Increased Concentration in the Norwegian Electricity Market: Is the Market Sufficiently Open, or Can a Dominant Norwegian Power Company Raise Prices?

*By Tor Arnt Johnsen **

Many restructured electricity markets have experienced market power problems. Market power has not played an important role in the Norwegian market. International comparisons show that Norway has low prices. If market power has been applied, it has not led to large price increases for long periods. However, market concentration has increased over recent years, and privatization of major electricity producers may be part of future development. In order to continue to have a well-functioning and efficient power market, it is important to maintain a concentration level that stimulates competition.

Introduction

Since 1991, when the Norwegian electricity market was liberalized, mergers and acquisitions have led to a reduction in the number of generators. Statkraft, the large state-owned generator is one of the companies that has grown through various acquisitions. In Norway, the Competition Authority has to approve mergers and acquisitions and until 2001 they allowed this structural change to continue. However, when Statkraft in 2001 bought 45.5 percent of the shares in Agder Energi, the Competition Authority did not approve the transaction. The Ministry of Labor and Government Administration has the final word in such cases. Finally, the Ministry gave Statkraft permission, with conditions, to buy the shares of Agder Energy. The conditions were that Statkraft sell its shares in E-CO (Oslo Energy) and HEAS (Hedmark Energy). In addition, Statkraft has to sell 1 TWh of capacity. However, if the transmission capacity into South-Norway is increased by 200 MW before a given time, this last condition (1 TWh sale) may be dropped. However, Statkraft continues to expand and recently acquired 100 percent of the shares in Trondheim Energiverk, another large generation firm. The Competition Authority has stopped this case as well.

These cases have triggered discussion about market power issues within the Nordic and in particular Norwegian electricity market. In this article, we describe these markets, and we discuss how a dominant hydropower generator may apply market power in the Norwegian power market.

The rest of the article is organized as follows: In the next section, we give a brief description of the physical production and transmission system in the Nordic area, and we give some background information about the liberalization that was undertaken in 1991. Next, we describe the current structure and concentration at the supply side of the Norwegian market. Thereafter, we discuss market power in a Norwegian context. We focus on a hydropower production system with transmission connections to neighboring countries with thermal power production systems. In particular, we focus on the potential for using market power within seasonal and daily time horizons. Finally, we draw some conclusions.

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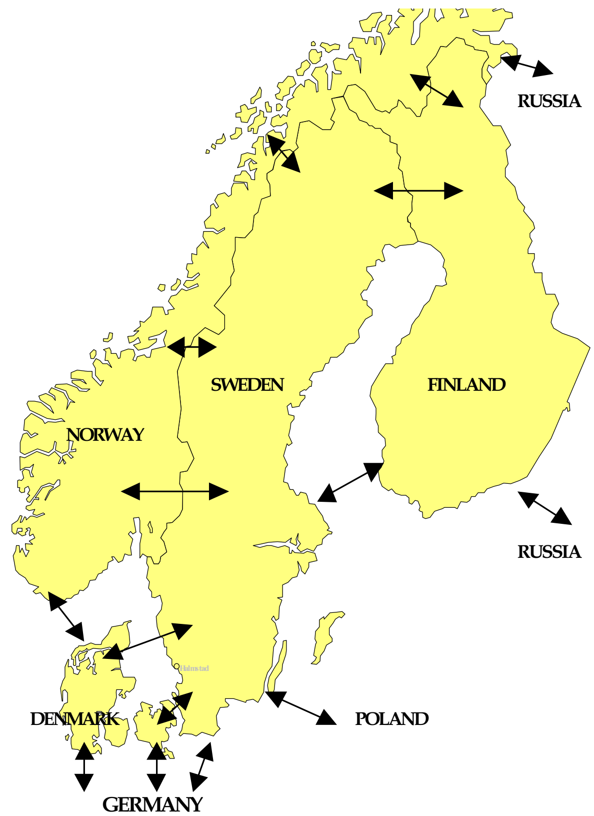
Background

The Nordic Power System

Annual power consumption in Norway is 125 TWh, while total Nordic consumption is about 380 TWh. Thus, we are talking about a market of the same magnitude as the British or German power markets. Figure 1 shows the geographical area and transmission connections between the Nordic countries and between the Nordic area and other European countries.

Figure 1
The Nordic Electricity System



There are a large number of transmission lines and sea cables between Nordic countries and between Nordic countries and non-Nordic countries, see Table 1.

