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A Model of Imperfect Dynamic Competition in the Nordic Power Market

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Abstract

This dissertation presents a framework for testing for market power in storable-good markets. The framework is applied to the Nordic wholesale electricity market, in which the storable commodity is hydroelectricity. The marginal cost of a unit of hydro output arises from the opportunity cost of not being able to sell the unit in the future. Thus, to measure price-cost margins, the economist must evaluate the value of the water at the state of the market where the production decision is made. This value depends on the hydro producers' expectations about the future market conditions. The Nordic power market presents a unique opportunity for testing the nature and degree of market power in storage behavior, because of the availability of precise data on market fundamentals, which determine the expectations about the future value of water.

The thesis first develops a model of socially optimal hydro allocation. This competitive benchmark is modeled as an aggregative single agent stochastic dynamic programming problem, and is solved numerically on the computer. The key inputs of the model are estimated from actual market data. The model can be used to construct distributions of the expected values of the key market outcomes, such as storage levels, prices and outputs. The expected price of electricity is shown to exhibit features that are typical for both exhaustible resources and for storable goods. The results from the benchmark model also suggest that the observed market behavior in 2000-05 was markedly different from the social optimum. This inefficient allocation of the hydro resource is estimated to have lead to a welfare loss of 621 million euros.

To study whether the welfare loss can be attributed to market power, the thesis next develops an explicit model of dynamic imperfect competition. The model maps the primitive distributions to market outcomes as a function of the market structure. Empirical models of dynamic imperfect competition where the product market equilibrium is connected to the dynamics of the state of the market are very scarce in the literature. The model presented here is built upon a dominant firm approach, which greatly facilitates the computation of the model. Apart from the change in the market structure, the model is unchanged from the model of competitive behavior. The computational tractability enables the estimation of the market structure that best explains the observed market behavior.

It is shown that a model, where 30 per cent of total hydro resources is controlled by a single firm, and the rest by competitive producers, provides the best fit with the historical market outcomes. Market power is shown to lead to higher expected storage levels, prices and price risk. However, the expected welfare loss from the estimated level of market power is very small. The estimated, relatively large welfare loss in 2000-05 is shown to have arised from an exceptional inflow shortage in 2002, which enabled the strategic hydro firms to reduce output profitably. Finally, the thesis studies the possibility that the pattern attributed to market power could also be explained by some mismeasured or unobserved factors. However, the main results are shown to be robust to several reparameterizations of the model of competitive hydro allocation.

Keywords: *storage, hydroelectricity, resources, market power, Nordic power market*

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Acknowledgements

During my graduate studies, I was fortunate to make many friends, and to share several entertaining evenings with them. On one such occasion, overcome with positive feelings towards my colleagues, I apparently promised to dedicate at least a page to each of my friends and supporters in the acknowledgements of my dissertation. Now, with the task at hand at last, I realize that such a eulogy, well-earned as it would be, might overshadow in length the actual thesis. Thus, with due apologies, I have chosen to shorten these words of thanks a little bit, wishing that the reader will sense the depth of emotion condensed in the following lines.

I would not be in my current predicament unless for a phone call I made at the end of my Master's studies. I had been looking for a suitable topic for my thesis, and heard that a Dr. Matti Liski was searching for a student to work on a project on emissions trading. I remember being quite hesitant about calling; I was new to the topic, and pictured Dr. Liski as a rather stressed out individual, with very low tolerance for the trivial inquiries of unknown students (I am not sure why I had such low expectations about economists). To my surprise, Matti was not interested in rubbing my face in my own ignorance. Instead, he gave me the most thorough description of the project, making sure that I followed, and letting me ask any questions that helped me to understand. I found myself with a strange urge to know more about emissions trading.

To cut a long story short, I wrote the thesis and then became Matti's doctoral student. As an advisor, he has shown the same invaluable patience and unreservedness as during that phone call. This research was a risky undertaking, which required a certain amount of persistence to reach its fruition. It has benefited vastly from Matti's determination, enthusiasm and, most importantly, confidence in me. The fact that we got along so well on a personal level only increased my respect for him. I could not have hoped for a better mentor.

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Even the fascinating work of the graduate student is sometimes beset by monotony. I found that the best way to break it was to pay frequent visits to the delightful Satu Roponen, who never failed to cheer my spirits. Alternatively, I might seek the counsel of the sage and empathetic Hanna Virtanen, or engage in an endless debate with the ever-intriguing Torsten Santavirta. I also wish to thank Katja Ahoniemi, Anni Heikkilä and Heli Virta, as well as the whole younger generation of graduate students for making the department such a fun place to work in.

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Chapter 1

Introduction

The Nordic power market covers the four continental Nordic countries: Finland, Denmark, Norway and Sweden. Through their national transmission system operators, the countries own and run a common power exchange, the Nord Pool, where private parties can procure and sell electricity. As the first international power market, and as one of the very first deregulated electricity markets in general, the Nordic market is among the best-known examples of electricity restructuring.

On average, one half of the annual Nordic consumption is met by hydroelectricity. Owing to this plentiful resource, the Nordic countries have enjoyed relatively low and stable electricity prices despite their high demand for power. Yet, it is necessary to ask whether competition ensures that these resources are utilized as efficiently as they could be? Experiences with deregulated markets around the world have highlighted their proneness to market power. A generating firm with market power is able to influence the market price of electricity on its own, and to profit from such price manipulation. Economists have provided overwhelming evidence that electricity producers do exercise their opportunities to influence the market price. Thus far, the Nordic market has not been the subject of such a detailed empirical analysis. This lack of research is due to the dynamic nature of hydro power allocation, which significantly complicates testing for market power. To develop such a test is the challenge undertaken in this thesis. We present a method that can be used to test for market power in a hydro-based market, and in storage markets more generally, and apply it to the Nordic wholesale electricity market. We begin by reviewing the characteristics that distinguish hydro power from other main sources of electricity and discussing hydroelectricity's role in deregulated power markets.

1.1 Hydro power in a deregulated market

In 2006, roughly a sixth of the total electricity production in the world was generated by hydro power, making it by far the most significant renewable resource in current use.[1] While there are several types of hydro plants, a typical facility consists of a dammed body of water, or a reservoir, from which water is lead through a penstock into a turbine. The turbine transforms the kinetic energy of the falling water into mechanical energy, which is then converted into electrical energy by a generator. The maximum amount of power a turbine can generate is determined by the head, or the difference in the elevation of the forebay and the afterbay of the dam, and the flow of water, measured for example in cubic feet per second. The total energy producible by the facility depends naturally also on the availability of water in the reservoir.

[1]International Energy Agency, www.iea.org.

The availability of water is subject to the hydrological cycle, and depends ultimately on the amount of precipitation. The water that enters the reservoir is called inflow, and may take several forms, such as direct stream flow, surface runoff or groundwater flow. There is considerable uncertainty about inflow, which has important economic implications: in a given year, the water availability in the Nordic market can deviate from a median year by an amount that translates into approximately 1.3 bn € using average historical (2000-05) prices.

The operating costs of a hydro plant are very low as no fuel is needed to spin the turbines. The few costs related to the operation of a hydro facility are not truly functions of the production level. In addition, hydro plants are able to change their production level instantaneously and have virtually no start-up or ramping-up costs. This is strongly in contrast with other large generating units, which may incur significant fuel, labor and maintenance costs related to adjustment of output.

The storability of water, the flexibility of output and the low variable cost are the defining characteristics of the problem of the hydro firm. Because of the scarcity of water, a profit-maximizing hydro firm will want to allocate its output to the hours in which it receives the highest price for it. The future price of electricity is subject to multiple uncertainties, including the availability of water, the temperature-driven demand for power and the fuel prices of alternative production sources. In short, the basic problem faced by the hydro plant manager is whether to sell a unit of hydro power today, or to save it for tomorrow in the expectation of receiving a higher price.

The physical properties of hydro power entail that hydro stations can considerably mitigate the volatility of the price of electricity. Electricity markets are especially susceptible to price variation because of certain basic characteristics of the commodity. First, because electricity is non-storable, supply has to equal demand at every moment. Demand varies markedly both within the day and across the seasons. To meet peak demand requires the installation of capacity that will be idle during the off-peak hours. In many electricity markets, these peak-load plants are natural gas and oil-fired plants, which have low capital costs but relatively high variable costs. When demand is low, it may be fully satisfied by the hugely capital-intensive but low variable cost base-load plants, such as nuclear and large coal-fired plants. The difference in the marginal costs of base and peak-load plants can lead to great differences in peak and off-peak prices.

Another factor contributing to the volatility of prices is the inelasticity of the demand for electricity. Most customers are on long-term fixed price contracts, which weakens the end-user market's response to the spot price in the wholesale market. Also, in the short-run, the customers' ability to reduce their consumption during peak hours is limited, as the most power-consuming machinery and appliances cannot be replaced within a short period of time. The inelasticity of demand increases the volatility of prices by magnifying the effect of supply-side shocks. The fact that hydro resources can be allocated to the peak demand hours reduces the need for investment in high variable cost peaking plants and decreases the volatility of prices. In a competitive deregulated power market, this desirable result is attained through individual hydro firms arbitraging between the price levels. Under ideal conditions, efficient storage should equalize the expected price over time. Even if there are not enough hydro resources to completely smooth expected prices, competitive storage will lead to peak-shaving, the elimination of price spikes in expectations.

A prerequisite for the competitive outcome is that each hydro producer is small enough not to consider its own effect on the price level. This thesis focuses on the question of what happens when the ownership of hydro resources is concentrated to the degree that the condition no longer holds. Under imperfect competition, firms with market power strive to equalize their marginal revenue over time. The profit-maximizing allocation strategy is constrained by another exceptional feature of hydro power; the fact that hydro plants must eventually use all of their inflow, because systematic spilling of water is observable by the regulatory authorities. In theory, firms will try to exploit variation in the elasticity of their residual demand by withdrawing output during times when such a reduction in supply will cause the largest increase in price. Cutting back production during some hour will inevitably mean an increase in output in some future periods. The strategic hydro firm will reallocate water into the hours with the highest price elasticity, thereby depressing the price it receives for its output during that hour as little as possible.

The exercise of market power in the described manner can break the result on price smoothing. In a mixed hydro-thermal system like the Nordic market, the strategic reallocation of water will lead to inefficient dispatching of the thermal plants, thus raising the total cost of generation. In this way, ownership concentration in the hydro sector may erode the benefits from the flexibility of hydro production. Yet, the same characteristics that render hydro its price smoothing capabilities can also serve to alleviate problems arising from market power. As long as a sufficient fraction of the total reservoir capacity is controlled by competitive firms, price arbitrage will also partly counteract the strategic behavior of the dominating firms. In the Nordic market, the ownership of the hydro capacity is quite dispersed apart from the facilities controlled by the very largest producers. In our analysis below, we will be very explicit about the importance of the competitive sector in curbing the exercise of market power.

It is important to note that in real markets, prices may vary and out-right price spikes can occur even under perfect competition. To judge whether a certain price pattern should be attributed to normal competitive pricing, or to the exercise of market power by large hydro firms is a challenging task. A case in point is the sustained period of high prices in the winter of 2002-03, when very low reservoir levels coincided with record-high price levels. That the shortage of water was mainly due to low precipitation in the latter half of 2002 is undisputable, but many market observers, and the press in particular, put forward the view that the price crisis was catalyzed by excessive hydro output during the summer and fall of 2002. To rephrase this, it was suggested that the hydro producers should have saved more water during the fall to prevent the escalation of prices. At the same time, others (see e.g. von der Fehr et al. 2005) have propounded that the market functioned quite the way it was supposed to do, overcoming the hydrological shock without need for regulatory intervention.

The discussion about the events of 2002-03 is at the heart of the current research. Our focus is specifically on long-run storage decisions. In the Nordic market, the hydro stocks are the main market fundamental determining the division of labor between capacity types within and between the years. The stocks create a link between the current spot prices and the expected future prices, thereby stipulating an efficiency analysis of the long-run price levels. This focus on long-run hydro allocation distinguishes us from the existing literature on imperfect competition in electricity, which mainly deals with short-run market power exercised by producers of thermal electricity. Such markets have provided an interesting case study because of the availability of precise engineering data on marginal costs, which has allowed a direct evaluation of price-cost margins from price-quantity data.

1.2 Testing for market power

Market power in storable-good markets has been notoriously difficult to detect because price-cost margins depend on expected future market conditions that cannot be observed ex post. For example, because of the limited supply of water and the extremely low variable costs, the marginal cost of hydro power arises purely from the opportunity cost of not being able to sell the same unit in the future. To measure the price-cost margins, one needs to evaluate the expected future values at the state of the market where the output decision is made. Due to this difficulty, there is little research on market structure and storage and, in particular, empirical applications are practically nonexistent. For these reasons, a hydro-dominated market requires a novel methodological approach, and one that is quite different from that used in the previous work on electricity markets.

Solving for the equilibrium valuation of storage requires precise data on the market fundamentals that shape the market sentiment about the future conditions. We find that the Nordic market is unique in this sense. As an electricity market, it is subject to regulatory oversight, providing a wealth of data that can be used to estimate how market participants view the market fundamentals such as inflow, demand, and thermoelectric supply.

Underlying any computation of the equilibrium value of water is a behavioral assumption about market structure. We develop a model that maps the multiple distributions of market fundamentals into price, output and reservoir distributions as a function of the market structure. Dynamic models of imperfect competition are often hampered by the curse of dimensionality, because the number of state variables typically increases in the number of players. In many applications, the computation time required to solve the model grows exponentially in the number of state variables. We circumvent this problem by adopting a dominant agent framework, which allows us to represent in principle any degree of market power without significantly expanding the state space. This computational tractability allows us to estimate the market structure that best depicts the observed market behavior. The approach is not specific to the Nordic market and could be applied to storable-good markets and electricity markets with hydro technologies more generally.

To warrant the quest for market power, we begin by showing that the actual market behavior does exhibit patterns that are not consistent with socially optimal hydro allocation. For this end, and to obtain a realistic benchmark for our market power analysis, we first develop an aggregative model of competitive storage. The key inputs of the model, including the weekly distributions of inflow and demand and the supply curves of the thermal sector, are estimated outside of the dynamic model from historical data. Hydro demand is then constructed as a residual using the consumer demand and non-hydro supply curve. In this procedure, we must estimate how the non-hydro capacity is supplied in each potential future state of the market; otherwise one cannot form expectations determining the value of the current storage. This is an important difference to the past studies based on expert data sets on marginal cost curves.

Using the socially optimal policy we can evaluate the historical market experience in 2000-2005, a period over which the economic environment was relatively stable. We find a 7.2 per cent welfare loss, or that the cost of meeting the same demand could have been 621 mill. € lower. Most importantly, we also find a systematic deviation between the socially optimal policy and the market usage of water. In particular, the socially optimal reservoir target levels are systematically different from the observed levels, and the failure to save enough water is shown to have lead to the market shortage of water and the price spike in late 2002.

The model of competitive storage can also be used to map the primitive distributions of market fundamentals and non-hydro supply curves to socially optimal weekly price, output and reservoir distributions. The moment properties of the price distributions reveal that the Nordic market has features of an exhaustible-resource market. About 50 per cent of the annual inflow is concentrated to spring and early summer, leading to a market arbitrage that seeks to use this endowment to equalize expected discounted prices until the next spring. Indeed, the socially optimal expected market price increases at a rate very close to the interest rate throughout the hydrological year, while in the end of the year the price is expected to drop at the arrival of the new allocation. The market has also features of a traditional storage market: favorable demand-inflow realizations lead to storage demand and savings to the next year. Towards the end of the hydrological year weekly price distributions have moment properties familiar to those observed in other storable-commodity markets.

The difference between the actual and the optimal hydro allocation motivates our search for a market structure that can outperform the competitive model in explaining the observed patterns. When developing the model of dynamic imperfect competition, we keep the primitives of the socially optimal framework but change the behavioral assumption: some fraction α of the total reservoir and turbine capacity is assumed to be strategically managed, and the remainder of the hydroelectric generation is competitive. This model is not meant as an accurate representation of the actual market structure, which is considerably more complex. We do not have data detailed enough to map actual firm level capacities into the model, and given the dimensionality of the problem, this approach would render the model intractable. Our dominant firm (or cartel) approach is pushing the computational limits while still being an explicit model of dynamic competition.

The computational problem is caused by the need to evaluate the market expectations of the behavior of the large firm in each possible state. We develop an algorithm for solving this fixed-point problem, and then solve the game through a large backward-induction exercise. By repeatedly solving the game for varying α-values, we find a mapping from primitive distributions plus market structure to weekly price, output and reservoir distributions. To evaluate the model fit of the different market structures, we develop a test statistic based on the Generalized Method of Moments. By incorporating the simulated paths of all the key variables as moment conditions, the test statistic facilitates the search for the best-fitting market share parameter.

