is more likely to be congested during peak demand periods.

central to our analysis, and in the empirical section, we devote a fair amount of attention to assessing which areas have comparable marginal costs.[17]

Second, Figure 10 is drawn assuming that the transmission constraint is caused by a shock to demand. *Exogenous* shocks to supply will have effects symmetric to those depicted in Figure 10. For instance, a shock that removed the first 5 megawatts of power in both areas in Figure 10 could cause the transmission constraint to become binding. A supply shock could also be caused by a reduction of the capacity on a transmission line, for instance, while maintenance is done on it. The effects on pricing are identical to the effects of a reduction in local supply. Even if pricing is competitive, it is possible that negative supply shocks could lead to larger price increases at night. If demand is less elastic at night, prices may need to rise by more at night to equilibrate with the reduced supply.

We think this is unlikely to bias our results. First, to the extent the control area (Area B) is subject to the same supply shocks (for instance, the same water inflow rates), it will control for the competitive price changes (since we are assuming Area B is competitive). Transmission capacity reductions are likely to be local and so unlikely to affect a control area. Empirically, we can verify whether constraints are due to transmission capacity reductions.

We are also assuming that shocks to supply are exogenous to firm pricing behavior. In other words, we are assuming that there is no strategic congestion, no predatory pricing to drive out other firms, etc.[18]

Third, following the simplification we made before equation (24), Figure 10 is drawn assuming pricing in Area A is competitive when there are no transmission constraints. All our estimation strategy identifies is any increase in the exercise of market power brought on by transmission constraints. Similarly, both Figure 10 and the algebraic description of our estimation strategy assume that there is no market power in

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[17] It is also important that the relationship between the control area (Area B) and the test area (Area A) not be affected by the presence of a constraint. We discuss this further in the empirical section.

[18] Note that if firms are strategically inducing congestion (for instance, following the model in Borenstein et al., 1999), our estimation strategy underestimates the extent of market power.

Area B. If this is not true and there is market power in Area B, price changes in Area B ($Dln(P_B)$) will also reflect changes in demand elasticity between periods 1 and 2. So long as (a) the demand elasticity in Areas A and B move in similar directions across time periods, and (b) any changes in market power in Area B move in the same direction as changes in Area A, *g* will underestimate changes in price due to changes in the demand elasticity.

Since our estimation strategy relies on identifying periods across which demand elasticity varies, it is worth considering why demand is elastic. In most electricity markets, consumers are not allowed to participate directly in the price-setting process. While some consumers who buy electricity at the spot market price adjust their consumption in response to changes in the spot price, others who buy electricity at a fixed price through long-term contracts do not have any incentive to adjust their demand. Thus, demand is inelastic if a large amount of energy trades at fixed prices through long-term contracts.

When consumers are allowed to participate in the market, consumers with long term contracts can potentially offer their contracted quantities on the spot market if the spot price is high enough for them to reduce their consumption, or to switch to alternate sources of electricity. Thus, we would expect demand side bidding to mitigate market power by making more energy available on the spot market. Note that the level of imports also affects the level of residual demand (and, for most demand curves, the elasticity).

In most electricity systems, it is reasonable to assume that large industrial and commercial consumers are better able to adapt their demand to changes in spot price. Since industrial and commercial consumers tend to consume more energy during the day and also more during weekdays than during weekends, we would expect demand elasticity to be higher during the day than the night and during weekdays rather than weekends. Nord Pool employees suggested that demand is more elastic during periods of higher demand. We take advantage of this to identify market power across time periods when the demand elasticity varies.

5. DESCRIPTIVE STATISTICS

We obtained information on the hourly prices in the Elspot market off the Nord Pool ftp server.[19] We have hourly local prices for 27 separate areas, including 23 in Norway, plus prices for Stockholm in Sweden, Helsinki in Finland and Ålborg and Copenhagen in Denmark. For most of the areas, we have information only for 1998, and nine of the areas are identical to an adjacent area for the whole year. We also have information on the System Price, which reflects the price that would be charged system-wide if there were no transmission constraints.

Norway is divided into at most five zones at any given time, and at most eight different prices are set including Stockholm, Helsinki and Copenhagen.[20] Different price series are available for 18 separate areas because the boundaries of the price zones can change week-to-week. The bulk of our analysis focuses on five areas: Bergen, Kristiansand, Oslo, Trondheim and Tromsø, which correspond to the consumption centers of the most common zones. The difference between the System Price and prices in Bergen, Kristiansand, Oslo, Trondheim, Tromsø and the non-Norwegian locations are summarized in Table 4 by season and by day or night.[21]

Several patterns stand out. Generally, the price differences indicate whether areas have been net importers and have prices higher than the system price or net exporters with prices lower than the system price. As one would expect for trade between hydro and thermal systems, Stockholm is more likely to be import constrained during periods of high demand (winters and days) and export constrained during periods of low demand (summer and nights). Within Norway, Bergen and Kristiansand had higher prices during 1998, although Bergen seemed to have higher prices during the winter and Kristiansand in the summer. The standard deviations for most areas suggest that prices are more volatile during the summer. (This is confirmed if we look at changes by hour from the

[19] Subscription information is available from Nord Pool's website at www.nordpool.no.

[20] During 1998, the entire Nord Pool area was unconstrained for 43.8 percent of the hours. There were two price areas for 32.2 percent of the hours, three areas for 14.9 percent, four areas for 6.9 percent, five areas for 1.9 percent and six areas for 0.4 percent of the hours.

[21] The data in Table 4 and in all further analysis include only weekday hours for the period for which data for that area was available.

previous day. The standard deviation of price *changes* is higher in the summer than in the winter.)