Table 1
Transmission Capacities, MW

From: To:	Norway	Sweden	Denmark	Finland	Non-Nordic Countries
Norway		3170	1040	70	50[a]
Sweden	2990		1840	1700	1200[b]
Denmark	1040	1840			1400[c]
Finland	100				0
Non-Nordic Countries	50	1200	1800	1500[d]	

[a] To Russia, [b] To Germany and Poland, [c] To Germany, [d] From Russia
Source: Haug and Johnsen (2002).

Transmission capacities depend on the actual network configuration, and capacities are not always the same in both directions. Table 1 gives upper estimates of available capacities.

There are large differences with respect to generation technologies across the Nordic countries, see Table 2.

Table 2

National Power Generation in 2001. TWh

	Hydro	Nuclear	Other Thermal[a]	Wind
Norway	121		1	
Sweden	78	69	10	
Denmark			32	4
Finland	13	22	36	

[a] Condensing, district heating and industrial back-pressure stations fueled by coal, gas, oil and biomass.

Source: Nordel (2002)

More than 99 percent of Norwegian generation is hydropower. In Sweden, almost 50 percent of generation came from hydro in 2001, while nuclear power accounted for about 40 percent and the rest was conventional thermal. Swedish hydropower has a larger fraction of run of river generation and relatively less reservoir capacity than in Norway. Coal based thermal power dominates in Denmark. Heavy subsidies to wind power projects in Denmark have led to an increasing share of wind power. In 2001, wind covered more than 10 percent of generation. Finland has hydro, nuclear and conventional thermal power. In Finland hydro accounts for only 20 percent of generation, 30 percent is nuclear, while the rest is conventional thermal power.

Restructuring Status

The Norwegian power market was restructured in 1991. Unbundling of generation and network services and mandatory separation of the accounts for generation, transmission, distribution and sales activities were introduced. Generation and sales are competitive, while transmission and distribution are regulated natural monopolies. Transmission and distribution are from 1997 due to income regulation with the income revised every fifth year. The regulatory authority is the Norwegian Water Resources and Energy Directorate (NVE).

Power is traded in voluntary day-ahead, futures and forward markets. Based on predicted generation, consumption and network availability, the system operator, Statnett SF, defines the geographical zones into which the day-ahead market is divided. Normally, two or three Norwegian zones are declared ahead of each season. Bilateral trade between parties located in different zones has to be bid as sale in the generating zone and purchase in the consumption zone. Zones expected to last for less than three days are normally not defined. Short term transmission congestion and short run discrepancies between demand and supply are treated in a real-time market operated by the system operator.

Finland (1995), Sweden (1996) and Denmark (1999/2000) have followed in Norway's footsteps and liberalized their national electricity markets. Sweden and Finland do not apply price-zones when there are bottlenecks within the national grids. These two national markets are separate zones at Nord Pool, and the national system operators relieve intra-zonal congestion by sales and purchases in the real-time (balancing) market. The word "counter-trade" is used when the system operator buys and sells in order to eliminate national bottlenecks. Denmark consists of two parts, East- and West-Denmark, that are not electrically connected. Thus, there are two Danish price-zones. The two Danish system operators apply counter-trade if there is transmission congestion within any of these two zones.

The Nordic power exchange, Nord Pool, is the most important marketplace. Nord Pool's day-ahead market consists of 24 hourly markets. Market participants prepare and submit bids for the coming day before noon the day before, or 12 to 36 hours prior to the actual hour. Available information is the number and configuration of price areas and the transmission capacities between the price areas determined by the Nordic transmission system operators.

Structure at the Supply Side

Table 3 shows the largest Norwegian hydropower producers and their market shares based on expected generation in a year with normal hydrological conditions.

Table 3

Market Shares in Norway and the Two Most Common Norwegian Price-zones.

Percent Calculated From Generation (TWh) in a Year With Normal Precitipation

	Norway	South-Norway	Mid- and North-Norway
Statkraft and partners[a]	41	38	50
E-CO[b]	8	10	
Norsk Hydro	7	10	
Agder Energi	6	9	
Lyse	5	7	
Trondheim Energiverk	3		11
Nord-Trøndelag	2		9
Trønder Energi	1		5
Salten	1		4
Other	24	26	21
Herfindahl-Hirchman Index	0.19	0.18	0.28

[a] Partners are companies where Statkraft owns more than 49 percent or more of the shares. BKK (49.9 percent), HEAS (49) and Skagerak (66.6) are included.