We find that the market structure where 30 per cent of the storage capacity is strategically managed provides the best match with the historical data. The result is robust to various forms of data aggregation (weekly, monthly, quarterly, or semi-annual aggregation). To evaluate if some unobserved or mismeasured factors can produce a similar match with the data, we force the competitive behavioral assumption and estimate structurally the best-fitting constraints in the hydro system, the discount rate, and out-of-sample expectations for demand and inflow. Sufficient adjustment of both lower and upper limits on available reservoir capacity can almost match the fit provided by our behavioral assumption, but with a gross deviation from what the data indicates for the available capacity.

How is market power then exercised? Because the dominant firm is required to use all its water at some point in time, the current availability can be reduced by shifting supply to the future, thereby increasing the expected reservoir levels as well as prices and price risk. In addition, any attempt by the dominant firm to influence the price level is at least partly counteracted by the competitive agents, and thus the threat of running out of water in the winter also entails that the competitive agents carry over larger storages of water into the peak season. Sometimes this saving is not enough, though, and the dominant firm is able to profitably withdraw output in the cold season. However, in expected terms the social loss from such behavior is low. The reason for the relatively large loss estimated from the historical data is that the market experienced an inflow shortage in late 2002 that occurs on average once in every 200 years. Such extraordinary events provide a unique opportunity for exercising market power.

1.3 About the thesis

This book is structured as follows. In Chapter 2, we provide an overview of the institutional framework and the market fundamentals that underlie our modeling choices. Chapter 3 discusses the connections between the current research and earlier literature. Particular attention is paid to the well-developed literature on market power in the electricity generation sector, but links to the more general topics of storage and market power and empirical models of dynamic imperfect competition are discussed as well. In Chapter 4, we describe the model of socially optimal hydro use. We explain how this model is calibrated and solved on the computer. In addition, we use the model to demonstrate the difference between the actual market behavior and the socially optimal path. The model is also used to derive some fundamental properties of the power market. In Chapter 5, we develop the alternative market structure that enables us to consider different degrees of market power. We then develop a test statistic and search for the market structure that best describes the actual market behavior. In addition, we analyze the mechanics of market power by looking at how the strategic firms may be able to manipulate price levels. Chapter 6 discusses the robustness of our results by studying whether the observed behavior could be explained by socially optimal hydro use under alternative parameterizations of the model. In Chapter 7, we compute the welfare loss from market power and look at the distribution of profits. The final chapter contains a summary of our findings, and a discussion on the possible shortcomings of the modeling approach. The Appendix provides an overview of the many computational issues involved in this research.

The main models presented in this thesis are based on an earlier working paper

(Kauppi and Liski, 2008). The data and program files referred to in this book are available from the author by request.

Chapter 2

The Nordic Power Market

In this chapter, we will discuss the history and current institutions of the Nordic electricity market as they pertain to the market power issue. Concern over the influence of the large firms has been ubiquitous since the market's inception. The current state of the market reflects the regulatory process that has tried to steer the market into a more competitive direction. Below, this process is discussed in more detail. In addition, the discussion here will provide important background information about our modeling choices.

2.1 History of deregulation

The electricity industry has four main functions: generation, transmission, distribution and retailing. Generation involves the transformation of energy stored in another form into electrical energy. Hydro power, for example, is generated by the kinetic energy of water falling through a turbine. Often, generation is located far from the point where electricity is actually consumed. In the Nordic countries a large fraction of total demand is located in the densely populated southern parts of the countries, while much of the hydroelectric resources are located in the north. Transmission involves the transportation of electricity from the generators to the distribution centers at a high voltage. Distribution to the end-users takes place through a local network of wires and transformers at a lower voltage. Retailing, the actual business of acquiring power and selling it to the consumer, is often bundled with distribution.

For a long time, the electricity industry was thought of as a natural monopoly, and often all four supply functions were vertically integrated in public or private monopolies, which were subject to government regulation. A natural monopoly is loosely defined as an industry, where the cost of meeting demand by one firm is less than the cost incurred by several firms. It was believed that the efficient scale of operation in the generation sector favored large generation units. This view was later challenged by studies that showed that generation did not necessarily exhibit increasing returns to scale (e.g. Christensen and Greene 1976, Joskow 1987). These findings gave support to the view that the generation sector could be opened for competition.[1] The transmission and distribution networks are still to a large extent seen as natural monopolies, because the duplication of the existing networks would be prohibitively costly. Expansion of existing grids by individual firms would also be complicated due to the laws of physics, since flows on a given line affect the flows on the other lines with which it is interconnected. Retailing, on the other hand, does not have features of a natural monopoly as long as retailing firms are able to buy power from the generators and have access to the distribution networks.

[1] However, there are important complementarities between generation and transmission. Vertical integration of generation and transmission internalizes the operating and investment complementarities between these two supply functions, which explains the evolution of the vertically integrated market structure in many countries (see Joskow 1997).

Before deregulation, the national Nordic transmission grids (except for Denmark) were owned by the vertically integrated large state-owned power companies. State-owned firms also had a large fraction of total generation assets in Sweden and Finland, and to a lesser degree in Norway.[2] A significant amount of generation assets was owned by firms in power intensive industries, such as steel, aluminum and paper. In Finland, large industrial electricity customers also owned a parallel power grid. The distribution networks were primarily owned and operated by local municipal or cooperative utilities, many of which also generated at least a part of their sales.

The basic formula for electricity sector restructuring has in most countries been to unbundle the vertically integrated incumbents and to open the generation and retail sectors for competition. Thus, in the Nordic countries, the large state-owned companies were divested of their transmission grid assets, which were assigned to new state-owned system operators. In Finland, the separation has not been perfect, though, with generating companies Fortum and PVO both owning 25 per cent shares of the system operator, Fingrid. In the retailing sector, competition was fostered by enabling consumers to freely choose their supplier. The local distribution monopolies are required to charge the same fee for the distribution service regardless of the supplier.

The Nordic wholesale market for generation grew into its current form gradually through a series of steps in the 1990s. Norway was the first Nordic country to open the generation sector for competition in 1991. The deregulation of the Swedish power market in 1996 was immediately followed by integration with the Norwegian market. This market

[2] The Danish system was quite different from the other countries in that all assets were owned by municipal or cooperative retail distributors. Also, the Danish transmission grid was divided into two separate geographical areas. The utilities owned the central coordinating boards (ELSAM and Elkraft), which operated the generation and transmission systems.

integration lead to the birth of the world's first international power exchange, Nord Pool ASA, on January 1, 1996. Initially, Denmark and Finland only had one participant each in the Nord Pool. During 1996, a power exchange, EL-EX, was also established in Finland, and in June 1998, the Finnish market was integrated into the Nordic system. The Western Denmark price area, consisting of the Jutland peninsula and the island of Funen, joined the market in 1999. The market reached its current basic shape on October 1, 2000, when Eastern Denmark was integrated as well. It is now the third largest electricity market in Europe.[3]

The main motivation behind the deregulation of the national markets was to increase efficiency in generation through competition and to encourage investment in new generation capacity. The integration of the national markets into a Nordic market was driven by the argument that the different mixes of production technologies would be highly complementary when market participants would be able to trade freely across the borders.[4] In general, integrating electricity markets is seen to reduce price variation, as long as the variation in demand and supply differ between the two systems. Especially in electricity markets dominated by thermoelectric generators, this reduction in variability may also lead to considerable cost savings. This is due to the fact that at peak demand, power is produced by high marginal cost units. On the other hand, during low demand periods, power generated by low variable cost base-load plants cannot be stored. When demand fluctuation

[3] The largest European electricity sector is in Germany with a total electricity demand of 563.5 TWh in 2005, followed by France (482.4 TWh), the Nordic market (393 TWh), and the UK market (386.6 TWh) (www.eurelectric.org).

[4] It should also be noted that the Nordic countries (including Iceland) have a long history of cooperation due to the cultural and historical ties between the countries. The Nordic Council and the Nordic Council of Ministers, forums of governmental cooperation, were established in 1952 and 1971, respectively. The Council of Ministers also includes formal cooperation in the field of energy policy.

in the two systems is not perfectly correlated, trade enables substituting power from the otherwise idle lower cost plants for the more expensive capacity.

In hydro-based systems, energy may be stored in the reservoirs, and released during peak hours at low cost. Consequently, in the Nordic area, there is very little fossil-fueled peaking capacity. Given that the Finnish and Danish markets were largely dominated by thermal generation, the integration with the hydro-intensive Norwegian-Swedish market held the potential for a significant reduction in price levels.[5] At the same time, the more reliant a market is on hydro power, the larger the effect of inflow variation on market prices. The integration of the Nordic market meant also that in times of inflow scarcity, thermal power could be substituted for hydro.

The restructuring of the national markets left each of the countries with a dominant state-owned generating company. For example, in Sweden, Vattenfall had an approximate market share of 50 per cent, with the second largest company, Sydkraft, holding a 25 per cent share. Instead of forcing the large companies to divest some of their generation, as was done in the United Kingdom following deregulation, the Nordic solution was to dilute the market power by integrating the markets.[6] Nevertheless, ownership concentration at the local level is still high, which may temporarily give the dominant producers high levels of market power, when transmission into the area is congested.

[5] von der Fehr and Sandsbråten (1997) study the gains from trade between hydro and thermal systems in an analytical framework.

[6] See Amundsen et al. (1999) and Amundsen and Bergman (2002) for discussion.

2.2 Nord Pool

Wholesale electricity trade is organized through Nord Pool, a power exchange owned by the national transmission system operators. Market participants submit quantity-price schedules to the day-ahead hourly market, called the Elspot. More specifically, a firm can bid a step-wise price-quantity schedule for each hour of the next day.[7] The day-ahead Elspot market is the relevant spot market. While there is a real-time market (Elbas) closing an hour before delivery, volumes in the Elbas market are small relative to the Elspot (0.6 per cent in 2007). In Elspot, the demand and supply bids are aggregated, and the hourly clearing price is called the system price. The Nordic market uses a zonal pricing system, in which the market is divided into separate price (or bidding) areas. If the delivery commitments at the system price lead to transmission congestion, separate price areas are established. Sweden, Finland, Eastern Denmark and Western Denmark are permanent price areas, but in Norway the transmission system operator uses zonal pricing to manage transmission congestion within the country. Usually there are just two Norwegian price areas, however. In the other countries, the system operator uses counter-purchases to deal with internal transmission congestion. A counter-purchase entails paying a producer to increase or reduce scheduled production. Since 2005, the Nord Pool market has also included the Kontek bidding area in Germany.

Unlike for example the Pool in England and Wales, Nord Pool is a voluntary

[7] In addition to the basic hourly bid, participants can also submit block bids, which is an aggregate bid for several consecutive hours. A block bid must be accepted in its entirety. Whether or not the block bid is accepted depends on the average Elspot price over the hours in question. Block bids are useful in cases when ramping up or down the power plant (or scaling consumption) is costly. Firms can also bid flexible hourly bids, which are bids for an unspecified single hour. The bid will be accepted in the hour, when the price is highest. It is thought to be mainly used by industrial customers that want to sell power back to the market when scaling back industrial production.

market. The share of electricity trade that takes place through Nord Pool has grown over the years. In 2007, close to 70 per cent of total electricity consumption was traded in Elspot. The rest of the electricity trade is conducted by bilateral contracts. Nord Pool also operates financial markets, in which participants can hedge against price risk by trading in futures, forwards, European options and contracts for difference. The Elspot system price is a reference price for both the financial markets and the bilateral trade. The existence of a forward market is typically seen to reduce market power, because firms that have sold some of their output forward have less incentive to manipulate prices on the spot market (see Allaz and Vila, 1993). However, Liski and Montero (2006) show that forward trading can also facilitate tacit collusion. This is because the contracted sales reduce the demand that the deviating firm can capture, and thus make deviation from collusion less attractive. At the same time, the punishment from deviation is as harsh as without forward trading. In the theoretical model at least, the anti-competitive effect is shown to dominate the pro-competitive effect. However, in the actual market, the situation is complicated by the vertical integration of producers and retailers and by regulatory load-serving obligations.

2.3 Production capacities

The attraction of a joint Nordic power market is due to the favorable mix of generation technologies resulting from the integration of the national markets. Roughly one half of annual Nordic generation is produced by hydro plants. In 2000-05, 61 per cent of hydroelectricity was generated in Norway and 33 per cent in Sweden.[8] Sweden is the

[8]The capacities cited here are reported by the Organisation for the Nordic Transmission System Operators (www.nordel.org) unless otherwise noted.

largest producer of thermoelectricity with a share of 46 per cent of the total Nordic thermal output, followed by Finland and Denmark, with shares of 35 and 19 per cent, respectively. The direction of trade between the countries varies from year to year, depending mainly on the availability of hydroelectricity. In years of high precipitation, hydro power is exported from the hydro dominated regions to Denmark and Finland. In these years, a sizeable fraction of total thermal capacity is idle through much of the year. When inflow is scarce, the flow of trade is reversed, and power is exported from the thermally intensive regions to Norway.

Hydro availability is the one single market fundamental that would alone cause considerable price volatility within and across the years even without other sources of uncertainty. Figure 2.1 depicts the mean and the empirical support for aggregate weekly inflow over the years 1980-1999.[9] The mean annual inflow in the market area was 201 TWh of energy, and the maximum deviation from this -49 TWh in 1996. This difference translates into a value of ca. 1.3 billion € using the average system price in 2000-05.

Within-the-year seasonal inflows follow a certain well-known pattern, as illustrated by Figure 2.1. The hydrological year can be seen to start in spring when expected inflows are large due to the melting of snow; on average 50 per cent of annual inflow arrives in the three months following week 18. The aggregate reservoir capacity in the market is 121 TWh, or 60 per cent of average annual inflow. There are several hundred hydro power stations in the market area, with a great variety of plant types. At one extreme, the run-of-river power plants have no storage capacity, and usually produce as much electricity as the current river

[9]The sources for the inflow data are: Norwegian Water Resources and Energy Directorate (www.nve.no), Swedenergy (www.svenskenergi.se) and Finland's environmental administration (www.ymparisto.fi).

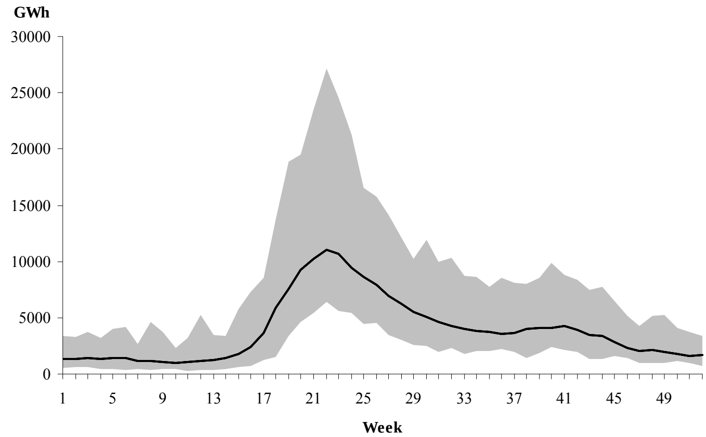

Figure 2.1: Inflow energy in the Nordic market area in 1980-99

flow permits. At the other extreme, there are power stations connected with one or more large reservoirs that may take months to fill or empty. In 2005, the total turbine capacity of the hydro plants was 47 445 MW, or 72% of peak demand. Hydro production is also constrained by environmental river flow constraints. These constraints together with the must-run nature of the run-of-river plants bound the hydro output from below.

For our empirical application, it is important to emphasize the following features of the hydro system. First, there is an almost deterministic inflow peak in the spring: in our historical data, the spring inflow has never been less than one third of the mean annual inflow. In this sense, at the start of each hydrological year, the market receives a reasonably large recurrent water allocation that must be depleted gradually. The annual consumption of this exhaustible resource has marked implications for the equilibrium price expectations, as we will explicate. Second, the remaining annual inflow, on average 50 per cent, is learned gradually over the course of the fall and winter. This uncertainty is important for the storage dynamics over the years: abundant fall inflow, for example, can lead to storage demand and savings to the next year; in case of shortage, a drawdown of stocks can take place. The Nordic market for water can be seen, on one hand, as an exhaustible-resource market and, on the other, as a storage market for a reproducible good. For understanding the potential for market power, it is important to understand these two interpretations, as we will see. Third, the reservoir, turbine, and various flow constraints for production affect the degree of flexibility in using the overall hydro resource. We take an estimate for these constraints from the data and previous studies, but we also structurally estimate the set of constraints best fitting the data (see Chapter 6). The purpose of this procedure is to distinguish the effect of potentially mismeasured constraints on the equilibrium from the effect of potential market power.