Table 4: Prices by Area

Area	Data Available:	Average Price Difference (Price – System Price): Nkr/MWh			
		Winter	Summer	Day	Night
Bergen	1/93 – 12/98	2.62 (10.65)	.32 (9.32)	2.24 (8.89)	.84 (11.40)
Kristiansand	1/93 – 10/95 & 1/97 – 12/98	1.43 (4.32)	.76 (7.31)	.82 (5.79)	1.38 (5.94)
Oslo	1/93 – 12/98	1.14 (5.19)	.36 (6.92)	.07 (5.23)	1.41 (6.56)
Tromsø	1/95 – 12/98	-.50 (8.28)	-.91 (10.74)	-.37 (10.16)	-.94 (10.74)
Trondheim	1/96 – 12/98	-1.23 (8.60)	-4.29 (16.80)	-3.17 (13.48)	-2.07 (12.46)
Non Norway:					
Ålborg	5/98 – 12/98	-.27 (4.18)	1.75 (10.55)	.66 (7.85)	2.28 (8.99)
Helsinki	5/98 – 12/98	-5.35 (10.20)	9.48 (20.30)	9.13 (21.20)	-1.36 (14.05)
Stockholm	1/96 – 12/98	-1.08 (12.68)	-2.03 (12.05)	.56 (14.83)	-3.23 (9.58)
1998:					
Bergen		7.83	-2.34	2.01	4.60
Kristiansand		-.06	1.38	-.41	1.39
Oslo		-.06	-1.82	-2.10	.26
Tromsø		-1.17	.23	-1.55	.28
Trondheim		-1.05	-.88	-.2.51	.32
Stockholm		-2.44	.39	1.62	-3.61

Note: Standard deviations in parentheses. Winter is defined as weeks 41-17; summer as weeks 18-40. Night is defined as 7 p.m. to 7 a.m.

Table 5 shows the percentage of hours that each of the areas was either import or export constrained. The constraint is defined with respect to the area in the second column. For our analysis, import (export) constrained hours are defined as those during which the price in the area was higher (lower) by 0.1 Nkr/MWh compared to the adjoining area. For the most part, the percentage of constrained hours has been increasing over the years, with 1998 being more constrained than all previous years.

Table 5: Ratio of Constrained Hours to all Hours

	Constraint Area	N	Import Constrained		Export Constrained	
			All Day	Night	All Day	Night
1996-1998:						
Bergen	Oslo	24552	.064	.034	.023	.010
Kristiansand	Oslo	12500	.047	.022	0	0
Tromsø	Trondheim	18744	.056	.027	.045	.030
Trondheim	Oslo	18744	.087	.044	.220	.135
Trondheim	Tromsø	18744	.045	.030	.056	.027
1998:						
Bergen	Oslo	6360	.241	.130	.038	.016
Kristiansand	Oslo	6335	.053	.024	0	0
Tromsø	Trondheim	6360	.051	.023	.047	.026
Trondheim	Oslo	6360	.157	.086	.160	.100
Trondheim	Tromsø	6360	.047	.026	.051	.023

Note: Night is defined at 7 p.m. to 7 a.m. Constrained periods are identified as those in which the price difference is greater than 0.1 Nkr/MWh.

Table 6 reports correlations across different areas of the changes in the log price over the same hour on the previous day. The correlation between the study area and the area with respect to which constraints are defined changes substantially between unconstrained and constrained hours. This could reflect the fact that the constraint has opposite effects on the residual demand in each area. For instance, when Bergen is constrained from importing from Oslo, Oslo is also constrained from exporting to Bergen. The price in Bergen may rise as the price in Oslo falls. In order to better control for exogenous demand or supply shocks we define control areas, and we expect the correlation between price changes in the test and control areas to be less affected by the presence of the constraint. Comparing the first three columns of Table 6 to the middle three, that pattern holds for the control areas we have chosen. The last three columns report correlations with the System Price. They are also less affected by the presence of a constraint than the figures in the first three columns.

Prices in hydroelectric systems are derived from the shadow price of water, which does not change substantially over short periods of time. Therefore, we would expect prices in the Norwegian market to be serially correlated. Table 7 shows the adjusted R-squared values for lag one regressions of the log price during each hour for each area on the same hour in the previous weekday. The results are separately tabulated by whether the current hour was unconstrained, import constrained or export constrained and by whether the same hour on the previous day was unconstrained or constrained. R-squared values are quite high, showing that the previous day's price is a good predictor of the current price. Interestingly, the R-squared values decrease during constrained hours for most areas, showing that there may be other factors that determine the price during constrained hours. Also, across areas, the R-squared values are lowest in Kristiansand, especially during constrained periods.[22]

[22] Similar regressions on data from the PJM pool yielded adjusted R-squared values of 0.475. Wolak [1999] reports results of regressions used to predict prices in four pools; the values are much higher for hydroelectric systems than for thermal systems.

Table 6: Correlation between Price Changes in Different Areas

	Constraint Area				Control Area				System Price		
	Area	Uncon-strained	Export Constrained	Import Constrained	Area	Uncon-strained	Export Constrained	Import Constrained	Uncon-strained	Export Constrained	Import Constrained
Bergen	Oslo	.917 (22415)	.569 (557)	.168 (1580)	Tromsø	.644 (22415)	.526 (557)	.577 (1580)	.837 (22415)	.749 (557)	.602 (1580)
Kristiansand	Oslo	.915 (11907)	No Obs.	.189 (593)	Tromsø	.568 (11907)	No Obs.	.307 (593)	.801 (11,907)	No Obs.	.615 (593)
Tromsø	Trondheim	.964 (16860)	.574 (840)	.122 (1044)	Kristiansand	.547 (10863)	.244 (621)	.245 (1044)	.804 (16860)	.572 (840)	.591 (1044)
Trondheim	Oslo	.734 (12990)	.161 (4128)	.461 (1626)	Kristiansand	.634 (8509)	.122 (2891)	.539 (1128)	.849 (12990)	.497 (4123)	.612 (1626)
Trondheim	Tromsø	.964 (16860)	.122 (1044)	.574 (840)	Kristiansand	.528 (10863)	.099 (1044)	.265 (621)	.788 (16860)	.343 (1044)	.382 (840)

Note: Correlation coefficients are between the log price changes *Dln(Price$_{jt}$)* used in the regression equations. Number of observations in each category in parentheses. Constrained periods are identified as those in which price difference is greater than 0.1 Nkr/MWh.