[b] Statkraft owns 20 percent of the shares in E-CO

Note: Statkraft owns 35 percent of the shares in the Swedish company Sydkraft, which owns 26.5 percent of the shares in Hafslund. E-CO owns 30 percent of the shares in Buskerud.

Source: Norwegian Competition Authority (2002).

Statkraft is a large state-owned producer with power plants in many different parts of the country. At the national level, Statkraft, including companies where Statkraft owns 49 percent of the shares or more, have a market share of 41 percent. In addition, Statkraft owns, directly or indirectly through a third company, smaller parts of seven other Norwegian producers. Most frequently, Norway has two price-zones, South-Norway and Mid- and North-Norway. Statkraft and partners have a market share of 38 percent in South-Norway, while Statkraft's market share in Mid- and North-Norway is 50 percent. The Herfindahl-Hirchman Index (HHI) is 0.19 at the national level, 0.18 in South-Norway and 0.28 in Mid- and North-Norway.

If we add Agder Energi and Trondheim Energiverk to Statkraft and partners, Statkraft's shares of the market become 50, 47 and 61 percent in Norway, South- Norway and Mid- and North-Norway, respectively. The accompanying HHI will change to 0.27 at the national level and to 0.25 and 0.39 for the two regions. Consequently, the two acquisitions, if they are completed, will increase market concentration substantially.

In a Nordic context, Statkraft and partners have a market share of 12 percent. It increases to 15 percent if we add Agder Energi and Trondheim Energiverk. Vattenfall, the large Swedish producer, and the Finnish company, Fortum, are the largest Nordic producers with market shares of 21 and 15 percent.

Market Power Within a Hydropower System

Norwegian power generation is purely hydroelectric. Normally a power plant consists of a water reservoir, the power station with one or more turbines and one or more pipelines that connect the reservoir and the power station. Water is collected from snow melting mainly in June, July and August and from rainfalls throughout the year, most intensive in September and October. The load is highest in the winter, November to April. The national reservoir capacity is 81 TWh or about 75 percent of annual consumption. Consequently, storage of water and the disposal of the water resources over time become seriously important decision variables for power producers.

If producers know that by acting strategically they are able to affect the market price in a profitable way, they will try to increase the price level. Traditionally, it is normally assumed that the strategic behavior is to withhold output in order to reduce supply and increase the price. However, if a hydro producer withholds generation, he will end up with more water in the reservoir. Over time this may lead to spill and lost production possibilities. In addition, overflow and spill of water may be observed, and producers that spill water run the risk of being detected by the authorities. For a thermal power generator, the difference between the market price and marginal cost for the last produced units may be zero or very low. Therefore, the loss from withholding production may be very low for a thermal producer. For a hydropower producer spill implies lost production and since spilled water has no opportunity value the loss per unit may be large.

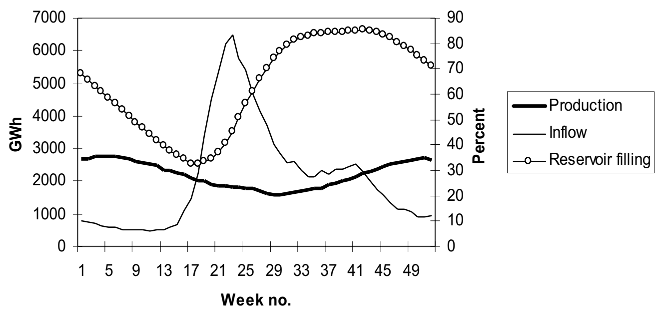
While the withholding of hydropower generation and spill of water definitely are profitable for producers that are large enough, we do not consider such strategies in this article. A large number of academic articles and papers discuss withholding strategies at length, and the outcomes of such strategies are well known. Therefore, we focus on applications of market power in hydro systems under an assumption of no spill of water.

Seasonal Aspects

Figure 2 shows the typical seasonal pattern of power production and water inflow in Norway over the course of a year. During the winter, production is larger than inflow and water is withdrawn from reservoirs. Normally, the amount of water in the reservoirs decreases until week 18. At this time snow melting accelerates and reaches a maximum around week 24. Inflow stays higher than production until week 42, when there are lower temperatures in the mountains and the precipitation turns out to be mostly snow. Between week 42 and week 18 the next year, production mainly relies on the water stored throughout the summer.