In the Nordic area, the non-hydro production capacity consists mainly of nuclear, thermal (coal-, gas-, and oil-fired plants) and wind power. There are three nuclear plants (with a total of ten reactors) in Sweden and two (four reactors) in Finland. Interestingly, the utilization rate of the nuclear plants differs markedly in the two countries. According to the consulting firm EME Analys (see Olausson and Fagerholm 2008), in 1996-2006, the Swedish nuclear plants produced on average at 80.6 per cent of full capacity, while in Finland the utilization rate was 93.8 per cent. Several explanations have been put forward to explain the difference. Among the more interesting theories is the claim that the Finnish safety regulation is less strict than in Sweden, which would allow faster maintenance of the

	Denmark	Finland	Norway	Sweden
Total generation	37.3	73.4	125.2	146.5
Hydro power	0.0	12.7	124.1	67.8
Other renewable power	5.8	2.0	0.3	1.9
Thermal power	31.5	58.8	0.8	76.7
Nuclear power	0.0	21.8	0.0	66.6
CHP, district heating	29.4	26.3	0.1	5.8
CHP, industry	2.1	10.7	0.4	4.3
Gas turbines, etc.	0.0	0.0	0.3	0.0

Table 2.1: Average production (TWh) by technology

plants. Secondly, it has been suggested that the Finnish nuclear safety authority is simply more efficient than its Swedish counterpart. Finally, the fact that the Swedish plants are controlled by the large Vattenfall and E.ON has raised concerns about strategic withholding of nuclear capacity. In any case, the difference in the Swedish and Finnish utilization rates corresponds to about 10 TWh of power, or the equivalent of an entire new nuclear plant, on annual level.

An important part of thermal capacity is combined heat and power (CHP) plants which primarily serve local demand for heating but also generate power for industrial processes and cost-efficient electricity as a side product. An implication of CHP capacity is that the non-hydro market supply experiences temperature-related seasonal shifts, which we seek to capture in our estimation procedure detailed later. Table 2.1 provides a breakdown of average annual total output by capacity type over the period 2000-2005. At the market level, there is thus a rich portfolio of capacities with a large number of plants in each category determining a relatively smooth supply function or, alternatively put, a smooth residual demand function for hydro.

The elasticity of this residual demand is almost exclusively determined by the slope of the non-hydro supply curve because the consumer demand is insensitive to short-run price changes. For this reason, in the analysis we will take the consumer demand as a given draw from a week-specific distribution that we estimate from the data. The industrial consumers have more flexibility in responding to short-run price changes, but their own generation capacity is included as part of the overall market supply curve and, therefore, their price responsiveness is accounted for.

Investment in the generation sector has been scarce in the years of the deregulated market. In particular, following a period of rapid expansion just before deregulation, virtually no new hydroelectric capacity has been built. Some new hydro capacity has been added by upgrading existing facilities. The construction of hydroelectric plants is capital intensive, and the lack of investment has been attributed to the relatively low market price of electricity. Also, hydroelectric projects are often highly controversial politically because of the environmental impacts of dam construction.[10] In Norway, hydro investment is also discouraged by the law, which requires that the ownership of a hydro plant is returned to the state after a 60 year period. Municipal and state-owned plants are exempt from this law.

As for thermal power, in Sweden, there has been a downward trend in thermal capacity. This has been mainly due to the decommissioning of the two 600 MW reactors of the Barsebäck nuclear plant. Barsebäck 1 was closed in 1999 and Barsebäck 2 in the end of 2005. The shutting down of Barsebäck was part of a phase-down plan, made in 1980 in the wake of the Three Mile Island accident, the original goal of which was to decommission

[10] In Finland, this has been best exemplified by the Vuotos-project, a plan to build a large new reservoir on river Kemijoki. After a 30-year battle between the power industry and the nature conservation movement, the Supreme Administrative Court ruled against the project in 2002. Since then, there have been renewed calls for overturning the decision, partly based on concerns about market power in the electricity market.

all Swedish nuclear plants by 2010. This plan has been put on hold, however, and the current trend is on the contrary to invest in the existing facilities to prolong their lifetime. In Finland, capacity has been fairly static over the deregulated period, but currently a new 1600 MW nuclear reactor is being constructed by TVO, in which large Finnish industrial consumers have a large ownership share. The construction of the plant has been delayed, but it is expected to be online in 2011-12. There are also several competing plans for what would be the sixth nuclear reactor in Finland. The motivation behind additional nuclear capacity is largely due to tightening emissions regulations and the pending integration of the electricity market to the continental market, where price levels are on average higher than in the Nord Pool area.

While investment in hydro, nuclear, and conventional thermal plants has stalled in the years of the deregulated market, substantial investment has taken place in non-hydro renewable sources of electricity. In particular, 18 per cent of Danish capacity was wind power in 2007, and large wind power projects are in progress or in the planning stage in the other countries, too. The focus on renewables is partly explained by the energy policy of the European Union, which has set a goal of 20 per cent of total energy consumption for renewable sources by 2020. Apart from wind, this initiative has also increased the share of bio-fuels in the total electricity supply. The use of renewables in generation is encouraged by the governments through explicit subsidies and, in Sweden, through a green certificate system.

2.4 Transmission and trade

The Nordic transmission grid is operated by the four national transmission system operators (TSOs). According to the European Commission's energy proposals, EU member countries are required to unbundle the ownership of the TSOs as vertical integration is seen as an obstacle to fostering competition in the power market.[11] The Swedish and Norwegian TSOs are state-owned. The Finnish TSO, Fingrid, is controlled by large power producers Fortum and PVO, which both own 25 per cent of Fingrid. As of 2008, EU legislation requires the Finnish state to acquire a majority share in Fingrid by buying out the producers' shares. Denmark has two separate transmission grids. In our sample period, 2000-05, these grids were operated by the firms Eltra (Western Denmark) and Elkraft (Eastern Denmark), which were both owned by a large number of small customer or municipally owned transmission companies. The two TSOs were subject to profit regulation. Since August 2005, the entire Danish grid has been operated by a state-owned company, Energinet.dk.

As discussed above, Nord Pool uses a zonal price system, in which the prices in different price areas will deviate, if transmission links between the regions become congested. In principle, zonal pricing is an efficient mechanism to handle transmission congestion (see e.g. Schweppe et al. 1988, Hogan 1992). However, once a price area becomes separated from the rest of the market, the local producers may enjoy a considerable amount of market power. Thus, it may also be in the interest of dominant producers to induce transmission congestion into their price area (see Borenstein et al. 2000 and Joskow and Tirole 2000). Johnsen et al. (2004, see also Chapter 3.3 below) study whether Norwegian hydro producers behave

[11] See Pollitt (2007) for a discussion of the pros and cons of vertical integration of TSOs.

Quarter	SE	FI	E-DK	W-DK	NO 1	NO 2
Q1	2.0	2.6	8.2	5.2	1.5	1.7
Q2	7.5	8.1	21.1	6.8	4.0	2.7
Q3	6.2	12.9	24.6	6.5	2.8	4.8
Q4	2.5	4.3	14.9	10.8	1.4	2.1
All	4.6	7.0	17.2	7.5	2.5	2.8

Table 2.2: Average weekly area price deviations (%) from system price

differently when facing a competitive environment vis-à-vis a situation of local monopoly power.

This study focuses primarily on the question of whether large producers of hydroelectricity allocate the water resource inefficiently over the seasons and even across the years. For this end, we have abstracted away from complications arising from transmission constraints. In our model, we make the simplifying assumption that the Nordic market always forms a single price area. In addition, our model is specified at the weekly level, while in reality trade is conducted on an hourly basis. These two assumptions are interlinked, since at the weekly level the area prices move closely together as indicated by Table 2.2, which shows deviations from the system price for the main price areas as percentage departures in weekly averages (Source: Nord Pool). Juselius and Stenbacka (2008) provide a detailed econometric analysis about the degree of integration of the Nordic area prices.

The Nordic power market is connected to Russian, German and Polish networks. Although important, the role of imports and exports is not as significant from a modeling point of view as in, say, the California market. In 2000-05, average annual imports totaled 14.0 TWh, or 3.6 per cent of annual mean consumption, while average exports were 7.8 TWh (2.0 per cent). Net trade varies from year to year, from small net exports to a net import high of 17 TWh in 2003, when reservoir levels in the Nordic area were exceptionally low. In our empirical application, we treat net trade in the same way as all other non-hydro supply.

Most of the imported electricity is generated in Russia and transmitted via the 1 300 MW import link between Finland and Russia. This link is owned and operated by the Finnish transmission system operator, Fingrid. Nordic market participants may make requests for a given fraction of the total import capacity of the line. When the total requested capacity has been calculated, each participant is allocated a share of the line equal to the relative share of her request. To be granted a transmission right, the customer must have a valid contract with a Russian seller of electricity. The transmission right gives the customer a right to import power at the granted capacity for a fixed length of time. Electricity has been more inexpensive in Russia, and the line is used at close to full capacity. The price of transmission is fixed, and is the same for all participants.

Because of the high share of hydro power, prices in the Nordic area tend to be on average lower and less variable than prices in Central Europe. Germany is the largest export country for the Nordic firms, but German electricity is also imported into the Nordic grid. Trade with Germany is conducted via Danish and Swedish interconnectors.[12]

The higher continental electricity prices are a driving force behind the calls for increased transmission capacity between the Nordic area and Central Europe. After years of relative inactivity, transmission investment is currently a very topical issue in the Nordic electricity industry. The national TSOs coordinate their investment plans through the Or-

[12]The capacity on the Danish links is auctioned by the transmission system operator. The Swedish transmission link is owned by Baltic Cable AB, which is in turn owned by power producers E.ON and Statkraft.

ganization for Nordic Transmission System Operators (Nordel). In 2004, Nordel identified five prioritized internal interconnections; a decision supported by the competition authorities as a remedy for regional market power problems. These projects are currently at various stages of implementation. The current Nordic Grid Master Plan, published in 2008, discusses several potential new transmission lines between the continent and the southern part of the Nordic market. This development is particularly favored by the power industry, which would obviously gain from the increased export capacity. For the electricity customers, further integration with the continent will mean increasing retail prices.

2.5 Demand

Like hydro inflow, the overall electricity demand also follows a seasonal pattern, which is closely temperature related. Figure 2.2 depicts the mean demand and empirical support over the weeks of years 2000-2005. Total net consumption was relatively stable over 2000-05. Electricity demand typically follows economic growth, and over longer historical periods it exhibits a distinct increasing trend. The relatively small changes in total demand over 2000-05 are explained by year-to-year variation in temperatures, and by some idiosyncratic demand shocks, such as a six-week strike in the energy-intensive Finnish paper and pulp industry in 2005. In the longer run, demand is also responsive to the price of electricity, and the exceptional inflow shock of 2002 may have decreased consumption in the latter years of the sample period through the increased value of water.[13]

The short-run price-elasticity of electricity demand is typically very low. In most

[13] Reiss and White (2008) study the demand effects of the California price crisis using electricity billing data for 70 000 households in San Diego. They also focus on the influence of public appeals to conserve energy.

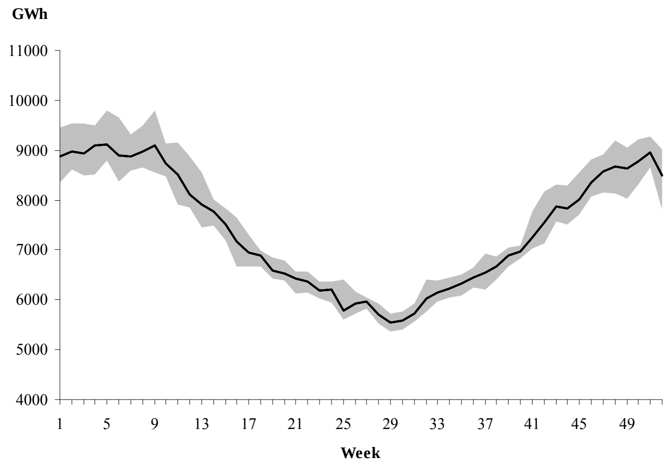

Figure 2.2: Weekly mean and empirical support of demand for electricity in 2000-05

electricity markets, the prices that end-users actually face seldom reflect the fluctuations in wholesale prices. This absence of real-time pricing has important implications for the functioning of the market. Firstly, it increases the need for generation capacity, because if demand does not adjust, insufficient capacity will lead to forced outages, which are extremely costly. Secondly, the inflexibility of demand renders the market more vulnerable to the exercise of market power. In principle, low demand elasticity combined with a step-wise increasing supply function means that even small producers may be able to have a significant influence on market price.

Table 2.3 breaks down the total electricity consumption in 2000-05 by consumer type.[14] Industry is the largest source of consumption in all the Nordic countries except in Denmark. Norway has the highest electricity consumption per capita, owing partly to

[14]In the Table, net consumption equals total consumption minus transmission losses.

	Denmark	Finland	Norway	Sweden	Total
Industry	9.9	45.3	47.2	59.6	162.1
Housing	9.5	20.0	35.7	41.7	107.0
Trade and services	10.5	14.3	23.0	26.3	74.1
Other	3.0	0.9	1.6	6.8	12.2
Net consumption	33.0	80.4	107.6	134.4	355.4
Total consumption	35.3	83.5	122.2	147.5	388.6

Table 2.3: Demand by consumer type in 2000-05

the energy-intensive manufacture of aluminum. In the residential sector, electrical heating contributes to the responsiveness of demand to variations in temperature. Electrical boilers are particularly common in Sweden and Norway, where electricity has historically been inexpensive due to the high share of low-cost hydro power. In Finland and Denmark, district heating has a larger role. In these countries, roughly 80 per cent of district heat is cogenerated with electricity.

Estimating the price-elasticity of electricity demand is a challenging task. The basic issue is the standard simultaneous equation problem: because both demand and supply shift in time, one needs to identify the actual changes in demand from movements along the demand curve. Identification is then based on factors that are known to cause shifts in demand and supply. The task is made more difficult by dynamics in both demand and supply, and by regional heterogeneity. The economist is faced with the question of defining what the relevant time period and geographical market are. In the Nordic market, Johnsen (2001) estimates elasticities using weekly Norwegian data, while Bye and Hansen (2008) look at Norwegian and Swedish price elasticities at an hourly level. The results are somewhat mixed. Johnsen reports weekly price-elasticities between -.05 and -.35, with no clear seasonal pattern, although the elasticity is found to be larger, the higher the price

Company	Output (TWh)	Market share
Vattenfall	75.2	19%
Fortum	60.6	16%
Statkraft	44.8	12%
Sydkraft	33.2	8%
TVO	15.1	4%

Table 2.4: The largest producers in 2001

level. Bye and Hansen find support for inelastic hourly demand in the summer and low demand elasticity (in the range of -.02) in the winter.

2.6 Market concentration

Before restructuring, each Nordic country had a dominant vertically integrated utility. As a result of the restructuring, these firms were split into separate transmission and generation entities. The resultant generating firms were allowed to hold on to most of their generating assets, and were thus left with a large share of national capacity. Although the market has since seen significant merger and acquisitions activity, the original national champions still hold large market shares. Table 2.4 presents the five largest Nordic power producers in 2001 as reported by the Nordic competition authorities (2003).[15] The market shares are computed based on the firm's share of total electricity production.

Apart from TVO, each of the largest five firms owns hydro capacity. Vattenfall, Fortum and Sydkraft all produced roughly 40 per cent of their total Nordic generation by hydro. Statkraft's capacity was fully hydroelectric. In our market power model, presented in

[15]The measurement of market shares is complicated by the prevalence of cross-ownership of both firms and power plants. The figures take into account ownership shares in firms that do not belong to the 15 largest firms. It is assumed that jointly owned generation is allocated in proportion to the ownership shares. The largest firms also have significant cross-ownerships that increase the effective concentration levels, see the report by the Nordic competition authorities (2003) for discussion.

Chapter 5 below, we study a market structure, where a given fraction of total hydro output is owned by a strategic agent (a single firm or a collusive group of firms). Consequently, it is of empirical interest to look separately at the concentration of hydro ownership (in 2001). Statkraft and its partners produced a total of 58 TWh (26.4% of total Nordic hydro generation) by hydro. Vattenfall reported its total hydro output as 38.9 TWh (17.7%), some of which was allocated to minority shareholders. Fortum's total hydro output was 17 TWh (7.8%) and Sydkraft's 13.2 TWh (6.0%). Thus, although the ownership of the Norwegian hydro power is relatively fragmented, the largest firms in the Nordic market control a significant fraction of total hydro resources.

Since 2001, several relatively small acquisitions have taken place, and it is beyond the scope of this thesis to give a comprehensive treatment of the changes in the market structure. Among the more significant changes was the entry of the German producer E.ON, which acquired a majority share of Swedish Sydkraft in 2001. Increasingly, the large Nordic producers have also expanded their operations by acquiring generation capacity both in the other Nordic countries and outside the Nordic market in other Northern European markets.

The prevalence of public ownership is a distinguishing feature of the Nordic market. In all of the four countries, the state has retained a significant ownership share in the formerly vertically integrated producer. In addition, in Norway, municipalities and county councils own approximately half of the production capacity. In Finland and Denmark, municipal ownership of combined heat and power plants is particularly common. In recent years, however, there has been a trend towards private ownership. In particular, locally owned public power companies have been transformed into limited liability companies. At the same time, foreign ownership of generation capacity has increased. The question of whether public ownership reduces market power is open to debate.