Table 7: Adjusted R-Squared for Lag One Regressions on Log Price

		Unconstrained				Import Constrained				Export Constrained			
		Previous Day Unconstrained		Previous Day Constrained		Previous Day Unconstrained		Previous Day Constrained		Previous Day Unconstrained		Previous Day Constrained	
	Constraint Area	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night	Day	Night
Bergen	Oslo	.973 (9854)	.971 (11912)	.989 (333)	.973 (292)	.976 (235)	.978 (195)	.816 (511)	.870 (639)	.869 (98)	.870 (97)	.915 (211)	.882 (151)
Kristiansand	Oslo	.929 (5296)	.924 (6359)	.884 (103)	891 (125)	.905 (106)	.740 (121)	.595 (210)	.902 (156)	No Obs.	No Obs.	No Obs.	No Obs.
Tromsø	Trondheim	.962 (7570)	.956 (8776)	.990 (203)	.950 (287)	.975 (85)	.988 (78)	.916 (414)	.934 (410)	.997 (118)	.960 (209)	.996 (138)	.969 (333)
Trondheim	Oslo	.974 (5485)	.977 (5997)	.989 (683)	.961 (801)	.972 (225)	.973 (236)	.986 (512)	.973 (493)	.974 (463)	.969 (577)	.969 (1079)	.952 (1854)
Trondheim	Tromsø	.962 (7570)	.956 (8776)	.989 (203)	.945 (287)	.994 (139)	.990 (230)	.996 (138)	.990 (333)	.963 (116)	.980 (104)	.860 (414)	.789 (410)

Note: Constrained periods are identified as those in which price difference is greater than 0.1 Nkr/MWh. Night is defined as 7.pm. to 7 a.m. Number of observations in each category in parentheses. Numbers of observations in each category do not sum up to the total number of observations since periods of import constraints and previous export constraints and vice versa are ignored.

6. RESULTS

Using the price data summarized in Table 4, we derive estimates of γ (defined in equation 27) by estimating the following equation:

$$\begin{aligned}\Delta \ln(P_{At}) = X_t j \; &+ x\Delta \ln(P_{Bt}) + z_I ImportCon_t + z_E ExportCon_t + s\,Night \\ &+ g_I ImportCon_t * Night + g_E ExportCon_t * Night \\ &+ z_{I-1} ImportCon_{t-1} + z_{E-1} ExportCon_{t-1} + g_{I-1} ImportCon_{t-1} * Night \\ &+ g_{E-1} ExportCon_{t-1} * Night + e'_t \end{aligned} \qquad (28)$$

where *t* indexes a particular hour on a particular day. $\Delta\ln(P_t)$ captures the change in the log price over the same period 24-hours previously. ($\Delta\ln(P_t)$ for Mondays reflect price changes over the previous Friday.) $\Delta\ln(P_{At})$ represent the price changes in the area for which we are testing market power ("Area A" in the notation of section 4), and $\Delta\ln(P_{Bt})$are price change for the control area. *ImportCon* and *ExportCon* are dummy variables equal to one when area A is constrained from importing and exporting, respectively. *Night* is a dummy variable equal to one for 7 p.m. to 7 a.m. when we expect the demand side to be less active. We expect the coefficients on the interaction terms, γ_I and $\gamma_{E,}$ to be positive if there is market power. We use the index *t-1* on the last four variables to indicate the same hour on the previous day. These are included so that the coefficients on the contemporaneous variables ($ImportCon_t$, $ExportCon_t$ and their interactions with $Night_t$) pick up the effect of the step increase in moving from an unconstrained to a constrained period.[23]

In accordance with our assumptions about the demand function, we also estimate a series of dummy variables to control for the specific week (e.g., week 17 of 1995). These are the components of X_{it}.

[23] We have experimented with versions of this equation where we interacted the price changes in the control area with *Night*, *ImportCon*, *ExportCon*, and their interactions. The results are very similar to the ones we report.

In order to obtain consistent estimates of γ, it is essential that we pick an appropriate control area. We use several controls in the regressions we report below, and it is worth reviewing the general properties of different types of controls.

1. Adjacent areas within Norway. In some ways, these are the most natural. Since marginal costs are likely to vary in an area because of changes in the stochastic inflow of water, adjacent areas are most likely to experience similar weather patterns so that melting and rainfall will be the same. However, it is likely that when Area A is constrained from importing, Area B is constrained from exporting. (Note, however, that the impact this would have on prices wouldn't necessarily vary by day versus night.) Also, as suggested by the model presented in Section 3 the slope of the marginal cost curve in an area is a function of the flexibility of the plants, and these may not be similar across adjacent areas.

2. Non-adjacent areas within Norway. Considering non-adjacent areas overrides the endogeneity problem described above. However, more distant areas are likely to have less correlation in demand and supply conditions.

3. System Price. To the extent the System Price is constructed assuming there are no transmission constraints, it is a useful control for system-wide supply and demand conditions. However, since the thermal capacity in Sweden is frequently marginal, the System Price tends to be lower during the night because inexpensive thermal plants are marginal when demand is low. When there are no constraints, the price in all areas is equal to the System Price. When there are constraints, however, prices in the hydro-dominated Norwegian regions, if they are equal to costs, will be flatter between days and nights. For those reasons, using the System Price can bias our results in favor of finding market power. (If we define constraints with respect to the System Price, this would surely be the case.)