There are large variations in inflow in the short-run, and from year to year. The annual production potential may vary at least +/- 25 percent compared to the production in a year with normal precipitation. The hydrological situation – water storage and snow volumes – are very important for the price formation, see Johnsen (1998). The most important cost component related to hydropower generation is the opportunity value of water, or the discounted expected market price in the future. Future market prices will depend on the expected inflow and the water available in the reservoirs. The decision on how much to produce today and how much to store, is made under uncertainty.

Figure 2
Production and Inflow (left axis) and Reservoir Filling (right axis) for the Norwegian Hydropower System.
Weekly Averages Based on the Period 1991-2000



Source: Nord Pool ASA and Statistics Norway.

During summer, producers will compare the market prices with expected prices for the coming winter and be more willing to store water if the actual prices are lower than discounted expected prices for the winter. However, since reservoirs have a maximum capacity there is a probability of overflow by the end of the summer. As this probability increases, the profitability of storage is reduced, and the link between summer and winter prices becomes weaker.

In the winter season, we expect producers to compare the current price and the discounted expected future prices. If the probability of empty reservoirs and high prices by the end of the winter increases, producers reduce their use of water and store more for the future. Consequently, current prices rise.

A dominant producer may find it profitable to deviate from the competitive behavior sketched above. By producing more at the beginning of the summer and winter seasons he will reduce the probability of overflow in the autumn and increase the probability of low reservoir filling by the end of the winter. Whether such a strategy is profitable or not depends on a large number of assumptions. The dominant producer's market share, price elasticities and other producers' response are important variables.

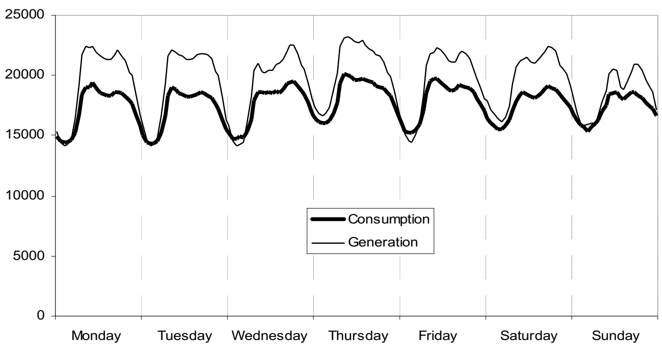
However, the uncertainty about future conditions is large and hydrological conditions change continuously. Ex post, producer strategies may look inoptimal, while they actually were optimal ex ante. Because of the large uncertainty, it is also hard to distinguish between strategic behavior due to imperfect competition and rational price-taking behavior.

Hourly Considerations

While strategic movement of water and production within seasons has to take into account the inflow uncertainty, short-term production decisions within the day can be made without considering hydrological uncertainty. However, market conditions change drastically over the course of a day.

Figure 3 shows consumption and generation in Norway hour by hour throughout week 51 – 2001. Generation rises more than 50 percent from night to day and varies more than consumption does. During this particular week, there were only a small number of hours with import. Night generation was close to the actual consumption, while there was heavy export during daytime.

Figure 3
Norwegian Electricity Consumption and Generation
Week 51 – 2001. MWh/h

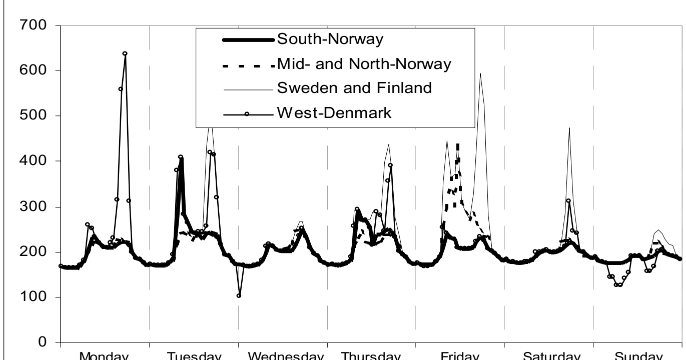


Source: Nord Pool ASA

Norway's neighboring countries have electricity systems dominated by thermal power, see Table 2. Thermal power is less flexible than hydropower, and it is costly to regulate output up and down in the short-term. Consequently, thermal power producers prefer stable output, and they are often willing to continue to produce during night in order to avoid stopping. Similarly, they need high prices during the day to make it profitable to start up new units for production during daytime only.