For the current research, it is important to note that while the largest producers, Vattenfall, Fortum and Statkraft, are all at least partly state-owned, their management is still highly incentivized to maximize profits. Indeed, the large profits of the state-owned producers and the lucrative financial rewards of the executives of these firms have sometimes been mistaken for signs of market power. While some of these profits may have been the result of price manipulation, the main reason for them is the fact that the generating capacity of these firms consists mainly of low-cost nuclear and hydro power plants. These plants have been built years before the deregulation, and transferred to the firms as a result of the regulatory reform. Because the investments have been paid off, and the variable costs are very low, these plants have become very profitable. Thus, the relevant question is how the executives should be compensated for operating these plants.

Joint ownership of power plants is very common especially in Norway, where the dominant producer, Statkraft, has ownership shares in a number of plants. In all, approximately 30 per cent of Norwegian capacity was jointly owned in 2001 by two or more companies (Nordic competition authorities 2003). Another prominent example of joint ownership is the case of Swedish nuclear plants, which are all jointly owned by the largest Swedish producers. Joint ownership is a potential threat to competition, because it may facilitate exchange of information about the firms' production plans. In 2006, concerns about collusive behavior facilitated through joint ownership lead the Swedish Competition

Authority to investigate the behavior of the owners of the Swedish nuclear plants. The regulator found that the firms had engaged in meetings, where sensitive information about the utilization of the plants was shared. No legal action was taken, however (see Nordic competition authorities 2007 for discussion).

2.7 Regulation

The Nordic electricity market is regulated by the national authorities and, in addition, trade at Nord Pool is regulated by the power exchange itself. Nord Pool is incorporated in Norway, and operates under Norwegian law. The license under which Nord Pool operates requires that the power exchange maintains a market surveillance function. Trade at Nord Pool is voluntary, and participants agree to follow the rules set out in the Rulebook. The Rulebook contains, among other things, regulation regarding the exercise of market power. The Rulebook also contains rules regarding the use of insider information, defined as any information that is likely to influence the price of a Nord Pool product. The surveillance department reports breaches of the rules to a disciplinary committee. Nord Pool can issue warnings and impose financial penalties on participants that are found to have breached the rules. Although the rules fall under private law, they essentially fulfill requirements of the Exchange Act, and thus the supervision by Nord Pool extends to compliance with statutory requirements (see Wasenden 2005, pp. 68).

A detailed discussion of the role of the national competition authorities is beyond the scope of this text. In short, each country has an energy market authority and a competition authority. The exact division of labor between the two authorities varies from country to country. Sometimes the responsibilities of the two authorities overlap. For example, in Finland, the Competition Authority and the Energy Market Authority collaborate closely on energy market supervision. However, the Competition Authority is responsible for both merger control and for monitoring the abuse of dominant position. The financial electricity trade is supervised by the national financial supervisory authorities.

There have been a few competition cases concerning abuse of dominant position to date. The most significant of these took place in Denmark, where the Danish Competition Authority found Elsam guilty of price manipulation on two different occasions. In the first case, concerning a period in 2003-04, Elsam was found to have taken advantage of its dominant position in Western Denmark in 900 hours during which imports into the price area were constrained by transmission congestion. As a consequence, the Competition Authority imposed certain conditions on Elsam's bidding strategies in Nord Pool. According to the Competition Authority, when these conditions were lifted, Elsam again bid excessively high in 1 484 hours during 2005-06. There is an ongoing class action suit against Elsam and DONG Energy, the successor of Elsam. The class action suit has more than one thousand claimants, and it is coordinated by four Danish electricity retailers.[16] The Elsam case is studied in detail by Christensen, Jensen and Molgaard (2007), who find support for the hypothesis that Elsam also manipulated the forward market to disguise its market power in the spot market.

Abuse of dominant position is difficult to show in the case of a hydro producer, because it would entail estimating the value of water. However, the Norwegian Competition Authority expressed its concern about the strengthening of Statkraft's position by ruling

[16] See www.elmarkedsmisbrug.dk for more information.

against the proposed acquisition of Agder Energi and Trondheim Energiverk in 2002. However, the acquisitions were later approved by the Ministry of Labour and Administration on certain conditions, including the requirement that Statkraft sell some of its shares in other hydro firms. Such concessions have been used in other merger cases as well.

The electricity sector is also subject to various forms of environmental regulation. In particular, the EU Emissions Trading Scheme has increased the variable costs of thermal generating plants. The first phase of the program took place in 2005-07, and thus also affects the cost structure in our sample period. Besides causing an upward shift in the aggregate supply function of the thermal sector, it could also be argued that since this effect could be anticipated before the start of actual emissions trading, it might have been reflected in the storage behavior of the hydro producers even earlier. Norway, which does not belong to the EU, has established its own CO2 trading scheme, which also began in 2005. Besides the CO2 trading schemes, the Nordic countries also charge an environmental tax on electricity production. In Sweden, there has also been a system for trading so-called green certificates since May 2003. Green certificates are granted to producers of renewable electricity. The demand for these certificates is created by requiring retailers to buy a certain amount of renewable electricity. In the other countries, the production of renewable electricity is supported more directly by various subsidies.

Chapter 3

Literature

This research is related to several fields of economics. We start by reviewing the empirical literature on market power in the electricity industry, including the relatively scarce body of work on the Nordic power market. We also discuss the literature on imperfect competition in hydro-based power systems. Despite the central role of hydro power in this thesis, we limit our interest to its role in the pricing of electricity.[1] Our approach to measuring market power is a novel one, and methodologically closely related to the empirical literature on structural dynamic models. The storability of the hydroelectric resource, on the other hand, connects the study at hand to the literature on commodity storage.

Market power analysis is usually first called upon already before the deregulation of an electricity sector. In many markets, such as the British market, restructuring entailed also the privatization of public utilities. As part of the privatization, the regulator had to commit to a market design, an important determinant of which was the allocation of

[1] Other research topics in hydropower economics include e.g. the environmental, recreational and agricultural value of water resources. In addition, there is a large power systems engineering literature on the optimal operation of (possibly interconnected) multiple reservoir systems.

capacities to the newly-created firms. In Britain, for example, the power plants formerly controlled by the Central Electricity Generating Board were distributed among three generating companies. One of the key economic questions preceding deregulation was how concentrated the wholesale market should be to ensure efficient pricing while not sacrificing possible economies of scale.

Concentration ratios were and still often are used as an initial tool for measuring potential for market power. The most typical concentration measures include the four firm concentration ratio, measuring the combined market share of the four largest firms, and the Herfindahl-Hirschman index, which is the sum of the squared market shares of all the firms in the industry. The basic idea behind concentration measures is related to the natural link between the size of the firms and their capability to influence market price. Concentration measures suffer from several weaknesses, many of which are particularly evident in the electricity industry. Borenstein et al. (1999) criticize the use of concentration measures primarily on the grounds that in the electricity industry, even small firms may temporarily have a large degree of market power. This is particularly true, when demand is inelastic and the capacity withdrawn by a strategic firm cannot be replaced by a unit with similar variable cost.

More generally, concentration measures give a static picture of the competitiveness of an industry, and provide no information about market performance when some market fundamental changes. In addition, they disregard the fact that firms are asymmetric, and that different firms will react differently to changes in market conditions. Despite these weaknesses, concentration measures are still used as an initial screening device for market power, and are part of the U.S. Department of Justice and Federal Trade Commission horizontal merger guidelines. In 2003, the Nordic competition authorities published a report on competition policy in the Nordic power market that includes, in addition to other analyses, the results of several concentration measure exercises. We discuss the ownership structure of the Nordic market in Chapter 2.6.

Deregulated electricity markets are in many ways ideal case industries for market power analysis. In the first place, electricity is, barring the complications of transmission congestion and area pricing, an ultimate homogenous good. The deregulation of a power market is often accompanied by the establishment of a power exchange, in which a transparent market clearing price for the good is determined. The most straight-forward measure of market power is the price-cost margin, or the ratio between the profit margin and the price, the Lerner index. The computation of price-cost margins requires data that is seen as proprietary in most industries. However, in the electricity industry, the market price is publicly observable, and in many markets detailed data on the costs of generation is also available. The measurement of costs is simplified by the transparency of the generating technologies. For the typical fossil-fuel plant, the variable cost of production consists mostly of the price of fuel, which is easily estimated by the market observers. In addition, one needs to know how efficiently the plant is able to convert fuel into energy. Due to the long history of regulation in the generation sector, researchers have had access to detailed heat rate data in several markets.

The question of how to measure market power in electricity generation revolves around the issue of data availability. The literature on competition in electricity markets is extensive, and it can, to a large degree, be categorized according to the information that has been available to the economist.

3.1 Simulation approach

Before and in the early years of deregulation, when data on actual prices and quantities is scarce, economists typically gauge the potential for market power by simulating market outcomes under different assumptions of strategic behavior. In this approach, detailed information on the cost and capacity characteristics of generating companies is used to calibrate a theoretical model of oligopolistic competition. These models are typically static, and they are simulated under representative demand conditions. The predicted market outcomes are compared with socially optimal behavior. Below, we discuss this approach in more detail, paying specific attention to two seminal papers of the genre. Despite the differences in both the studied markets and the theoretical frameworks, the calibrated simulation models usually share several features. In particular, the economist invariably faces such questions as how to represent market fundamentals such as demand or aggregate marginal costs with sufficient detail. The purpose of the following discussion is to highlight some of these issues and to position our research within the existing literature.

Green and Newbery (1992) studied the British market following its deregulation in 1990. The privatization of the generating sector had entailed the dissolution of vertical integration between transmission and generation, both of which had been controlled by the Central Electricity Generating Board. The transmission grid was assigned to the National Grid Company, owned by twelve Regional Electricity Companies. The generating assets, on the other hand, were distributed among three firms. One of these firms, the Nuclear Electric, was vested all the nuclear power plants. The rest of the generating assets, in total 79% of all generating capacity, were divided between National Power and PowerGen. Because the variable costs of nuclear power are typically below the market price, and due to costs related to ramping up and down a nuclear plant, nuclear power is typically seen as must-run capacity, which cannot be used for strategic withdrawal of capacity. Thus, the British wholesale market was effectively supplied by a duopoly.

The National Grid Company also took the role of the market coordinator by operating the mandatory day-ahead Pool. The generating companies were required to submit price bids for each of their generating units, thus effectively bidding entire price-quantity schedules for the next day. Based on the bids and a demand forecast, the grid company determined for each half hour which plants to dispatch, thus also identifying the marginal unit. All bidders were paid a system marginal price according to the bid of the marginal unit.

Green and Newbery (1992) modeled the market by adopting the supply-function equilibrium concept introduced by Klemperer and Meyer (1989). In the supply-function framework, each firm simultaneously submits a schedule specifying how much power it is willing to supply at different price levels. The obvious advantage of the supply-function model is its resemblance to the actual market mechanism. However, the applicability of the approach has been limited by the difficulty of solving for supply function equilibrium in more complex environments.[2] In Green and Newbery, these difficulties were alleviated

[2]Supply function equilibrium is characterized by a differential equation, the solution of which is greatly aided by the assumption of symmetric firms. However, recent research has derived supply function equilibria analytically under less stringent assumptions about asymmetric costs and capacities. See e.g. Green (1996),

by the simplicity of the market structure in the beginning of the privatization period. The model was calibrated using public, plant-specific data published before the deregulation by the Central Electricity Generating Board. To apply the supply function approach, Green and Newbery had to resort to a few simplifying assumptions about how to represent the costs of generation. The aggregate marginal cost function of an electricity market is typically a step-wise function of the output, but the solution of the supply function equilibrium model required a smooth representation of the marginal costs. The authors also had to deal with the seasonal pattern of forced outages of the plants, and with the costs related to the start-up of peak-load plants. Since both forced outages and start-up costs increase the costs of generating a given amount of electricity, the authors basically adjusted their estimated marginal cost curves upwards. Demand was assumed to be responsive to price, but the slope of the linear demand curves was not estimated from the data. Instead, three alternative values for the slope were used. Also, the model was simulated in three different demand scenarios representing typical conditions for winter, summer and midyear.

Supply function equilibrium consists of a set of supply functions that are profit-maximizing for the oligopolists, given the supply functions of the other players. A range of supply functions may qualify as an equilibrium, and in general the supply schedules lie between the competitive and Cournot supply schedules. Green and Newbery also incorporated capacity constraints on the supply schedules, which limited the range of equilibria. They report the simulation results based on the lowest output equilibrium. Welfare loss was measured as the change in consumer and producer surpluses. Significant potential for market power was found for all three demand elasticity parameters. In the base case, the

Baldick et al. (2004), Holmberg (2007) and (2008) and Wilson (2008).

price of electricity went from 23 £/MWh under marginal cost pricing to 41 £/MWh under duopoly equilibrium. Total deadweight loss was found to be £340 million per year, while the duopoly's utilization rate went from 45 to 37 per cent. The total profit of the two duopolists increased more than four-fold compared to marginal cost pricing. Under more inelastic demand, the price increase and welfare loss were even higher.

Green and Newbery concluded that the potential for market power in the British spot market was alarmingly high, and proceeded to discuss measures that would curtail the duopoly's influence. They also simulated an alternative market structure in which National Power and PowerGen were split into five symmetric producers. The results were supportive of further restructuring: the simulated average price fell to 27 £/MWh and the welfare loss to £20 million. Green and Newbery also discussed the effect of new entrants into the market, and warned of the possibility of excessive new capacity.

Von der Fehr and Harbord (1993) also studied the England and Wales market, but in a theoretical auction framework. In their model, each firm owns a fixed number of capacity-constrained generating units and the marginal cost of a given generating unit is fixed. Firms simultaneously submit price bids for each of their generating units, and these bids are then aggregated by the auctioneer into a market supply curve. Demand is assumed inelastic and there is uncertainty about its level. The units that are dispatched in the equilibrium are paid the bid price of the marginal unit. These characteristics of the model are similar to the actual functioning of the British market, and the auction approach could be described as the most natural description of the market. This realism, however, comes at the cost of difficult empirical implementation. Von der Fehr and Harbord study the actual bid curves of the duopolists under different demand conditions, and compare them to their theoretical predictions. According to their findings, both the theoretical model and the observed bidding behavior support Green and Newbery's result of non-competitive bidding.

Besides the supply function equilibrium concept, the other main approach to simulating oligopoly behavior in power markets has been to model the market as a Cournot game. Instead of submitting actual supply schedules like in the supply function models, Cournot competitors decide simply the total quantity they are willing to produce. While quantity-setting does not provide as accurate a description of actual power exchanges as supply functions, it generally allows a much more detailed calibration of the market in other respects. Borenstein and Bushnell (1999) applied the Cournot approach to the Californian power market. The largest producers were modeled as a Cournot oligopoly, while the smaller generators were supposed to behave as price-takers. In California, the market was dominated by three vertically-integrated investor-owned utilities (IOUs): Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). Before deregulation, the IOUs had regional monopoly over transmission, distribution and generation, and were regulated by the California Public Utilities Commission. The restructuring of the Californian market took effect in April 1998. It entailed the vertical separation of the IOUs' transmission and generating businesses. The operation of the transmission grid was entrusted to a new institution, the California Independent System Operator (CAISO). PG&E and SCE were also required to divest at least half of their fossil-fueled capacity.

Trade in the California wholesale market was organized through California Power

Exchange (PX). The PX operated a day-ahead hourly market, into which the IOUs were required to submit both their supply and demand bids. For other market participants trading in the PX was voluntary. In addition to the PX day-ahead market, there also existed a real-time balancing market operated by CAISO. The system operator also organized markets for operating reserve services.

California's experiment with deregulation ended famously in failure in 2001. The collapse of the market was the result of both defective market design and a combination of adverse changes in the market environment. The reasons and consequences of the California electricity crisis have been discussed in detail in, e.g., Joskow (2001) and Wolak (2005). At the core of the problem were rising wholesale electricity prices which were primarily due to the simultaneous reduction in available capacity and increase in demand. Interestingly for the Nordic case, the tightened capacity situation in California was partly due to two consecutive winters with low hydroelectric production. Apart from the hydro capacity in Northern California, the state typically imports a significant amount of hydro power from the Northwest. The tightness of supply provided some generating companies with the chance of exercising unilateral market power. We will review empirical research on the role of market power in the market's downfall later in this chapter.