4. No control price. Marginal costs in hydroelectric systems only change as new information is acquired about expected reservoir levels or system prices. Over the very short-run, therefore, they should be stable. If the slope of the cost curves were constant across regions, therefore, we could obtain consistent estimates of γ as long as

we included dummy variables for short time periods so that the coefficients are identified off changes within those time periods. However, since the slopes of the cost curves vary by region, the difference between the costs of suppliers in one region and the system average costs (i.e., between the local price and the system price in unconstrained times) could vary as a function of the level of demand even in the absence of market power.

Results of estimating versions of equation (28) are reported in Tables 8 and 9. Table 8 reports the full set of coefficient estimates for Kristiansand, the area where there was consistent evidence of market power.[24] Table 9 reports the coefficients γ_I and γ_E for the other areas. (We do not report results for Oslo because radial lines connect it to three areas within Norway and to Sweden, so defining constraints become tricky.)

In Table 8, Kristiansand was defined as constrained when prices were different from the Oslo prices. Kristiansand is connected to both Oslo and Bergen, although the capacity of the line to Oslo is much larger than the line to Bergen (see Figure 1). The specifications in Table 8 were estimated using Oslo, Tromsø and the System Price as the control area. Each triple of columns estimates the specification on a different subset of the data, and the first of the three columns reports results using Oslo as the control area while the second and third columns report results using Tromsø and the System Price, respectively. Oslo fits the above description of an adjacent area, while Tromsø is not adjacent. Note that the correlation coefficients in Table 6 suggest that prices in Kristiansand and Oslo are much more correlated than prices in Kristiansand and Tromsø. According to Figure 3, however, the generators in Kristiansand and Tromsø face similar cost curves.

[24] The specifications reported in Table 8 also include the variable *DExchange*, which measures the net exchange between Norway and Denmark. Exchange between Denmark and Norway (via the Kristiansand area) may be unconstrained even when constraints between Kristiansand and Oslo bind, so we wanted to control for any influence trade with Denmark would have on the Kristiansand price. The other coefficients in Table 8 are almost identical if this variable is omitted.

Table 8: Prices in Kristiansand during Constrained and Unconstrained Periods

Dependent Variable: $\Delta \ln(\textit{Kristiansand Price}_t)$

Constraints Defined with respect to Oslo

	Ia	Ib	Ic	IIa	IIb	IIc	IIIa	IIIb	IIIc	IVa	IVb	IVc
Area B =	**Oslo**	**Tromsø**	**System Price**	**Oslo 1997**	**Tromsø 1997**	**System Price 1997**	**Oslo 1998**	**Tromsø 1998**	**System Price 1998**	**Oslo Summer**	**Tromsø Summer**	**System Price Summer**
Dln(Price(AreaB)$_t$)	.808 (.112)	.449 (.071)	.839 (.042)	.948 (.047)	.437 (.087)	.830 (.052)	.742 (.153)	.453 (.110)	.836 (.060)	.760 (.133)	.378 (.074)	.802 (.051)
DExchange$_t$	-.008 (.008)	-.022 (.016)	-.007 (.007)	-.001 (.002)	-.034 (.010)	-.014 (.005)	-.003 (.023)	-.001 (.035)	.005 (.016)	-.026 (.017)	-.068 (.027)	-.023 (.017)
Night	-.001 (.001)	-.000 (.002)	.000 (.001)	.001 (.001)	.001 (.002)	.001 (.001)	-.003 (.002)	-.001 (.004)	-.001 (.002)	-.003 (.003)	-.000 (.005)	.001 (.003)
ImportCon$_t$	.134 (.027)	.134 (.042)	.091 (.026)	.140 (.028)	.125 (.035)	.106 (.024)	.122 (.041)	.134 (.068)	.076 (.039)	.135 (.027)	.138 (.041)	.094 (.026)
*ImportCon$_t$*Night*	.157 (.061)	.181 (.066)	.165 (.057)	.072 (.073)	.082 (.076)	.083 (.069)	.226 (.078)	.256 (.083)	.226 (.074)	.159 (.061)	.181 (.067)	.165 (.057)
ImportCon$_{t-1}$	-.193 (.046)	-.128 (.048)	-.096 (.033)	-.100 (.062)	-.072 (.061)	-.066 (.050)	-.241 (.055)	-.158 (.066)	-.111 (.042)	-.190 (.044)	-.129 (.048)	-.097 (.034)
*ImportCon$_{t-1}$*Night*	-.112 (.050)	-.132 (.055)	-.140 (.046)	-.105 (.102)	-.098 (.093)	-.105 (.087)	-.126 (.045)	-.157 (.060)	-.165 (.042)	-.111 (.050)	-.128 (.056)	-.139 (.047)
Adjusted R-squared	.701	.428	.671	.841	.463	.765	.664	.427	.634	.652	.388	.622
N	12500	12500	12500	6165	6165	6165	6335	6335	6335	5452	5452	5452

Note: Standard errors in parentheses adjust for the presence of heteroskedasticity and serial correlation within a week. All specifications include week fixed effects. Constrained periods are identified as those in which the price difference is greater than 0.1 Nkr/MWh. Night is defined as 7 p.m. to 7 a.m. Summer is defined as weeks 18-40; winter as weeks 41-17. There were no constraints between Oslo and Kristiansand during the winter. *DExchange$_t$* is the change in physical exchange, in thousands of megawatts between Norway and Denmark on consecutive days during the same hour (*DExchange$_t$>0* implies more import, or less export).