The large variation in consumption over the day and the thermal power cost structure result in larger price volatility in thermal systems than in hydropower systems. Day-ahead prices for week 51 – 2001 are illustrated in Figure 4.

Figure 4
Nord Pool's Day-ahead Prices
Week 51- 2001. NOK/MWh*

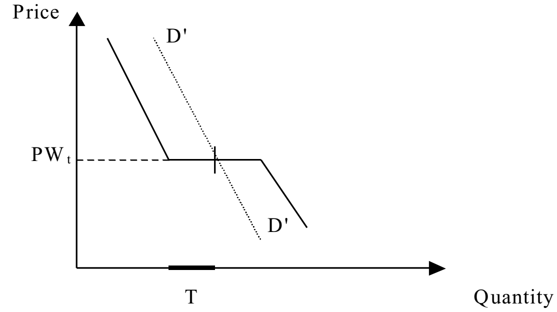


* 1 US$ is approximately 8 NOK
Source: Nord Pool ASA

As expected, prices in Norway are more stable than prices in neighboring countries. Every day there are peak periods with lower prices in Norway than in the other countries. Price differences mean that the available transmission capacity is fully utilized. In periods with lower prices in Norway than in other areas, there is export at full capacity, and Norway is a separate market. In periods without price differences, the transmission capacity is not used and there is an integrated Nordic market. As indicated above, Norwegian prices are lower than foreign prices only in hours where the Norwegian prices, consumption and generation are at their highest levels.

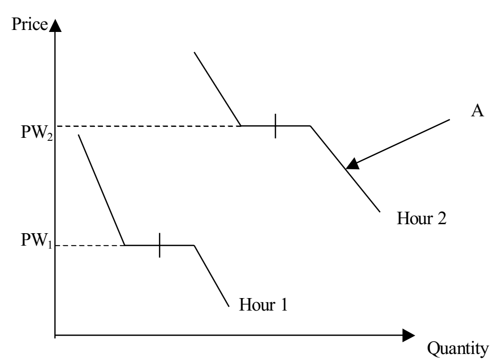
We can illustrate the market situation given by Figures 3 and 4 within a simple graphical example. For a moment, we assume prices in neighboring areas to be fixed. This assumption allows us to draw the demand curve directed against Norway's incumbent generators as in Figure 5.

Figure 5
The Demand for Electricity in Norway in a Particular Hour



Norwegian electricity demand is given by the dotted curve D'-D'. At prices above the foreign price (export/ import price, PW_t), demand directed towards Norwegian producers is shifted leftwards by a quantity equal to the import capacity (T). If price is lower than the foreign price (PW_t) demand is shifted rightwards with the export capacity (T). Each of the 24 hours throughout a day may be described with a figure similar to Figure 5. The only difference is the level of PW_t and the level of Norwegian demand. A typical pattern for two different hours may be as indicated in Figure 6.

Figure 6
Demand in Two Hours



Hour 1 is a night hour with low international prices and low demand in Norway. Hour 2 is an hour with high demand and high international prices.

The power supply from Norwegian generators determines the local price levels and power exchange with neighboring regions. We do not know the level or curvature of the marginal cost curve. However, even without knowledge about marginal costs it is easy to see that power producers have a common interest in not being export-constrained in hours with high demand and high prices in neighboring areas. Increased generation when export capacity is filled up, has, when the price elasticity is small, dramatic consequences for the price.

If, for instance, the perfectly competitive solution is market clearing in the point A in Figure 6, producers have a strong incentive to reduce generation in hour 2. Reduced generation in hour 2 will increase price for a large generation volume. The quantity of water that is saved can be produced in another hour in which there is no transmission congestion. Without transmission congestion, the increased production is absorbed in a complete Nordic (or even European) market, and the price decrease will be modest.

A Numerical Example

In order to discuss strategic behavior within this hourly model, we will apply a simple numerical example. We consider strategic movement of water between two hours of the same day. We compare a competitive benchmark with a situation where a large generator (leader) with a market share of 50 percent, moves output from the hour with high demand, high price and export constraint (hour 1) to an hour with low demand, low price and an integrated Nordic market (hour 2). A competitive fringe consisting of a large number of smaller producers constitutes the rest of the market. The total generation capacity is 23000 MW, and the leader and fringe have a capacity of 11500 MW each.