The research by Borenstein and Bushnell (1999) was written before the IOUs had divested their assets. The IOUs eventually sold all their generating capacity, and the actual market structure at the start of the restructured market consisted of five large firms rather than three. In this sense, the predictions of the Borenstein and Bushnell simulation model were never really tested in practice. Nevertheless, the paper is a prime example of the Cournot simulation approach. The price-taking fringe was assumed to consist of all other production except the three IOUs, specifically including municipal utilities and smaller independent producers, and the out-of-state firms that exported power into California. Unlike in Green and Newbery (1992), who had to use smooth approximations of supply schedules, Borenstein and Bushnell constructed firm-specific, step-wise marginal cost functions based on actual plant-specific cost data. The marginal cost functions of the Californian firms belonging to the fringe were aggregated into a single supply curve. There are three region-specific supply curves for the out-of-state firms. In the model, California is assumed to be a net importer, and the flow of electricity from the three exporting regions was constrained by the actual transmission capacities. The fringe supply curves are then subtracted from market demand, and the oligopoly is assumed to compete over the resulting residual demand. Demand is assumed to be of constant elasticity form, and it is calibrated using forecasted price-quantity pairs and a range of hypothetical price elasticities.

Borenstein and Bushnell (1999) emphasized the crucial nature of hydro power in the California market. They describe the basic dynamic optimization problem of allocating scarce hydroelectric resources, and also discuss the allocation strategy of an agent with market power. Their framework, however, is static, and the hydro scheduling decision is not built into the model. Instead, they assumed that hydro resources are allocated to the highest demand periods. This “peak-shaving” scheme is assumed to approximate the solution, in which firms allocate water to equalize their marginal revenue over time.

As with most static simulation models, Borenstein and Bushnell (1999) presented their simulation results for a set of representative states of the market. In practice, they calculated the Cournot equilibrium for six different demand scenarios in four months of the year. The Cournot price and the competitive price are used to compute an industry Lerner index. The Lerner index is highest in the peak hour, when the capacity of the price-taking fringe is tight, and the elasticity of the residual demand of the strategic firms is low. At low demand hours, the price cost margin is very small. Borenstein and Bushnell also tested for the sensitivity of their results by exploring the effects of further divestiture of plants by the largest producers and intra-state transmission congestion. They also discussed alternative assumptions about the allocation of hydro power, and noted that the ability of dominant hydro firms to manipulate prices is curtailed by the existence of a hydro fringe. Moreover, Borenstein and Bushnell argued that due to the price arbitrage of the hydro fringe, a more detailed modeling of the hydro sector might yield output predictions significantly different from the peak-shaving strategy, but the price-cost margins would probably not be affected as much.

The Cournot approach has been applied to the Nordic market as well. Andersson and Bergman (1995) analyzed the Swedish power market before its deregulation, and compared the simulated Cournot outcomes of different hypothetical market structures to data from the pre-deregulation period. The Swedish market was highly concentrated due to the dominant position of state-owned Vattenfall, and the simulation results supported the view that too much concentration could lead to price levels exceeding the pre-deregulation levels. The subsequent integration of the Swedish and Norwegian power markets was widely seen to dilute the ability of the largest producers to exercise market power. This development was studied in a Cournot framework by Amundsen, Bergman and Andersson (1998).

At the turn of the millennium, producers engaged in a series of mergers and acquisitions, and the cross-ownership of production capacity gave rise to new concerns about market power. Amundsen and Bergman (2002) applied the Cournot approach to explore the effect of increased concentration in the Norwegian-Swedish market. The three papers on Cournot competition in the Nordic market do not model the storage decision associated with hydro power. Instead, hydro output is constrained only by the firm-specific turbine capacities. In addition, there is a fixed opportunity cost for using water.

3.2 Direct measures of price cost margins

The availability of precise data on the variable costs of generation has enabled economists to compute direct estimates of price-cost margins in electricity markets. These studies can be classified according to whether they focus on market-level or firm-level price-cost margins. The latter approach requires not only data on plant-specific costs but also on firms' supply bids and firm-specific contract positions, since the profit-maximizing strategy of a firm in the spot market depends on its prior commitments in the contract market. We will first discuss two market-level approaches, and then review the work on firm-level margins.

Wolfram (1999) computes direct cost estimates based on the technical characteristics of power plants in the England and Wales market. Her sample consists of half-hourly price and quantity data during an 18 month period in 1992-94. In addition to the direct measure, she sheds light on the usefulness of other methods of assessing market power by comparing those methods with the direct estimates. The direct estimates are based on the fact that the production technology is straight-forward, and – because fuel costs typically account for most of the variable costs of generation – firm-specific variable costs can be estimated with precision given unit heat rates, fuel type and fuel prices. Wolfram constructs the competitive benchmark prices and compares them with the observed market prices. She also compares the direct estimates to estimates based on supply function equilibrium simulation (Green and Newbery 1992) and finds the direct estimates of market power much lower than those based on the equilibrium model. In addition, Wolfram computes estimates of market power based on methods that do not require data on marginal costs. The first method takes advantage of the distortion that a price cap created in the pricing behavior of firms. The second method is the standard approach of identifying an elasticity adjusted markup using comparative statics in demand. The markup estimate is close to zero, but this does not reject the result obtained using direct marginal cost estimates. We discuss this conjectural variations framework in more detail below. Overall, Wolfram finds relatively low levels of market power, and hypothesizes that this may be due to the incumbents' willingness to deter entry by pricing lower or to avoid regulatory intervention.

Borenstein, Bushnell and Wolak (2002) follow the same method as Wolfram (1999) in studying the California market in 1998-2000.[3] The authors construct a competitive market counterfactual and compare it to the observed hourly prices. They find mark-ups to be higher in high-demand summer months and close to competitive in the low-demand months. The percentage margins were highest in the summer of 2000, coinciding with a sharp increase in the costs of fossil-fueled generation. This cost increase was due to a

[3]Joskow and Kahn (2002) and Puller (2007) also provide direct measures of the market-level price-cost margin in the California market and Mansur (2007) in the Pennsylvania-Jersey-Maryland (PJM) market.

combination of rising natural gas prices and higher pollution permit prices. The situation was exacerbated by an increase in demand and a reduction in imports from other states. However, the role of market power was pivotal in the increase of electricity prices. Borenstein et al. estimate that the total electricity expenditures were roughly doubled in the summer of 2000 due to market power.

Recently, many empirical studies of the electricity industry have used firm-level data on actual bids in the spot market. As discussed above, this approach ideally requires also data on the forward market position of the firms. This information has been more difficult for the researchers to access, however. An exception is Wolak (2003), who has data on the contract position of a single Australian firm operating in the Australian National Electricity Market. He studies whether the firm could have operated more profitably using a different hedging strategy, and finds that reductions in the firm's contract position could have significantly increased the mean and standard deviation of variable profits.

Sweeting (2006) studies the England and Wales market in the late 1990's using both the market-level and the firm-level approach and finds that the two largest firms appeared to collude tacitly. In particular, the firms could have earned higher profits by submitting lower bids. Sweeting has data on firm-level bids and costs, but because he cannot observe individual contract positions, he experiments with different levels of contract cover. Measuring market level mark-ups, he finds evidence of considerable market power. Sweeting's findings of increasing market power at the time of falling market concentration cast doubts about the applicability of the oligopoly simulation models in situations when tacit collusion between generators is likely.

An alternative approach to the contract position problem is represented in Hortacsu and Puller (2008), who study the spot market for electricity in Texas. They have firm-specific data on both marginal costs and bids, and are thus able to measure the extent to which firms have actually maximized their profits. They model competition as an auction, where firms bid under uncertainty about future demand and other firms' contract positions, which are assumed to be private information. Hortacsu and Puller infer the contract positions of all firms using data on marginal cost and bidding. They find that large firms in the Texas market do maximize their profit by exercising market power. However, they also find that small firms bid excessively steeply, which is not profit-maximizing for them, but leads to further inefficiency losses. The inability of small firms to bid efficiently is attributed to scale economies in setting up bidding operations.

Finally, Puller (2007) studies the California market from 1998 to 2000 using firm-level data on marginal costs and output (but not on contract positions). He finds that the five dominant firms all withheld output when price exceeded marginal cost. He also estimates the hourly residual demand function of the large players, and constructs three different models of competition: a competitive market, a Cournot model and a model of perfect collusion. Puller finds that the observed prices are very close to prices corresponding to a Cournot equilibrium. In particular, Puller concludes that the price spikes during the California electricity crisis could be attributed to unilateral market power and changes in demand and costs, rather than to tacit collusion between the strategic firms.

3.3 Hydro power economics

The question of optimal intertemporal allocation of hydroelectric resources has a long history in economics and operations research. A comprehensive literature review is beyond the scope of this thesis. However, it may be enlightening to discuss shortly one of the earliest contributions in this literature. Little (1954) studied the problem of optimal water storage policy for a single hydro plant, calibrating his model with data that was representative of the Grand Coulee dam on the Columbia River. Little's thesis is an excellent review of the economic issues of hydro power scheduling. At the time of Little's writing, the Grand Coulee and many other hydro plants were operated according to rule curves. These curves were graphs specifying the recommended level of output as a function of time. This method was based on the principle that following the rule curve would ensure a certain minimum level of production in the hypothetical case of the worst hydrological year recurring. When inflow was more abundant, plant managers would adjust the output accordingly, using the rule curve only as a point of reference. Sometimes rule curves were also computed for median hydrological conditions.

Little's work was an early application of stochastic dynamic programming. In his model, the state variables include the current reservoir level and the level of inflow in the previous period.[4] As in the current work, the optimal policy is designed to minimize the cost of an alternative power source (thermal power). Little specifically makes a distinction between the short-range and long-range problems, emphasizing the importance of inflow uncertainty in the latter case. Little formulates his model as a finite-horizon problem, and

[4]Unlike in the current research, autocorrelation in inflow was particularly important for modeling a single river system. As Little put it (p. 30) "a river will keep flowing a long time even if there is no rain".

solves the model using backward induction. The model was implemented on a computer, being the first numerical application of its kind, and the simulated output was compared to the actual operation of the Grand Coulee. Little found relatively small deviations between the optimal policy rule computed using dynamic programming and traditional rule curves, but attributed this to the dominant role of the river flow in the operation of the dam. He also emphasized that while the theoretically optimal policy would minimize cost over the long-run, this was not necessarily so during a short simulation based on a historical inflow series. For a review of the advances in solving for optimal hydro use policies since Little's thesis, see Lamond and Boukhtouta (1996).

In addition to academic research, there are a large number of commercial or policy-oriented electricity market models. These models range from detailed technical descriptions of certain parts of the electricity system (e.g. the district heating system) to full-scale general equilibrium models, in which the electricity market is only one of the modeled markets. As to the former category, the so-called engineering economic models, several models of this type exist for the Nordic market alone. The major industrial power market model in the Nordic area is the EMPS (known better by its Norwegian name *Samkjöringsmodellen*) developed by the Norwegian research organization SINTEF.[5] There also exist large-scale market power models of the Nordic power market as well, but these models do not solve for the intertemporal water allocation problem.[6]

Of particular interest to the current study is the relatively scarce literature on

[5]Other models include the PoMo (developed by Swedish firms EME Analys and Tentum), VTT-EMM (Technical Research Centre of Finland), ECON Spot (consulting firm Econ Pöyry), and Normod-T (Statistics Norway). See Unger et al. (2006) and Bye and Hope (2006) for details.

[6]Models of this class include the commercial MARS model owned by the Danish TSO energinet.dk, and the open-source Balmorel model.

hydro power and imperfect competition. This literature is mostly theoretical.[7] Crampes and Moreaux (2001) study alternative market structures in a two-period model, where demand elasticities differ between the periods. Their results suggest that hydro firms with market power will benefit from generating less in periods of low demand elasticity, when a small reduction in hydro output can be enough to raise prices significantly. Less production at the peak means that the hydro firms must produce more off-peak. Systematic spilling of water (releasing water without generating electricity) is thought to be observed by the authorities. It will be most profitable to increase generation in the highly elastic off-peak season, when the increase in output will depress prices by only a small amount.

Försund and Hoel (2004) and Hoel (2004) show that the price of electricity in markets with a monopolistic hydro producer may vary in a deterministic setting even if demand is static over time. This is due to the fact that the thermal capacity is constrained. The monopolist maximizes its profit by alternating between low and high production levels, when in the socially optimal case it would produce a constant amount throughout the year. Its average output will be the same as in the competitive case, however, since it has to use all of its water resource by assumption.

A few papers also explicitly consider the important uncertainties of hydro-based power markets. Garcia, Reitzes and Stacchetti (2003) study price competition between hydro duopolists under stochastic inflow over an infinite time horizon. Their focus is on the effect of a price cap. The price cap is shown, among other things, to affect current pricing (and hence storage) behavior by potentially constraining future price levels. Genc and Thille (2008) study an infinite-horizon Cournot game between a hydro and a thermal

[7] In addition to the literature cited here, see also the book on hydropower economics by Försund (2007).

producer. In their model, demand is stochastic, but inflow is not, which implies a steady-state level for water storage. They find that under normal inflow, reservoir levels tend to be higher than under social optimum. The reduction of hydro output is accompanied by a reduction of thermal output (both agents are strategic), and the duopoly price is higher and more volatile than in a competitive market. Genc and Thille also consider the possibility of capacity investments by the thermal producer.

Computational models of imperfect competition in hydro-based markets are scarce. However, Scott and Read (1996) develop a framework for studying a Cournot duopoly using a dual dynamic programming approach. In their basic case, thought to be representative of the New Zealand power sector, a large firm owning all the hydro resources and a single thermal plant faces a large thermal firm and a group of price-taking smaller thermal firms. Scott and Read also consider the effect of exogenously determined levels of physical contracts. Their simulation results suggest that efficiency losses from market power are higher the smaller the level of contracting and the lower the elasticity of demand.

Bushnell (2003) is an exception to the lack of empirically oriented market power papers on hydro-based markets. The author illustrates the hydro generators' incentive of shifting water resources across periods by constructing an oligopoly model, which he calibrates with data from the western U.S. electricity market. The electricity market is modeled as a multiperiod Cournot game with no uncertainty about demand, costs or inflow and the model is solved as a mixed linear complementarity problem. According to Bushnell's findings, the large hydro producers are strongly motivated to manage their reservoirs in a socially suboptimal way. The author focuses on a period of one month, with suppliers deciding on supply on an hour-by-hour basis. Since there is enough variation in demand within a month, Bushnell argues that the hydro utilities are able to spread the excess water within the off-peak hours of a month. In other words, the inefficient shift in water releases does not necessarily happen over the yearly water cycle, but over a time scale less than a month. Bushnell also finds that the incentives of the dominant player with hydro resources, the Bonneville Power Administration, depend on the degree of concentration of the rest of the market.

In markets with nodal or zonal pricing, hydro producers may take advantage of temporary bottlenecks in the transmission network. When imports into the price area are constrained by transmission congestion, the locally dominant hydro producer faces a less elastic residual demand curve. In one of the few empirical studies of market power in the Nordic power market, Johnsen et al. (2004) compare equilibrium prices in periods with different demand elasticities in order to find out if producers hike up prices in low-elasticity periods.[8] The authors also specifically consider regional market power due to transmission constraints. In particular, they consider situations where hydro generators use up water when facing a competitive environment to increase their water values in situations, where transmission constraints give them regional monopoly power. Focusing mostly on five price areas in Norway, they find evidence of market power for one region only. This estimate might be too low because the testing strategy is based on the assumption that transmission

[8] Apart from Johnsen et al. (2004), few papers study competition in the Nordic market with the aid of a formal model. Von der Fehr et al. (2005) discuss the performance of the market during the price crisis in general terms, and conclude that the market withstood the exceptional hydrological shock well, as no rationing measures were needed to overcome the situation. This view is shared by Bye et al. (2006), who argue that the sudden decrease in inflow during the fall of 2002 was more damaging to the market than a larger inflow shortage spread over a longer time period would have been. The authors simulate efficient hydro allocation using a numerical model (Normod-T).

congestion is exogenous to the output choice of the firms. In other words, the authors do not consider the possibility that firms might induce bottlenecks in the transmission grid for strategic reasons.

The approach chosen by Johnsen et al. (2004) circumvents the problem of measuring the shadow price of hydro power by focusing on the hypothesis that hydro firms will take advantage of the variation in the elasticity of demand. Another method which does not require information about the costs of either hydro or thermal power is the conjectural variations framework.[9] A usual application of this econometric approach requires data about market level prices and quantities, and about both demand and supply determinants. The economist also makes functional form assumptions about demand and supply. The firms' first-order condition is written in a form, which is consistent with different market structures. The market power parameter is typically identified through variation in the elasticity of demand (Bresnahan 1982, Lau 1982). The conjectural variations approach has been criticized on several accounts (see Reiss and Wolak 2007 for discussion). Interestingly, the availability of precise marginal cost data has also enabled researchers to study the performance of the conjectural variations approach in electricity markets. Both Wolfram (1999) and Kim and Knittel (2006) show that the approach tends to lead to poor estimates of market power.

The basic conjectural variations model is static, but there also exist dynamic extensions of the model. The dynamic model has been applied to the Nordic market as well (see Fridolfsson and Tangerås 2008 for a review). Given the controversy about the accuracy of the estimates even in simpler applications, we do not discuss this research in

[9]See Bresnahan (1989) and Reiss and Wolak (2007) for details.

more detail. Also, reducing the strategic behavior of hydro firms into a simple, market-level first-order condition yields little information about how market power is actually exercised in hydro-based systems.