Table 9: Estimates of g by Area

	Ia	**Ib**	**Ic**	**IIa**	**IIb**	**IIc**	**IIIa**	**IIIb**	**IIIc**	**IVa**	**IVb**	**IVc**
Area B =	Constraint Area	Non-adjoining Area	System Price	Constraint Area 1998	Non-Adjoining 1998	System Price 1998	Constraint Area Summer	Non-Adjoining Summer	System Price Summer	Constraint Area Winter	Non-Adjoining Winter	System Price Winter
Bergen: g_I	.004	.035	-.002	.026	.036	.016	-.014	.037	-.001	-.018	-.008	-.017
	(.022)	(.030)	(.019)	(.025)	(.026)	(.020)	(.034)	(.053)	(.040)	(.009)	(.009)	(.009)
g_E	-.003	.019	.014	.104	.193	.153	.042	.094	.063	-.056	-.051	-.053
	(.022)	(.025)	(.027)	(.079)	(.036)	(.066)	(.020)	(.019)	(.018)	(.028)	(.027)	(.035)
Adj. R^2 (N)	.710	.472	.700	.435	.317	.445	.771	.478	.721	.649	.498	.685
	(24552)	(24552)	(24552)	(6360)	(6360)	(6360)	(10992)	(10992)	(10992)	(13560)	(13560)	(13560)
Tromsø: g_I	.023	.032	.045	-.054	.079	.042	.014	.013	.036	-.020	-.027	.019
	(.052)	(.022)	(.019)	(.093)	(.053)	(.042)	(.054)	(.028)	(.020)	(.046)	(.019)	(.015)
g_E	-.086	-.102	-.065	-.151	-.135	-.134	-.140	-.213	-.111	-.020	.001	.001
	(.023)	(.052)	(.023)	(.060)	(.087)	(.062)	(.054)	(.081)	(.035)	(.019)	(.015)	(.011)
Adj. R^2 (N)	.679	.301	.635	.820	.270	.537	.671	.265	.592	.798	.826	.810
	(18744)	(12528)	(18744)	(6360)	(6360)	(6360)	(8232)	(5472)	(8232)	(10512)	(7056)	(10512)
Trondheim-Oslo: g_I	-.029	-.007	.003	-.024	.007	.013	-.015	.038	.021	-.035	-.023	-.026
	(.017)	(.024)	(.015)	(.021)	(.026)	(.021)	(.021)	(.029)	(.020)	(.020)	(.013)	(.018)
g_E	-.014	-.007	-.007	.024	.032	.012	-.031	-.006	-.024	.010	.005	.014
	(.015)	(.024)	(.012)	(.029)	(.036)	(.023)	(.025)	(.042)	(.020)	(.011)	(.009)	(.011)
Adj. R^2 (N)	.392	.338	.546	.425	.385	.578	.363	.333	.519	.654	.673	.706
	(18744)	(12528)	(18744)	(6360)	(6360)	(6360)	(8232)	(5472)	(8232)	(10512)	(7056)	(10512)
Trondheim-Tromsø g_I	.082	-.008	.023	.145	.019	.022	.118	-.039	.019	.027	.016	.027
	(.020)	(.043)	(.022)	(.062)	(.086)	(.062)	(.030)	(.084)	(.040)	(.017)	(.011)	(.013)
g_E	-.022	.008	.020	.079	.149	.113	-.014	.006	.021	.006	-.018	.026
	(.074)	(.078)	(.069)	(.114)	(.116)	(.116)	(.080)	(.089)	(.074)	(.063)	(.081)	(.074)
Adj. R^2 (N)	.685	.271	.510	.825	.312	.530	.661	.227	.472	.804	.655	.677
	(18744)	(12528)	(18744)	(6360)	(6360)	(6360)	(8232)	(5472)	(8232)	(10512)	(7056)	(10512)

Note: This table reports the coefficients on $ImportCon_t$**Night* and $ExportCon_t$**Night* for Bergen, Trondheim and Tromsø from estimates of equation (28). Bergen's constraint is defined with respect to Oslo, Tromsø's with respect to Trondheim, Trondheim's with respect to both Oslo and Tromsø. The "Non-adjoining" areas are as follows: Tromsø for Bergen, Kristiansand for Tromsø and Kristiansand for Trondheim. Standard errors in parentheses adjust for the presence of heteroskedasticity and serial correlation within a week. Constrained periods are identified as those in which the price difference is greater than 0.1 Nkr/MWh. Night is defined as 7 p.m. to 7 a.m. Summer is defined as weeks 18-40; winter as weeks 41-17.

There is some evidence consistent with the endogeneity explanation, since the coefficients on *ImportCon* are larger when either Oslo or Tromsø prices are used as the control (a and b columns) compared to the coefficients when the System Price is the control (c columns). The fact, however, that the coefficients on *ImportCon* are similar when both Oslo and Tromsø are used suggests that the fact that Oslo is adjacent to Kristiansand does not impact the endogeneity effect. The marginal capacity constrained from exporting from Oslo or Tromsø does not seem to vary between daytime and night, since the coefficient γ does not vary systematically between columns a, b and c. Generally, γ is higher when we use Tromsø as a control, suggesting that using a control area with a similarly shaped cost curve reduces the bias in γ as a measure of market power.

The coefficients on γ in Table 8 are generally positive and significant, suggesting that the suppliers within Kristiansand are consistently marking up prices more when demand elasticity is low and constraints are binding. The results are strongest during 1998, either suggesting that there was learning on the part of the generators, or perhaps suggesting that the assumptions underlying the specifications have changed over time. The coefficient estimates suggest that prices are at least 15 percent higher during the night than they would be if either there were no market power or if demand were more elastic at night. Recall that γ is identified by price increases due to congestion at night, given price increases during the day. Any market power that causes prices to be higher either when constraints hold during the day or when the system is unconstrained are not captured by γ.