With a competitive solution, Norwegian demand is 18000 MW in hour 1 and the competitive price is 200 NOK/MWh. There is export at full capacity (3600 MW) and Norwegian generation is 21600 MW. The leader and fringe produce 10800 MW each. The Swedish price in hour 1 is 300 NOK/MWh. In hour 2, the Norwegian and Swedish prices are equal – 150 NOK/MWh. Generation equals consumption and is 14000 MW and there is no foreign trade. The leader and fringe produce 7000 MW each. The competitive solution and resulting producer incomes are indicated in the left panel of Table 4.

The right panel of Table 4 gives the market outcome when we allow the leader to act strategically. He finds it profitable to reduce generation in hour 1, and he reduces output until the bottleneck between Norway and Sweden disappears. We assume the price elasticity within Norway to be constant and equal to –0.05. With this elasticity, Norwegian consumption falls with 361 MW as the price in hour 1 increases from 200 to 300 NOK/MWh. However, the leader needs to reduce his output by a larger quantity in hour 1, because the strong price increase motivates the fringe to generate as much as possible. Thus, the fringe increases output from 10800 MW to maximum output, which is 11500. Therefore, the leader has to reduce output by 1061 MW in hour 1. Both the leader and fringe benefit heavily form this behavior. Compared with the competitive solution, their incomes in hour 1 rise by 760.000 and 1.290.000 NOK, respectively.

Since the leader reduces output in hour 1, he has to increase output in hour 2, and the price in hour 2 decreases. The price reduction and the increase in the fringe's generation in hour 2 lead to lower output from the fringe in hour 2. The net increase in generation in hour 2 equals the consumption reduction in hour 1, which was 361 MW. Since there are no transmission constraints in hour 2, this quantity is absorbed in the complete Nordic market. We assume the price elasticity to be the same as in hour 1, -0.05. Given an initial Nordic consumption in hour 2 of 35000 MW, the price in hour 2 falls from 150 to 122 NOK/MWh. Compared to the competitive solution, both the leader and fringe receive lower incomes in hour 2, -65.000 and –280.000 NOK. However, the net change in income from hour 1 and 2 is 700.000 NOK (+23 percent) for the leader and 1.000.000 NOK (+30 percent) for the fringe. The detailed figures for the competitive and leader/fringe market solutions are shown in Table 4.

It is worth noting that some of the increased generation in hour 2 is exported. In aggregate, the quantity supplied in the Norwegian market is reduced. This behavior is, therefore, comparable with "dumping".

The calculations in Table 4 may be done for other values of critical parameters. Price elasticity, price level in Sweden, Norwegian demand level and the market share of the dominating firm are important variables. With respect to price elasticity it has two opposite impacts. First, larger price elasticity will increase the consumption reduction in hour 1,

Table 4
Impacts on Market Prices and Producer Income

Variable	Unit	Competitive Solution: Norway	Competitive Solution: Large	Competitive Solution: Fringe Producer	Large Producer Withholds: Norway	Large Producer Withholds: Large	Large Producer Withholds: Fringe Producer
Generation capacity	MW	23000	11500	11500	23000	11500	11500
Hour 1: An hour with export at full capacity and higher price in Sweden than in Norway							
Generation	MW	21600	10800	10800	21239	9739	11500
Consumption	MW	18000			17639		
Price in Norway	NOK/MWh	200	200	200	300	300	300
Price in Sweden	NOK/MWh	300	300	300	300	300	300
Sales income	NOK		2,160,000	2,160,000		2,921.627	3,450,000
Change in sales income	NOK					761,627	1,290,000
Hour 2 : An hour without transmission congestion and equal prices in the Nordic area							
Generation	MW	14000	7000	7000	14361	8061	6300
Consumption	MW	14000			14144		
Price in Norway	NOK/MWh	150	150	150	122	122	122
Price in Sweden	NOK/MWh	150	150	150	122	122	122
Sales income	NOK		1,050,000	1,050,000		984,699	769,559
Change in sales income	NOK					-65,301	-280,441
Aggregate change in incomes:							
Sales income hour 1+2	NOK		3,210,000	3,210,000		3,906,326	4,219,559
Net income change	NOK					696,326	1,009,559

and the leader has to reduce output more in order to receive the Swedish price. Second, increased generation in hour 2 will lead to a smaller price reduction if the price elasticity is large. This will reduce the losses in hour 2.