3.4 Discussion

There is an evident gap in the literature that the current research aims to reduce. Although there is a well-developed empirical literature studying imperfect competition in the electricity industry, the methods used do not readily extend into hydro-dominated power markets. In this section, we will discuss the links between the approach presented in this thesis and the existing literature. In addition to the earlier research on electricity, we also look at the more general methods developed in empirical industrial organization and the scarce work on market power and storage.

The first step of our approach is to compute the competitive benchmark market outcomes, and to compare them to the actual market data. We estimate the industry primitives from the data, and use them to calibrate our model of social optimum. In this respect, this part of our work has some similarities with the approach of Wolfram (1999) and Borenstein et al. (2002), who measure price-cost margins at the market level by a direct comparison between market price and marginal cost. The main difference is, of course, that the production costs are more difficult to estimate, when a large fraction of output is hydroelectric. In particular, we need to explicitly model the intertemporal hydro allocation problem to solve for the marginal value of water. We are primarily interested in how the water is allocated over longer periods of time, for which purpose it is most natural to work with weekly data. Thus, we do not attempt to compute actual hourly price-cost margins like in the literature cited above, although, in principle, it would be simple to reformulate the model to hourly precision.

However, should we be interested in hourly price-cost margins, we would have to account for several short-lived changes in the market environment that have an impact on prices at the hourly level. Even if such detailed data was available, it would be virtually impossible to incorporate such uncertainties into the dynamic programming framework. The crucial question we ask in our first stage is whether there seems to be a systematic difference between the observed water use and the socially optimal policy. For this purpose, the use of weekly data is a reasonable assumption, especially as the value of water is unlikely to change much within a week.

Our focus on the long-run hydro use also sets us apart from the simulation papers that explicitly model imperfect competition (e.g. Green and Newbery 1992, Borenstein and Bushnell 1999, Puller 2007). Because these papers deal with a static environment, the models are not tested over successive time periods. In fact, doing so would actually require a dynamic approach, because even in absence of hydro power, there are important dynamics on both the demand and supply side of the market at the hourly level. Examples include the costs of ramping up and down both production and load facilities, and the use of block bids in the power auction. Yet, more importantly, we do not only ask from the data whether it is best described by competitive behavior or by a certain model of oligopolistic competition, but specifically estimate the market structure that best fits the data. We introduce a dominant agent framework, which allows us to simulate market outcomes for any degree of market power, ranging from efficient hydro scheduling to a hydro monopoly.[10] Instead of judging the model fit only on the basis of how well it replicates the market price, we develop a GMM-based test statistic, which also takes into account the accuracy of simulated reservoir and output paths.

Modeling the Nordic power market explicitly as a dynamic oligopoly model would be extremely challenging. For example, the well-known Ericson-Pakes (1995) framework cannot be readily extended to a hydro-dominated electricity market. In Ericson and Pakes, pricing (or the output decision) is thought to be a short run decision based on the state of the market. The state, on the other hand, develops through firms' investment, entry and exit decisions. Thus, prices and quantities have no dynamic implications, and the product market equilibrium is completely disconnected from the evolution of the state. This is obviously quite opposite to the current problem, where the reservoir state is controlled by the output decision. Also, in the Nordic power market, entry, exit and investment have not played a large role in recent years.

Although the Ericson-Pakes framework is quite flexible, and has been used to study a variety of industries, the dynamic-static breakdown of the model narrows its applicability in economic phenomena such as storage, learning-by-doing, durable goods and network effects. Explicitly allowing the stage-game equilibrium to affect future choices typically increases the computational complexity of the model. There are few papers that explicitly model oligopolistic dynamic competition of this kind. Benkard (2004) studies learning-by-doing in aircraft manufacturing. In Benkard's model, aircraft manufacturers

[10] Gowrisankaran and Holmes (2004) study mergers within a dynamic dominant agent framework, where the capital stock is determined by investment choices. The dominant firm is assumed to move first both in the product market and in the capital market.

maximize profits by making output, entry and exit decisions. The state of the market consists of aggregate demand, firm-specific experience, product type and product quality. In particular, the cost of producing a given type of airplane depends not only on its type and quality, but on the firm's experience in producing that type. Experience is a function of the firm's past output decisions, and thus there is a link between the product market equilibrium and the evolution of the state. Key market outcomes such as entry, exit, prices, and quantities are endogenously determined in the Markov perfect equilibrium. As in the current research, the market primitives are estimated separately from the computation of the equilibrium. Benkard finds that his computational model represents both prices and the industry dynamics well.

The market structure of the aircraft industry is characterized by a small number of well-known players. In the case of the Nordic power market, there are too many large hydro firms for the market to be explicitly modeled as an oligopoly market. Instead, our goal is to find the market structure within the dominant firm framework which best fits the actual market behavior. This task is facilitated by the relative simplicity (as compared with e.g. the aircraft industry) of measuring the state of the market. First, we are dealing with a homogenous good with almost perfectly inelastic demand. The good is traded on a spot market, the price of which is the reference price for all transactions in electricity. Both price and output by generation type are publicly available information, which enables us to estimate the supply of the thermal sector directly from market data. The key state variable, the current level of reservoirs, is precisely measured and public information to all market participants. There is also a long time-series on the evolution of reservoir levels, making the estimation of state transition probabilities straight-forward.

Some constraints of the hydro power system cannot be similarly represented at the aggregate level, however. In Chapter 6, we study the effect of unmodeled constraints by structurally estimating the parameters of the social planner's model that represent the observed market behavior the best. Yet, analysis exploiting less aggregated information on capacities, usage, and regional heterogeneity is called for. If such data becomes available, one could potentially estimate hydro usage policies directly from the data, and then use the estimated policies to simulate hydro resource values. These values could in principle be used in estimation of structural parameters of the market using, for example, the method developed in Bajari, Benkard and Levin (2007). This approach is called the two-step method of estimating dynamic games. The first-step of the method is to recover the agents' policy functions and the probability distributions governing state transitions. In our context, this would entail regressing water releases on demand conditions and reservoir levels. Because the players' expectations are on average correct, the first state recovers essentially their equilibrium beliefs. The second stage is based on the fact that the agents are assumed to be profit-maximizing. In our model, the observed water releases should be optimal for the given reservoir levels, demand and time of year. This condition can be represented by inequality constraints, where the observed behavior is at least weakly preferred to the other production levels. The model's parameters solve this system of inequalities. For an application of this recent method to environmental regulation, see Ryan (2006).

The current research is also linked to the scarce literature on storage and market power.[11] This literature is almost exclusively theoretic, and typically discusses commodity

[11] There is a well-developed literature on competitive storage: the work by Williams and Wright is summa-

markets as the most likely application for the theory. Newbery (1984) studies the storage policy of a dominant producer and compares it with the monopoly and competitive solutions. McLaren (1999) builds on Newbery to describe a Markov perfect equilibrium in an oligopolistic storage market. He shows that market power leads to lower storage levels and higher price volatility. The effect of market power is shown to be reduced as the number of speculators in the market increases. Rotemberg and Saloner (1989), on the other hand, suggest that higher storage levels could be held to maintain collusion.

The dominant agent framework presented in this thesis could be applied to other markets as well. However, in order to compare the results presented here with the storage literature, it is worthwhile to note a few key differences between typical commodity markets and the market studied in this thesis. First of all, hydro producers are constrained, both in the model and in reality, to use all the inflow, or the stochastic harvest, to produce electricity. Releasing water without generating is thought to be observed by the regulators, and is thus not a viable strategy to increase profits. This has marked implications for the storage behavior, of course. Also, water is not transferable, and cannot be held by speculators.

rized in their book (1991), which also includes a chapter on storage monopoly. See also Deaton and Laroque (1992) and (1996).

Chapter 4

Socially efficient allocation

4.1 The model

We describe now the socially optimal resource allocation problem. This way we introduce the basic elements of the model which, for the most part, remain the same throughout the rest of the thesis.

Time is discrete and extends to infinity, $t = 0, 1, 2, ...$One year consists of 52 discrete time periods. It will be important to keep track of the periods within a year, and therefore we introduce another time index for the week, ω. Let S_t denote the aggregate hydro stock (measured in energy) in the reservoir, x_t is the demand for energy, and ω_t is the week at t. State, denoted by s_t at t, is the vector

$$s_t = (S_t, x_t, \omega_t).$$

The timing of decisions within period t is the following:

1. state s_t is observed;

2. water usage from the stock, denoted by u_t, is chosen;

3. residual demand $z_t = x_t - u_t$ is met by non-hydro production;

4. inflow available at $t+1$ is realized.

In the empirical application the key variables are discrete and defined on a finite grid, and this is what we assume also for the theory model. In particular, the action set $u_t \in U(s_t)$ is finite as well as the possible physical state space for S_t. Choices are constrained, e.g., by the availability of water, reservoir and turbine capacity, and river flow restrictions.

The demand realization is drawn separately for each week from a week-specific distribution:

$$\begin{aligned} x_t &\sim G_\omega(x), \\ \omega &= \omega_t \in \{1, ...52\}, \end{aligned} \tag{4.1}$$

where G_ω is a cumulative distribution function (CDF) on some finite set of outcomes X_ω (each element bounded). An alternative to this formulation would be to assume week-by-week realizations of demand schedules depending on price, incorporating demand elasticity in a more realistic manner. However, the analytical loss is small since for our purposes the interesting elasticity is given by the residual demand for hydro. This elasticity is to a large degree determined by the slope of the non-hydro supply curve. Yet another formulation would be to include persistence in seasonal shocks, as high demand in some week due to a cold spell may have implications for the next week's demand. Since we are uncertain about the relevance of this phenomenon in the Nordic area, we do not want to expand the state space by assuming correlated shocks in demand.

Production by other than hydro capacity has a week-specific aggregate cost curve

$$C : \omega \times z \longrightarrow R^1_+$$

which is increasing in z each week ω. We denote the weekly cost by $C_\omega(z)$. As explained, the seasonal variation comes from the availability of CHP capacity and from the maintenance pattern for nuclear and large coal plants. The definition of $C_\omega(z)$ incorporates the level of fuel prices and we could also include changing fuel prices explicitly. Indeed, we solve the planner's model under a stochastic fuel-price process when we evaluate the robustness of the results in Chapter 6. However, fuel prices are not structural variables of the Nordic market in the same sense as inflow and demand are because we cannot estimate fuel price distributions with the same accuracy. We find it important not to mix fuel prices with the market fundamentals because, as will be demonstrated, excluding the fuel price uncertainty has little effect on the predicting power of the model. Thus, we set up the benchmark model with a cost function depending on supply z and period ω only.

The final stochastic element of the model is the water inflow which we denote by r_t. The inflow at t is observed only after the hydro usage u_t is chosen but it is observed before the choice of the next period water use u_{t+1}. The inflow realization is, like demand, drawn separately for each week from a week-specific distribution:

$$\begin{aligned} r_t &\sim F_\omega(r), \\ \omega &= \omega_t \in \{1, ...52\}, \end{aligned} \tag{4.2}$$

where F_ω is a CDF on some finite set of outcomes R_ω (bounded elements).

Finally, the physical state, i.e. the hydro stock, develops according to

$$S_{t+1} = \min\{\overline{S}, S_t - u_t + r_t\} \tag{4.3}$$

where we include the reservoir capacity $\overline{S}$. Any inflow leading to a stock exceeding $\overline{S}$ is spilled over and left unused. The next period stock cannot go below a nonnegative lower bound $\underline{S}$; this constraint will be implemented through the choice set $u_t \in U(s_t)$. Now, if we fix a policy rule $u_t = g(s_t)$ and start from a given state s_0, the development of the state vector s_t is fully determined by the stochastic processes for x and r, and by the law of motion for S_{t+1}. To determine the optimal policy, we define next the per-period payoff for the decision maker at each t as

$$\pi(s_t, u_t) \equiv -C_\omega(x_t - u_t). \tag{4.4}$$

Maximizing π is equivalent to minimizing the cost of non-hydro production.[1] If we let β be the discount factor per period, the optimal policy $u_t = g(s_t)$ maximizes the discounted sum of the expected per period payoffs, or alternatively put, minimizes the social cost of meeting the current and future demand requirements generated by (4.1). Let $v(s_t)$ denote the maximum social value at state s_t. This value satisfies the Bellman equation

$$v(s_t) = \max_{u_t \in U(s_t)} \{\pi(s_t, u_t) + \beta E_{s_{t+1}|s_t} v(s_{t+1})\}. \tag{4.5}$$

Note that the existence of the optimal policy follows directly from the Blackwell's Theorem because the rewards are bounded and the state space is finite (see Stokey et al. 1989).

In the empirical application, all production is dispatched by market clearing in a spot market, where the residual demand $x_t - u_t$ is left for non-hydro producers. If the

[1] Minimizing the cost of thermal generation is a standard objective in hydro allocation literature, see e.g. Little (1954).

market is competitive,[2] it is cleared through bidding such that the spot price satisfies

$$p_t = C'_\omega(x_t - u_t).$$

We express the socially optimal hydro dispatch policy immediately in terms of the (socially optimal) market price p_t because the price will give (or approximate due to discrete action space) the shadow cost of not using a unit of water in the current period. Using the optimal policy $u_t = g(s_t)$, we see that the state s_t follows a stationary Markov process, and therefore it generates a stationary weekly price distribution. Let $p_t = p_g(s_t)$ denote the socially optimal price following when optimal policy g is applied at state s_t. As $t \to \infty$, we obtain a limiting week-by-week distribution for the state vector by the stationarity of the underlying Markov process, and thereby also a limiting week-by-week distribution for the prices:

$$\begin{aligned} p_t &\sim P_\omega(p), \qquad (4.6) \\ \omega &= \omega_t \in \{1, ...52\}, \end{aligned}$$

where $P_\omega(p)$ is the discrete CDF on some finite set of possible prices.

Denoting the first moments of the long-run weekly price distribution by μ_ω, from (4.6), we can describe the basic economic logic of the equilibrium using the long-run price distribution. The model allows various interpretations, depending how the market fundamentals are specified.

[2]In the empirical part, we estimate the non-hydro supply from data without invoking competitive behavior. Thus, $C'_\omega(z)$ is interpreted as the inverse supply curve rather than the true marginal cost curve. See Section 4.4 for detailed discussion.

4.2 Interpretations

Exhaustible-resource interpretation. Suppose the long-run price moments satisfy

$$\mu_1 = \beta\mu_2 = ... = \beta^{51}\mu_{52} > \beta^{52}\mu_1,$$

a situation that can arise, e.g., when the annual inflow is concentrated to the first week (or to some other week initiating the hydrological year). Then, the allocation problem is effectively an exhaustible-resource problem within the weeks of the year, equalizing the expected present-value prices across the weeks but not across the years: the new inflow at the beginning of the year makes the resource reproducible. Assuming that the decision maker indeed has enough flexibility to equalize expected prices within the year (to be discussed in detail below), the drop in the expected price must arise at the turn of the year as long as there is expected annual scarcity.

Storable-good interpretation. The long-run price moments can satisfy

$$\mu_{\omega_t} > \beta\mu_{\omega_{t+1}},$$

for all weeks that are relatively similar in terms of inflow and demand for hydro. In this situation, the equilibrium progresses as in standard competitive commodity storage models (Williams and Wright, 1991): inventories are held to the next period after relatively favorable inflow-demand conditions, implying storage demand up to the point where the current price equals the expected next period price, $p_t = \beta E p_{t+1}$; when the current inflow-demand conditions are relatively unfavorable, stockout may take place, and $p_t > \beta E p_{t+1}$. However, when periods are ex ante similar in terms of inflow and demand, the expected long-run storage cannot be positive and the price means satisfy $\mu_{\omega_t} > \beta\mu_{\omega_{t+1}}$. Consistent with this reasoning, the long-run price distribution is skewed as the storage demand eliminates extremely low prices that would arise when storage is not allowed (see also Deaton and Laroque, 1992).

When the market fundamentals are estimated from the Nordic market data, we observe that both of these interpretations are useful. The socially optimal long-run prices support the exhaustible-resource view of the expected year but the storage market view describes well the decisions at the annual level.

4.3 Characterization

The long-run price means are useful in conceptualizing the nature of the market, but the realized price sequences may follow a logic that can be difficult to relate to the long-run price distributions. For ease of interpretation of the empirical results, we explain next how the state-dependent optimal policy, the current price, and the market fundamentals are linked.