Table 9 reports results for Bergen, Tromsø and Trondheim for several time periods using several different sets of controls. For most of the specifications and most of the areas, the coefficients are precisely estimated to be zero, suggesting that the generators are not increasing prices more when demand is less elastic and transmission constraints bind. The coefficient on *ExportCon*Night* is significant and negative for Tromsø and significant and positive for Bergen in 1998. The Tromsø coefficient is primarily driven by observations during the summer and may reflect higher unregulated inflows in Tromsø during the summer relative to the control areas. The Bergen coefficient may suggest that there was more market power in Bergen in 1998.

In Table 10, we allow the coefficients on *ImportCon*Night* and *ExportCon*Night* to vary by load level in order to test the hypothesis that the elasticity of supply varies as competitors become capacity constrained. We estimate γ_I and γ_E over periods during which consumption in all of Norway (load net of imports or exports) was in the first 25th percentile, in the 25th to 50th, 50th to 90th and 90th to 100th percentiles. The percentiles are calculated separately for each season, for example, winter 1997 or summer 1997. The primary pattern of interest in the table is the increase in the coefficient at higher load levels for Kristiansand. That pattern is consistent with the theory that the large generators in Kristiansand are better able to exercise market power at higher load levels, when the capacity of other competitors has been exhausted.

To the extent we can identify other instances where the elasticity systematically changes across periods, we can apply the same methodology embodied in equation (28). Two such possibilities clearly exist – comparing weekday prices to weekend prices and comparing prices across seasons. We generated results similar to those in Tables 8 and 9 by comparing weekend and weekday prices. Instead of using the difference in prices from the same period across consecutive days for the dependent and control area variables, we took long differences by day of the week. (For instance, Monday at 5PM minus previous Monday at 5PM.) Perhaps because marginal costs change more over a week, the results were less precise. Generally, the signs and sizes of the coefficients on the interaction between the constraint dummies and the weekend dummy were similar to the γ coefficients in Tables 8 and 9. Comparing prices across longer periods is even more imprecise since it requires controlling for marginal costs across seasons.

Table 10: Estimates of g by Load Level

Area:	**Fana**		**Kristiansand**		**Tromso**		**Trondheim-Oslo**		**Trondheim-Tromso**	
	Coefficient	N	Coefficient	N	Coefficient	N	Coefficient	N	Coefficient	N
g_{I-25}	.121 (.053)	299	.115 (.089)	116	.085 (.041)	154	.019 (.032)	362	.102 (.034)	328
g_{I-50}	-.028 (.057)	303	.140 (.064)	87	-.010 (.015)	125	.003 (.025)	139	.002 (.024)	174
g_{I-90}	-.007 (.031)	200	.250 (.083)	61	.011 (.017)	176	-.033 (.016)	69	.036 (.026)	59
g_{I-100}	.014 (.027)	31	.366 (.297)	13	.086 (.039)	59	.003 (.037)	2	-.022 (.236)	2
g_{E-25}	-	16	-	0	-.050 (.047)	328	.015 (.031)	958	.039 (.060)	154
g_{E-50}	.021 (.051)	31	-	0	-.045 (.019)	174	.073 (.035)	485	-.011 (.099)	125
g_{E-90}	.071 (.034)	71	-	0	-.091 (.056)	59	-.006 (.053)	421	-.050 (.150)	176
g_{E-100}	-	0	-	0	-.002 (.088)	2	-.015 (.050)	73	.043 (.176)	59
Adj. R^2 (N)	.388 (14591)		.431 (12476)		.324 (12528)		.344 (12528)		.281 (12528)	

Note: This table reports the coefficients on *ImportCon$_t$*Night*Load Percentile* and *ExportCon$_t$*Night*Load Percentile* from specifications of equation (28) that allowed the coefficients on *ImportCon$_t$*, *ExportCon$_t$*, *ImportCon$_t$*Night*, *ExportCon$_t$*Night* and the lagged values to vary by load percentile. For example, g_{I-25} is the coefficient on *ImportCon*Night* for periods in the 25th percentile of load levels. All specifications use the non-adjoining area as the control area. Standard errors in parentheses adjust for the presence of heteroskedasticity and serial correlation within a week. Constrained periods are identified as those in which the price difference is greater than 0.1 Nkr/MWh. Night is defined as 7 p.m. to 7 a.m. Summer is defined as weeks 18-40; winter as weeks 41-17. In Bergen, all export constrained periods in the first 25th percentile load level were during the night, so the coefficient on the interaction term is not identified.

7. OTHER EVENTS SUGGESTING MARKET POWER IN THE NORD POOL AREA

The methodology that we have used thus far to identify market power would be inappropriate if generators had incentives to exercise market power that did not vary systematically between days and nights, or, worse, that were stronger during the day. Also, if the elasticity of demand does not change between day and night or if the ability to exercise market power does not change with transmission constraints, our methodology would not identify markups. In this section, we comment on a number of incidents in the Nord Pool area that have been or could be linked to market power abuses that our methodology may have failed to identify.

7.1 October 1992 – Minimum Bid Price Commitment

In the autumn 1992, the Norwegian day-ahead price increased fivefold over the course of several weeks. The Norwegian Competition Council investigated the case but found no signs of illegal behavior. Sørgard (1997) claims that Statkraft employed market power to increase the price. He refers to a meeting that took place when spot prices were about 20 Nkr/MWh. During the period when prices were low reservoirs were filled up to 96.5 percent of capacity and any additional inflow would have to be spilled. This period also had unusually high inflows and low demand due to mild weather. At the meeting Statkraft committed not to bid a price less than 100 Nkr/MWh. Subsequently, prices did rise to above 100 Nkr/MWh. This was cited as a case where Statkraft's commitments led to the price increase.