With respect to other values for the differences between the Norwegian and Swedish price in hour 1, Norwegian demand and the market share, there will be combinations that make it unprofitable to act as a leader. Other combinations make it profitable to apply the leader strategy. Throughout the 8760 hourly markets of a year there will clearly be many opportunities for a dominant producer to increase price and income through a strategic behavior as sketched here.

We have not focused on the welfare implications in our example. Traditional deadweight losses will be relatively small since price elasticity is low. Since the overall price level is affected, long-term decisions are affected as well. In addition, many authors question the deadweight loss as a good indicator of the welfare impacts of market power abuse. Unproductive profit seeking and X-inefficiency are keywords in that debate, see Posner (1975).

Concluding Remarks

While there are no clear signs of market power in the Norwegian market today, increased concentration may lead to higher prices in the future. Dominant generators may apply market power in various ways. In this article, we have discussed redistribution of output over the day or season. Limited transmission capacity and differences in the generation technology mix across the Nordic countries, make it possible for a dominant Norwegian hydropower producer to affect Norwegian power prices in a profitable way. Market power reduces efficiency, and market participants do not trust in the market any longer. Therefore, it is important to limit the number of new mergers and acquisitions in this market and thereby avoid increased concentration.

References

Contact the author for references.

2004 IAEE International Conference Planning Meeting, 8 December 2002, Tehran, Iran, Hosted by the Iranian Association for Energy Economics (IRAEE)

Pictured from left to right: Jan Myslivec, Czech IAEE Affiliate, David Williams, IAEE, Majid Abbaspor, IRAEE President, Tony Owen, Australia Affiliate & 2004 IAEE President-Elect, Arild Nystad, IAEE VP for Conferences & IAEE Past President, Reza Farmand, IRAEE Board Member, Mohammad Mazraati, IRAEE/IAEE Member, Seyed Alavi, IRAEE Board Member and 04 IAEE General Conference Chair, Mohammad Reza Omidkhah, IRAEE Board Member and Gholam Hosein Hassantash, IRAEE Vice President

IAEE leaders were present at the 7th IIES International conference in Tehran December 8-10, 2002. The conference is also hosted by the Iranian Association for Energy Economics (IRAEE) and proved to be a most opportune time to meet with Affiliate leaders to discuss progress in planning of the 2004 IAEE International Conference to be held in Tehran, Iran – **April 30 – May 3, 2004.**

The IIES Conference entitled “The Impact of Globalization on Middle East Oil and Gas Industry” highlighted current research and developments affecting the Middle East as it supplies petroleum/gas worldwide. The conference was chaired by IAEE member Dr. Seyed Alavi and convened with noteworthy speakers including:

Dr. Fereidun Fesharaki, President, FACTS, USA
Mr. David Fitzsimmons, Group Vice President, BP, UK
Mr. Olav Fjell, President & CEO, Statoil, Norway
Mr. Masahisa Naitoh, Vice Chairman, Itochu, Japan
HE Bijan Zanganeh, Minister of Petroleum, I.R. Iran

IAEE representatives attending this meeting and discussing the developments of the 2004 IAEE International conference consisted of Dr. Arild Nystad-Norway (IAEE Past President & Vice President for Conferences), Dr. Anthony “Tony” Owen-Australia (IAEE 2004 President-Elect & Past Conference Chairman), Mr. Jan Myslivec- Czech Republic (2003 IAEE General Conference Chairman & Council Member), and David Williams-USA (Executive Director, IAEE).

IAEE saw first hand how active and devoted the Iranian Association for Energy Economics is to planning a most successful International conference on behalf of the association in 2004. Seen above is a picture of those in attendance at the Affiliate/IAEE planning meeting for the conference. Topics discussed included conference content, (e.g., representation of a well balanced program), special technical and social tours, conference venue and attracting an international IAEE audience to Tehran.

IAEE witnessed the ease of travel to/from Iran as well as how welcome the Iranians make everyone feel. The IRAEE is pledged to provide a superior conference and we encourage all IAEE members to mark their calendar for this meeting. IRAEE members will attend the Prague conference to promote the meeting and solicit for program support. If you are interested in participating in the program committee please send an email to David Williams at iaee@iaee.org indicating your energy expertise and intended contribution to the 2004 program committee for consideration.

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