Consider the optimal policy $g(s_t)$, and let $d_t = d(s_t)$ be an alternative policy that deviates from $g(s_t)$ only at current t,

$$d(s_t) = \Delta + g(s_t),$$

where $\Delta \neq 0$ and coincides with $g(s)$ at all other dates and states. We can define

$$\bar{p}_t = \bar{p}(s_t, \Delta) = \frac{\pi(d(s_t)) - \pi(g(s_t))}{\Delta}$$

as the average cost change caused by the one-shot deviation Δ. Recall that the grid for actions determines the smallest feasible Δ; when Δ is small, then $\bar{p}(s_t, \Delta)$ is approximately equal to the market price, p_t. We can thus interpret $\bar{p}_t$ as the approximate price in the following:

Proposition 1 *Assume there is an alternative policy to $g(s_t)$ at s_t, i.e., $\Delta \neq 0$ and $d_t \in U(s_t)$. Price $\bar{p}_t$ and the alternative have the following relationship:*

$$\Delta > 0 \Longleftrightarrow \bar{p}_t \leq \beta^k E_t \bar{p}_{t+k} \text{ for some } k \geq 1. \tag{4.7}$$

$$\Delta < 0 \Longleftrightarrow \bar{p}_t \geq \beta^{k'} E_t \bar{p}_{t+k'} \text{ for some } k' \geq 1 \tag{4.8}$$

Proof. See Kauppi and Liski (2008). ■

In the empirical application, feasible choices are constrained, e.g., by storage and turbine capacity, water availability, and river flow restrictions. When these constraints allow a deviation upwards from the optimal policy at state s_t, i.e. $\Delta > 0$, then the cost saving today, given by $\bar{p}_t$, is weakly lower than the expected loss from future cost increase implied by increased usage today. That is, the current "price" is lower than some expected future discounted "price". Similar reasoning holds in the other direction.

When inflow and demand distributions for hydro vary widely across weeks, the set of conceivable prices can shift from one period to the next, and there is no general way of achieving the present-value price equalization. Even when the optimal policy is unconstrained in equilibrium, i.e., it is possible to use or save more water at state s_t, the current price can be lower than some expected future price

$$p_t < \beta^k E_t p_{t+k}$$

and higher than some other expected future price

$$p_t > \beta^{k'} E_t p_{t+k'}.$$

This pattern in no way contradicts Proposition 1. The optimal policy seeks to minimize the difference in expected present value prices but no price equalization is guaranteed. For this reason the long-run price moments can satisfy

$$\mu_\omega \leq \beta\mu_{\omega+1}$$

over some weeks when, for example, inflow is high in week ω so that the storage capacity is likely to be binding. Then, in expectations water is frequently dumped to the market in that period. Alternatively, expected demand may be high enough to frequently require maximum production in week ω but even more so in the next week $\omega+1$. Finally, minimum flow requirements at low demand periods can bias price moments downwards from what would otherwise hold for some particular weeks.

4.4 Calibration of the benchmark model

In this section, we describe the data and the estimations needed for the calibration of the planner's model. We use weekly observations from the six years 2000-2005; a period over which the institutional and market environment was relatively stable. Here, we calibrate the model as suggested by the data, but in Chapter 6 we re-evaluate the data inputs and the distributional assumptions using a structural estimation procedure.

For demand, we use weekly demand data for the Nordic market in 2000-05 as published by the Organization for Nordic Transmission System Operators (Nordel). As explained earlier, in a given week, the consumer demand is assumed to be inelastically drawn from the demand distribution. We assume that demand is normally distributed with the weekly means and standard deviations computed from the data.[3] The distribution is then mapped to a finite grid. The step length of the grid was fixed at 200 GWh, leading to an average of 5.4 demand states per week.[4] The weekly support of demand in the model follows the empirical support as observed in the data.

Inflow energy is assumed to be log-normally distributed, and the parameters of the distributions are estimated using data from the period 1980-1999.[5] National inflow data is published by Norwegian Water Resources and Energy Directorate (NVE), Swedenergy and the Finnish Environment Institute. As with demand, inflow is mapped to a finite grid, with an average of 27.5 possible inflow levels per week.

Hydroelectric generation is represented by a single reservoir and power plant, and we use the aggregate market reservoir capacity of 120 TWh and the aggregate weekly turbine capacity of 7.9 TWh as the key parameters of the hydro sector.[6] There is no publicly available information about minimum flow constraints but, after presenting the main results, we experiment with different levels of minimum production. For the minimum reservoir level, we use a lower bound of 10 TWh for the whole Nordic system. The choice of the minimum reservoir level is shown below to have important implications for the results,

[3]Demand for electricity showed little trend growth over the sample period. Testing for normality is difficult due to the fact that the data contains only six observations for each week. Nevertheless, a Shapiro-Wilk test supports the normality assumption, rejecting it (at the five percent level) only for weeks 12, 25 and 41. On average, W = 90.0 and P = 46.9.

[4]For example, demand varies between 8.2 and 9.6 TWh in the first week of January. All variables measured in energy must be discretized using the same step length to keep track of the evolution of the reservoir level. Thus, while a finer grid for demand might seem plausible, decreasing the step length would also increase the reservoir space. The current choice of step length is determined by the computational burden and memory requirements of the market power model.

[5]A Shapiro-Wilk test was applied to the inflow series (1980-99) of each week of the year. Averaging over the weeks, W = 95.5 and P = 52.5. The null hypothesis of log-normality was rejected at the five percent level for two weeks (weeks 25 and 29).

[6]The aggregation assumption is discussed in more detail in the section on robustness. Försund (2007) calls the equivalency of an aggregated plant and a system of independent plants under ideal conditions the Hveding conjecture, after Hveding (1968). Försund also provides a detailed discussion of the conditions under which the conjecture is a reasonable approximation of an actual hydro system.

and we will discuss this choice, too, in the chapter on robustness. The regulatory lower bound of the aggregate reservoir level is based on the importance of the hydro resource as a fast power reserve supporting the electrical system. However, it is unclear how this constraint is enforced in practice. Bye et al. (2006) refer to a statement by the NVE, according to which the actual minimum level of Norwegian reservoirs was 8 TWh (10%) in the spring of 2003. Nordel uses 5% (6 TWh) of total reservoir capacity as the lower bound for aggregate reservoir level in the simulations of its Energy Balances publication. Amundsen and Bergman (2006) refer to a total minimum reservoir level of 15 TWh in 2002, and to 12 TWh in 2003. Given that only water that is actually used to generate electricity (as opposed to water stored in a reservoir) can support the electrical system, it seems that the minimum reservoir level requirement is bound to be a soft constraint. For this reason, and taking into account the figures mentioned above by the other authors, we see 10 TWh to be a conservative estimate for the minimum level of reservoirs.

For the residual demand of hydroelectricity, we can follow two routes. We can use engineering data on the fleet of non-hydro power plants in the Nordic area to build an aggregate marginal cost curve.[7] Using this data we can in principle follow the approach from Wolfram (1999), also used in Borenstein et al. (2002), to construct the theoretical supply curve for nuclear and thermal plants. In this market the theoretical non-hydro supply curve experiences considerable seasonal shifts because of heating demand (electricity is cogenerated with heat) and planned maintenance outages. Moreover, for the hydro usage decisions we need to know the expected future supply of the non-hydro power; the value

[7] A data set containing all plants of relevant size in Finland, Sweden and Norway has been collected by the firm EME Analys for use with the PoMo market simulation model. We thank Per-Erik Springfeldt and Karl-Axel Edin for sharing this data with us.

of water in a given state can be computed only by evaluating its value in possible future states. At this point, the expert data set becomes dependent on subjective assessments of patterns in capacity availability and maintenance.

For the above reason, we rather estimate the seasonal supply of the non-hydro capacity than use the engineering data. We thus estimate the weekly supply function of the thermal sector from data on the weekly system price and total demand in 2000-05. A conceptual difference to Wolfram (1999) follows: by estimating the thermal (all non-hydro) supply from the data, we include all the strategic distortions that may exist in this part of the market (nevertheless, it is a conceptually valid approach to evaluate the efficiency of hydro use separately, given the behavior of the thermal sector).

The system price data is published by Nord Pool, while electricity production by technology is reported by Nordel. We used the European Brent spot price for the price of fuel oil as reported by Reuters. We regress the thermal supply on the logarithm of the price of electricity, the prices of fossil fuels and the time of year.[8] A majority of the marginal cost of thermal plants consists of the price of the fuel. As explained, the thermal generation costs vary within the year for reasons related to heating demand and maintenance, both of which follow a seasonal pattern (nuclear plants and other large thermal power plants follow a seasonal maintenance schedule). To capture these effects, we include month dummies d_t in the regression equation,

$$z_t = \beta_0 + \beta_1 \ln p_t^{elec} + \delta q_t + \gamma d_t + \varepsilon_t,$$

[8]The semi-log supply function fits the cost structure of an electricity industry well, and has been used before by e.g. Bushnell, Mansur and Saravia (2008) to estimate the supply from fringe firms that they do not model explicitly using plant-level cost data.

where z_t is the thermal supply, and q_t is the vector of fuel prices. The thermal generation is composed of all other production than hydro, including wind power and the net import of electricity. The price depends on thermal generation, and is thus endogenous. There are two natural candidates for instruments, the hydro production and the level of reservoirs, both of which influence the price level but not the cost of thermoelectricity.

We report our estimation results in Table 4.1.[9] The first panel of the table contains the results of the first stage of the two-stage least squares regression. The first column of the table represents the model with fossil fuel (coal and oil) prices as regressors and aggregate reservoir level as the instrument for price. Fossil fuel prices are strongly multicollinear, and the price of coal is dropped from the model depicted in the second column. Finally, the third column reports the results of the same model as in the second column, but using hydro output instead of reservoir levels as the instrument. As expected, there is a strong negative relationship between reservoir levels and price. The same holds true for total hydro output and price. The second panel of Table 4.1 presents the second stage results. The parameter values and the model fit are very similar for the two instruments. We take this as an indicator of the strength of the instruments since the correlation between output and reservoir levels is not perfect. Given its slightly better fit in the first stage, we use the model with reservoir levels as instruments in the calibration.

We note here that the purpose of the estimation is to find a stationary supply curve that shifts only because of the seasons within the year. This way we seek to obtain a fair description of how the hydro producers viewed their residual demand ex ante; it would

[9] Statistical significance is marked with (**) at the 1% level and (*) at the 5% level. The standard errors (in parentheses) have been corrected for heteroskedasticity and autocorrelation. The regressions also include the monthly dummy variables. The number of observations is lower for the first model than for the other models, because the data on coal prices starts from April 2000.

Panel A: First stage results

	(1)	(2)	(3)
Oil price	0.0199**	0.0197**	0.0205**
	(0.0017)	(0.0016)	(0.0018)
Coal price	-0.0019		
	(0.0014)		
Reservoir level	-0.0280**	-0.0290**	
	(0.0015)	(0.0015)	
Hydro output			-0.0006**
			(0.00004)
R-squared	0.71	0.70	0.59

Panel B: Second stage results

	(1)	(2)	(3)
ln(price)	1200.9**	1185.4**	1254.1**
	(43.3)	(43.2)	(47.9)
Oil price	-27.3**	-24.0**	-24.5**
	(1.8)	(1.7)	(1.8)
Coal price	7.1**		
	(1.4)		
Observations	300	313	313

Table 4.1: Results of the 2SLS thermal supply estimation

not be difficult to estimate the non-hydro supply more precisely using information that is available ex post. We want to include only supply shifters that we can include into the state vector defined earlier.

We set the fuel price equal to the observed average from the period 2000-05, but later solve the planner's model with a stochastic fuel price using the above estimated curve. However, we cannot solve the market power model with a stochastic process for the fuel price because of the curse of dimensionality. We find no evidence that the fuel price is important for our results regarding the market structure.

Given x_t, the estimated supply z_t gives the relationship between hydro output and market prices, and this is how the value of hydro is evaluated throughout the remaining

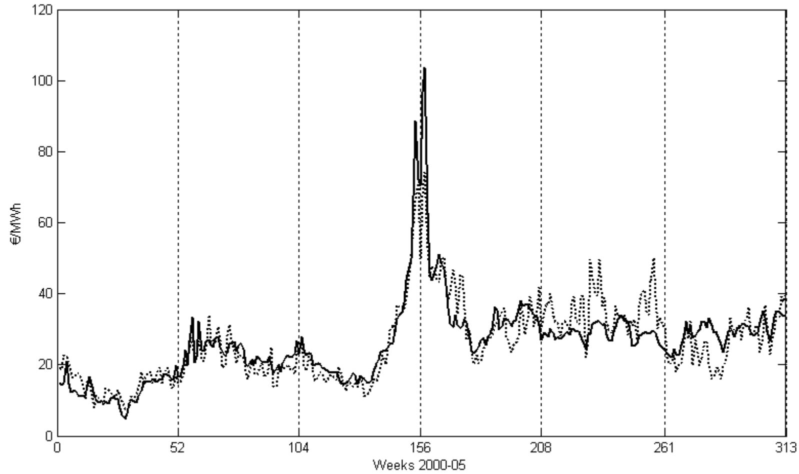

Figure 4.1: Observed (solid line) and estimated (dashed line) system price 2000-05. Estimation based on historical output levels.

of the thesis.[10] It is therefore important to illustrate how well this key input to the model describes reality: Figure 4.1 depicts the historical weekly prices and the prices obtained by using historical values for z_t and the estimated thermal supply. The fit is reasonably accurate for the whole period; in particular, the estimated price equation captures the price spike of 2002-03. However, the predicted prices deviate more from the actual prices after the price spike, which may be due to the fact that thermal plants rescheduled their maintenance patterns in response to the shortage of hydro after the price spike.

The annual discount rate is assumed to be 8 per cent, but we also experiment with other discount rates in Chapter 6.

[10] We do not impose an explicit capacity constraint on thermal output. This assumption is discussed in more detail in Chapter 6.5.

4.5 Computation

The calibrated benchmark model has in total 155 382 states. The optimal hydro policy is solved in all states under uncertainty over both demand and inflow. A computational problem of this magnitude requires the use of efficient numerical methods. We develop an algorithm for solving the model using a combination of backward induction and modified policy iteration. Modified policy iteration (See Puterman 1994) algorithms are a fast and easily implementable method for solving discrete time Markov Decision problems. A discussion about computational details and an overview of programming issues are given in the Appendix. The algorithm begins with an initial estimate of the value of water at the end of the year. Given this end value, we can solve for the optimal policies and water values for the entire year by backward induction. Then, using modified policy iteration, we iterate over the value of water in the first week of the year. For a given policy estimate, we compute its value over a fixed number of years. The value of the evaluated policy then replaces the current estimate of the value of water in the end of the year. We iterate until the week-by-week value function converges. The algorithm is described in more detail in the Appendix.

4.6 The benchmark results

4.6.1 Distributions of the key variables

We first generate the long-run weekly price moments by running the model over 2000 years, drawing random shocks from the inflow and demand distributions for each week.

Recall that we are not projecting the market to the future but, rather, studying how the model maps the distributions of the fundamentals, describing the market in 2000-05, to socially optimal price distributions. By letting the model evolve freely over 2000 years, the state of the market is likely to cover a wide enough range of scenarios for the construction of the price distributions.

The first moments of the weekly prices are in the upper panel of Figure 4.2, and the second moments together with the skewness of the prices are in the lower panel. The weekly long-run price means reveal the exhaustible-resource nature of the market: the spring inflow is in expectations depleted over the course of the year, leading to expected prices increasing quite closely at the rate the rate of interest until next inflow peak. The drop in the price expectation from week 18 to week 19 is .063, a number close to the discount rate.[11] In this sense, various constraints in the hydro system, as specified above, do not prevent a relatively close equalization of the present-value expected prices across the weeks. This is in stark contrast with the views of some market observers who argue that the seasonal behavior of the system price particularly in the early years of the market was due to insufficient hydro storage capacity. The average price level is 25.4 €/MWh, a figure close to the historical average of 26.3 €/MWh from the period 2000-05.

From the lower panel we see that the socially optimal price risk, indicated by the second moment of the weekly prices, increases towards the end of the hydrological year. This makes sense: summer and early fall are periods of relatively abundant storage and predictable demand. Considerable uncertainty regarding the overall annual inflow is

[11]The peak price is on week 17 and the lowest price on week 20. The reduction is .085 which is slightly higher than the discount rate. Regressing the expected price on a constant and weeks, starting from week 18 and ending at the next year's week 17, gives the slope .085 for the price curve.