However, it is possible that the prices would have increased irrespective of Statkraft's commitment as reservoir capacities were drawn down and generators no longer needed to spill water but could begin storing inflows. Soon after the meeting, it became colder and demand increased rapidly. Moreover fresh precipitation came as snow, and the overflow was quickly eliminated. When overflow came to an end, the marginal cost of producing hydropower reflected the discounted, expected future price of electricity (water) and spot prices increased. It is possible that what Statkraft really did was to predict a weather-change which they knew would occur in the very near future.

Wolak (1999) goes even further than Sørgard, suggesting that the high prices were not sustainable. However, it is possible that the price reductions observed in the spring of 1993 were driven by snowmelt. Without more specific information about daily fluctuations in the reservoir capacities, it is impossible to verify that the specific prices observed reflected market power abuses.

7.2 Autumn 1996 – High Prices

Very low snow volumes in the mountains throughout the winter of 1995 caused very low inflows during summer 1996. In addition, the first part of the autumn was dry and the day-ahead prices increased quite substantially, as did the futures price. During this period, a number of generators sold futures or offered long-term bilateral contracts at very high prices. The last part of the autumn was wet, consumption fell as a result of high prices and the market became less tight. Prices fell considerably at the end of 1996 and beginning of 1997, (see Figure 6, weekly spot price in section 2). The companies that bought futures and bilateral contracts when prices were extremely high faced heavy losses since few of them had backed their purchases with long term sales contracts with their end-users. As a result, more than 15 energy company directors were fired throughout 1997. Newspaper reports claimed that Enron helped a number of companies to spread their losses over a number of years [Skaslien, 1998].[25] Enron took over the futures and bilateral contracts and in exchange the companies had to take 10-year long bilateral contracts with Enron at a price slightly above the expected future prices.

It is possible that the high day-ahead prices in the early autumn of 1996 were due to market power, and that some producers stored water in order to raise prices while attention was focussed on the drought? Calculations made in September 1996 [Eika and Johnsen 1996] based on simulated demand, expected inflow and maximum import throughout the winter, predicted a very tight market balance at the end of the winter and the high day-ahead prices seem to reflect expectations of a tight market rather than market power.

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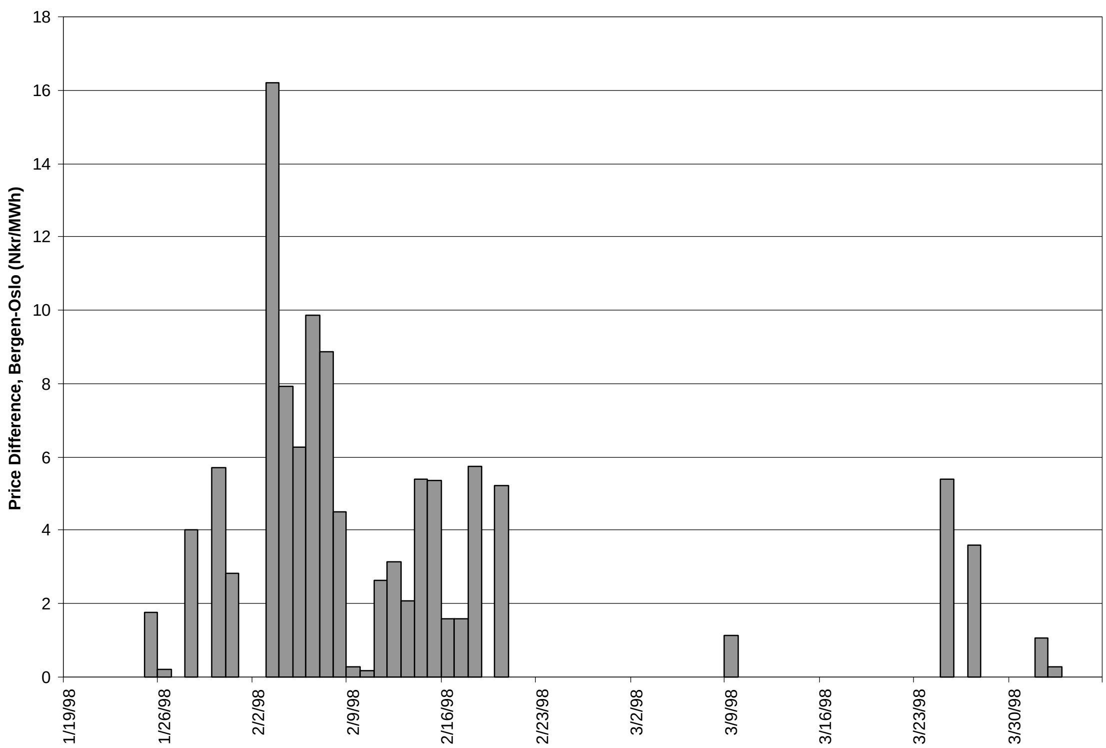
[25] Web link to newspaper at http://www.aftenposten.no/nyheter/okonomi/d37183.htm

7.3 Winter and Autumn 1998 – High Prices in Bergen

The Bergen area in the western part of Norway (see Figure 1) was import constrained for about 25 percent of the hours in 1998. Throughout the first half of 1998, there were several short periods with higher prices in Bergen than in the rest of the country, see Figure 12.[26] Similarly, in the autumn and towards the end of 1998, Bergen was import constrained for a large number of hours. The price in Bergen was higher than in Oslo by 25-40 Nkr/MWh. These repeated periods of constrained hours with high prices could indicate that there was an attempt on the part of some generators to restrict output in order to drive the price up temporarily.

Figure 11: Mean Day-Ahead Price Difference Between Bergen and Oslo, Jan 25-Apr 3, 1998



On October 27th, day-ahead prices rose by 300 percent compared to the day before. We have not found any information of plant or transmission line outages , or of unusual demand that would explain this increase, so there is reason to suspect that this was indeed an exercise of market power. If we had data on production disaggregated by

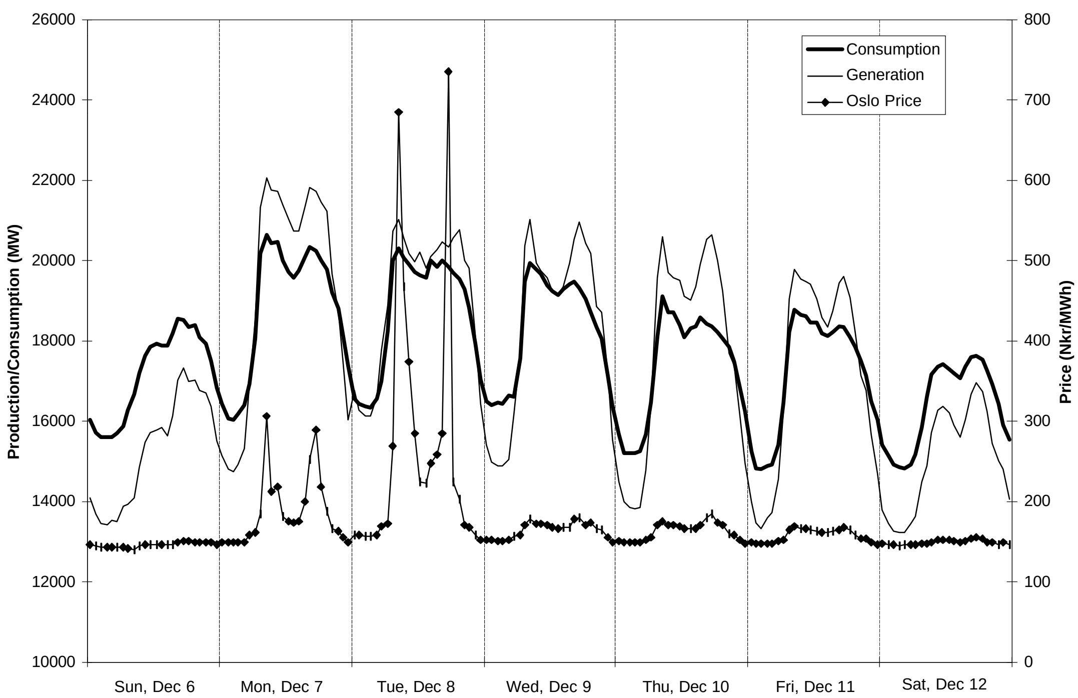
[26] There were also two shorter periods with high prices at the end of May

region it would be possible to assess whether generators were indeed restricting output during these periods.

7.4 December 1998 – High System Prices

The first week of December 1998 was an unusually cold period in Norway, resulting in high demand. As a result reserve capacity was reduced to about 150 MW on Monday, December 7. The grid operator, Statnett requested generators not to bid specific plants during the next day in order to increase the reserve capacity to about 1,000 MW. This should not have resulted in a price increase unless there was additional generation needed on the following day. However, prices increased from 150 Nkr/MWh to more than 700 Nkr/MWh (see Figure 13).

Figure 12: Prices, Generation and Consumption, Early December 1998



Individual generators may have realized that there was a high probability that certain plants would be monopolists to the residual demand during some hours. Thus, they could behave as monopolists during those hours. On December 9, prices returned back to normal, despite the fact that generation was about the same as the day before. This seems to be a clear example of restricting capacity during peak hours. A more systematic study of capacity restriction during peak hours could reveal more examples of this behavior.

8. CONCLUSIONS

The analysis in this paper focuses on identifying market power in the day-ahead market in Norway. We show theoretically that even though hydro producers dominate the market, they may have incentives to withhold capacity when transmission constraints bind because they can later use water when there are no constraints and the market is less concentrated. Because assessing the shadow value of water at a point in time is nearly impossible, we cannot directly measure whether generators are able to mark up prices above costs. We rely on a methodology that involves comparing prices across periods when demand elasticity changes and when transmission constraints change the concentration of the markets in which firms compete. While our methodology draws heavily on standard techniques from the IO literature (see Bresnahan, 1989 and the references he cites), our application is particularly clean since transmission constraints and elasticity changes are largely exogenous. Our current results rely simply on elasticity differences between days and nights. If we had data on the shape of the demand curves bid into the market, we could make more sophisticated comparisons across periods and draw firmer conclusions about the extent of market power.

We identify evidence of market power in one of the five areas we study, Kristiansand, and limited evidence in Bergen. Notably, Kristiansand is the only area in which Statkraft is not one of the four largest producers. This could suggest that Statkraft does not take advantage of transmission constraints to withhold supply and drive up local prices since they would be reducing the price of electricity in later periods in all areas and thus affecting their revenues from other areas. It is also possible that the county-owned generators have stronger incentives to take advantage of temporary transmission constraints to maximize profits in Kristiansand, for instance, because their budget constraints are more binding.

There is reason to suspect that there may be market power that we are unable to identify. Other authors have suggested that there may be more market power during periods of high demand as the fringe supply becomes capacity constrained [see, for example, Borenstein et al., 1999]. Our results by load levels in Table 10 confirm that this might be the case in Kristiansand. However, to the extent we use price changes during constrained days as controls, our methodology would specifically *not* identify price increases due to higher market power during supply constrained days. In section 7, we identify several events that have led to speculation about market power. Without more disaggregated data on generation, consumption, storage and inflows, however, it is impossible to differentiate between market power explanations and cost changes. These incidents provide some direction for further research.

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