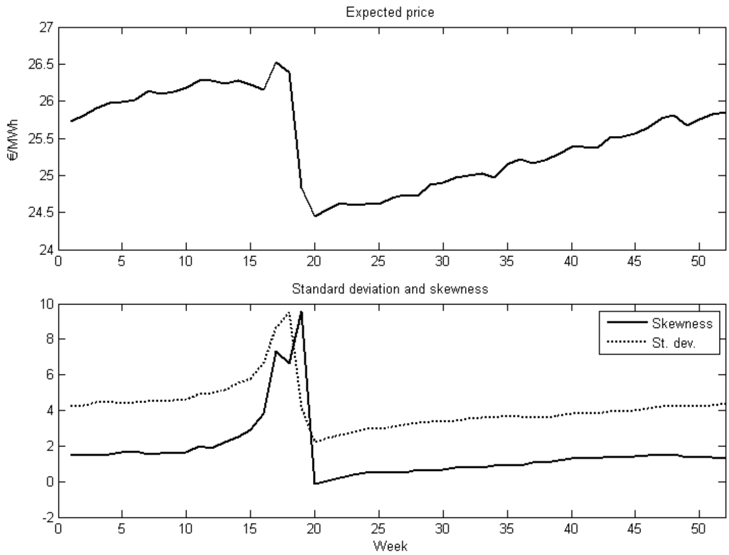

Figure 4.2: Simulated expected price (upper panel) and the skewness and standard deviation (lower panel) of price

revealed gradually during the fall, and unfavorable sequences of rainfall, or cold spells increasing demand, can lead to drawdown of stocks. Such risks are larger, the longer the period under consideration, which is why the socially optimal price risk must increase with time, until removed by a new inflow at the turn of the season. The skewness of price is positive and also increases towards the end of the hydrological year. This relates to the fact that the storage motives across the hydrological years dominate the market dynamics exactly there: the storage demand for the next year tends to eliminate the extremely low price realizations so that there are relatively few downward price spikes to match the upward spikes (see also Deaton and Laroque 1992 for discussion).

The expected shadow price from the long-run simulation is almost identical with the expected price. The shadow price has been calculated from the value functions by simply taking the difference of the value at the reservoir state one grid step above the current state and the current value, and then dividing the difference by the size of the grid step.[12] The slight difference between the simulated price and the shadow price is due to the estimation error arising from the discretization of the state space. In our benchmark calibration, we used a grid step of 200 GWh. In most market states that occur on the equilibrium path, an increase of this size in the thermal output corresponds to a price increase of 2-4 €/MWh. In absence of computational limitations, the grid step could be reduced enough to make this estimation error negligible.

Table 4.2 provides some descriptive statistics of the data produced by the long-run simulations. In extremely wet years, the market may run out of reservoir capacity in the summer and particularly in the fall. Over the 2000 year simulation run, the reservoir capacity is exhausted in total twelve times between weeks 33 and 42. In the actual market, such occurrences are much more frequent at the local level, where individual reservoirs may overflow due to unexpectedly high inflow. By assuming essentially that water is transferable between individual reservoirs, the aggregative model of efficient storage may yield too stringent a benchmark. If such real-life constraints force the hydro plants to allocate water in a way that mimics the behavior of strategic hydro firms, we must be careful not to interpret this as exercise of market power. This issue is discussed further under Chapter 6.

From Table 4.2, one can infer that the planner's hydro output choice over the long-run simulation is unrestricted by the flow constraints. Also, even though thermal output is not required to be less than the actual capacity in the market, the simulated thermal

[12]When the reservoir is full, and the reservoir state cannot be increased, the shadow price is computed from a one grid-step downward deviation in the reservoir state.

	Min	Mean	Max	St. dev.
Price (€/MWh)	7.58	25.41	167.25	4.31
Shadow price	6.99	25.34	153.90	3.99
Hydro output	1400	3868	6000	746
Thermal output	1400	3563	5600	568
Reservoir level	11400	63812	120000	25828

Table 4.2: Descriptive statistics on long-run simulations

production never exceeds this limit. We experiment with a thermal capacity constraint in Chapter 6.

4.6.2 Comparison with historical market outcomes

Let us now examine a particular sequence of events, i.e., the historical realizations of demand and inflow over the period 2000-05. Figure 4.3 shows two panels over the weeks of 2000-2005. The upper panel is for the aggregate storage and the lower one is for hydro output, both measured in gigawatthours (GWh). The socially optimal paths are calculated by setting the initial hydro stock equal to the observed stock at the beginning of 2000 and then letting it evolve as determined by the optimal policy. Demand and inflow realizations are taken as they in actuality occurred in each week but decisions are made under genuine uncertainty regarding the future.

The planner's output matches the observed output (the lower panel) quite well. Later, after introducing the alternative market structure, we will introduce criteria for matching the model with the data. Here, we note that the seasonal first moments (quarters of the year) for the observed historical output and social planner's output deviate on average by 5 per cent, which is less than one grid step in the planner's choice set for a significant

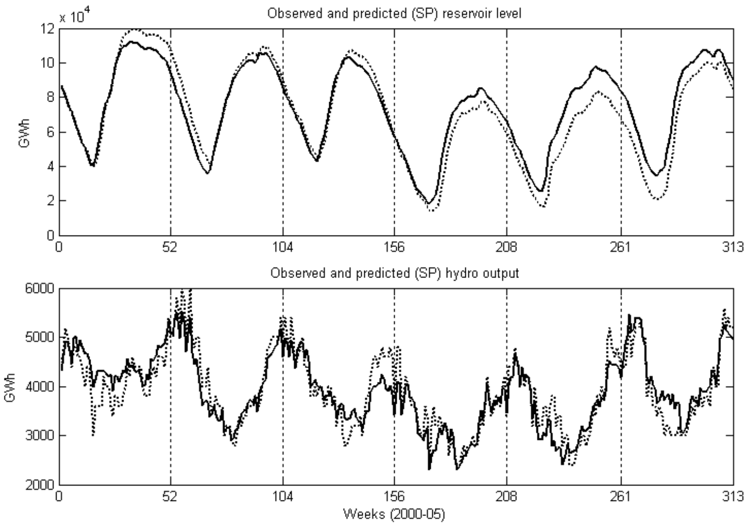

Figure 4.3: Upper panel: observed (solid line) and social planner's (dashed) reservoir levels. Lower panel: observed (solid line) and social planner's (dashed) hydro output

fraction of the time. The quarters are different with respect to the match such that there seems to be some tendency for the planner to save more water during the summer and spend more in the winter quarters.

While there is no clear systematic deviation in outputs, such a deviation is clear for the reservoir levels, as illustrated by the upper panel of Figure 4.3. The market and the planner have clearly differing target levels for the reservoirs. In the first two years, the planner seeks to save more of the abundant inflow (recall that we are forcing the observed and model stocks to be equal at the start), whereas later in the sample the planner would draw down the stocks more aggressively in response to the inflow shortage taking place in late 2002. Note that the planners differing stock levels arise not because of a systematic annual difference in usage but, rather, because of relative short and intensive 'steering' of

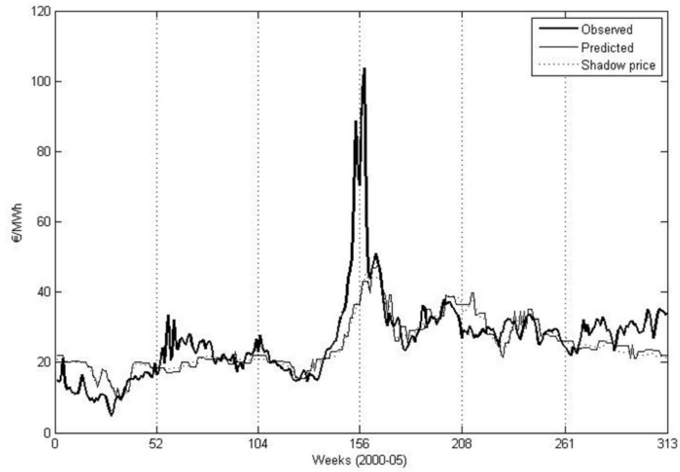

Figure 4.4: Observed price, predicted price and shadow price

the stocks in years 2000 and 2002-03.

The implications for prices are dramatic, see Figure 4.4. The planner can avoid the price spike of 2002-03 by more aggressive production. The mean price for the planner's model is 24.9 €/MWh, compared to the true historical average of 26.3 €/MWh. Prices are also clearly less volatile under social optimum, the standard deviation dropping from the observed 11.9 €/MWh to 7.5 €/MWh. In the last year of the sample, prices were partly driven by increases in the prices of fossil fuels. This is not taken into account in our benchmark model, but will be incorporated into the model later when we discuss the robustness of our market power analysis.

Figure 4.4 also plots the simulated shadow price from the social planner's model. The shadow price tracks the simulated market price almost perfectly. This is expected in a competitive market, where no constraints hinder the ability of the price-taking agents to arbitrage away differences in present value prices. The slight difference between simulated price and shadow price is due to the way the shadow price has been computed using the discrete reservoir state space as explained above.

The counterfactual simulation was started from the observed state of the market in the first week of 2000, and run over the whole six-year sample period by letting the state evolve according to the computed policy rule and the historical inflow and demand realizations. An alternative way to test the model would be to start one-week counterfactual simulations from each of the 313 weeks in the sample. In other words, instead of letting the system evolve freely, one could always readjust it to the historical state, and judge the model fit by studying the accuracy of the model in predicting the output choice in all of the observed states. Such a test would, however, force the state systematically away from the reservoir target level of the model being evaluated. When testing for the efficiency of long-run storage, it is more natural to let the reservoir state evolve freely, so that the policy rule is tested in the states that would have the highest frequency should the model be an appropriate representation of the world.

4.6.3 The role of uncertainty

How does uncertainty about inflow and demand affect the optimal storage policy? Could uncertainty give rise to storage behavior that might lead to similar outcomes as market power under some circumstances? To study this issue, we consider in this section a deterministic version of the benchmark planner's model. The model is altered only by replacing the stochastic processes 4.1 and 4.2 by the sample means of the respective distributions.[13] The resulting policy function is then used to simulate the deterministic outcomes using the sample means as the inflow and demand shocks. To compare the deterministic model to the stochastic model, we also simulate the benchmark planner's model along the sample means. After a sufficient number of simulation periods, the storage in both models adjusts to a steady state path. In the steady state, the planner holds higher stocks of water under uncertainty than in the deterministic setting. On average, the steady state stock is 9.6 per cent higher under the benchmark policy rule than under the deterministic rule.

Also the pattern of storage within the year changes. Under uncertainty, the planner conserves more water in the low-demand season. This precautionary saving is made under genuine uncertainty over the future, which could potentially entail a shortage of water during the winter. The convexity of the costs of the thermal plants makes the planner relatively more cautious of running out of water than of ending up with extra supply. Thus, at the end of the "average" water year, the planner is left with a small excess amount of water, which it releases gradually during winter, as the uncertainty about inflow is reduced by the approach of the spring melt-down of snow stocks. This change in the steady-state hydro release policy has minor effects on the simulated prices. In principle, uncertainty could require a policy that would lead to seasonality in prices within a year, when the inflow and demand realizations follow approximately their historical means. The results of the above exercise suggest that the effect of uncertainty does not resemble the behavior arising from market power.

[13] In addition, the grid step of the state space was halved to 100 GWh, since the simplification in the model reduces the computational complexity, allowing us to use a more accurate grid.

Chapter 5

Market power

5.1 The model

Using the framework introduced in Chapter 4, we now assume that a fraction of the reservoir capacity is strategically managed. We do not seek to map the observed market characteristics such as the market shares or the ownership of capacity to market outcomes but, rather, develop a stylized, while consistent, model of market power that remains empirically implementable in this relatively complicated dynamic market. The share for the strategic capacity, $\alpha \in [0,1]$, is our market structure parameter for which we can search values best fitting the data in Chapter 5.3. We assume that the fraction α is managed by one strategic agent (single firm, or an agent for a coherent group of coordinating firms). The rest of the reservoir capacity share, $1-\alpha$, is owned and controlled by a large number of competitive agents. Note that α is the share of the capacities (reservoir and turbine) and inflow, not the share of the existing hydro stock. The small agents are nonstrategic but forward looking, e.g., an individual competitive agent has no influence on the price but its decisions are rationally based on predictions for future prices, and these are formed using information that is available to all agents. This structure for oligopolistic competition remains computationally tractable, achieves the planner's solution and monopoly as limiting cases ($\alpha = 0$ and $\alpha = 1$, respectively), and, as we will show, will reveal quite a natural pattern for market power.

To separate the state vectors, inflows, and payoffs for the strategic and nonstrategic agents, we use superscripts m and c, respectively. Competitive agents are treated as a single competitive unit so that their state, for example, is

$$s_t^c = (S_t^c, x_t, \omega_t)$$

where S_t^c is the aggregate physical stock held by the competitive agents. There are thus two physical stocks that evolve according to

$$S_{t+1}^i = \min\{\overline{S}^i, S_t^i - u_t^i + r_t^i\},\ i = m, c, \tag{5.1}$$

where the reservoir capacity is what determines the size of the strategic agent: $\overline{S}^m = \alpha\overline{S}$. Both parts of the market have their own choice sets, $u_t^i \in U^i(s_t^i)$, and inflows r_t^i.[1]

The division of the aggregate inflow can have important implications for the exercise of market power. In principle, we would like to experiment with the correlation of inflows into the stocks S_t^c and S_t^m to study its impact on the equilibrium. Unfortunately, for computational reasons, we are able include only perfectly correlated inflows: the aggregate inflow is first drawn from the weekly distribution $G_\omega(r)$, as described earlier, and then this inflow is divided into the two stocks in accordance with α.

[1] For the planner's model, we did not impose any formal restrictions on spilling of water as the planner has no incentives to do so, but for the large agent this incentive is material. Therefore, we want to impose a spilling constraint (implemented as a financial penalty on water spilled over in the numerical part). We have been told that the hydro plants are monitored for spilling.

We look for a subgame-perfect equilibrium in the game between the strategic and nonstrategic agents. To save on notation, we let s_t now denote $s_t = (s_t^m, s_t^c)$. At each period, the sequence of events is

1. States $s_t = (s_t^m, s_t^c)$ are observed;
2. Strategic agent chooses u_t^m;
3. Nonstrategic agents make the aggregate choice u_t^c;
4. Non-hydro production clears the market: $z_t = x_t - u_t^m - u_t^c$;
5. Inflow available at $t+1$ is realized.

When we impose a Markov-restriction on strategies, this timing implies that a policy rule for the strategic agent depends on both states, $u_t^m = g_t^m(s_t)$. As said, we treat the nonstrategic agents as a single competitive unit and thus look for a single policy rule for this unit, $u_t^c = g_t^c(u_t^m, s_t)$.[2] It is useful to think that the competitive agents' policy seeks to solve the planner's problem of minimizing the overall social cost of meeting current and future demand requirements, given the current and future strategic behavior of the large agent. In this sense, the competitive agents minimize the cost of market power arising from the concentration of capacity in the hands of the large agent. Solving such a resource allocation problem for the competitive agents is the appropriate objective as it will generate a policy rule that implies a no-arbitrage condition for small storage holders. Thus, no small agent can achieve higher profits by rearranging its production plan from what we describe below.

[2]Notice that the Stackelberg timing simplifies the market clearing. Small agents' policy depends not only on the state but also on u_t^m, and so we do not have to dwell on complications caused by simultaneous moves.

Letting $v_t^m(s_t)$ denote the overall expected payoff for the strategic agent at state s_t, we see that a pair of equilibrium strategies $\{g_t^m(s_t), g_t^c(u_t^m, s_t)\}$ must solve

$$\begin{aligned} v_t^m(s_t) &= \max_{u_t^m \in U^m(s_t^m)} \{p_t u_t^m + \beta E_{s_{t+1}|s_t} v_{t+1}(s_{t+1})\}, \\ p_t &= C'_\omega(x_t - u_t^m - u_t^c) \\ u_t^c &= g_t^c(u_t^m, s_t). \end{aligned}$$

While an individual small agent takes the expected path of both stocks as given, aggregate u_t^c can be solved by minimizing the expected cost-aggregate from meeting the demand that is not served by the large agent. Let $v_t^c(u_t^m, s_t)$ denote the value of this cost-aggregate. We define

$$\pi^c(u_t^m, u_t^c, s_t) \equiv -C_\omega(x_t - u_t^m - u_t^c)$$

as the per period payoff and note that equilibrium policy $g_t^c(u_t^m, s_t^m, s_t^c)$ solves the following recursive equation

$$v_t^c(u_t^m, s_t) = \max_{u_t^c \in U^c(s_t^c)} \{\pi^c(u_t^m, u_t^c, s_t) + \beta E_{s_{t+1}|u_t^m, s_t} v_{t+1}^c(\tilde{u}_{t+1}^m, s_{t+1})\},$$

where $\tilde{u}_{t+1}^m$ is taken as given by equilibrium expectations. Having observed u_t^m, the expectation for the next period stock S_{t+1}^m is fixed by the knowledge of the inflow distribution. Similarly, for a given u_t^c, the next period competitive stock S_{t+1}^c can be estimated using the inflow distribution. Therefore, competitive agents can correctly anticipate the next period subgame (s_{t+1}^m, s_{t+1}^c) and the strategic action $u_{t+1}^m = g_t^m(s_{t+1})$. The equilibrium expectation $\tilde{u}_{t+1}^m$ must be such that the current period action u_t^c, through the physical state equation (5.1) for S_{t+1}^c, fulfills this expectation:

$$\tilde{u}_{t+1}^m = E_t g_t^m(s_{t+1}).$$

In this way, competitive actions today are consistent with the next period expected subgame, without any strategic influence on the market price.

If there exists a stationary long-run equilibrium, we can drop the time index from policies and value functions. We solve the equilibrium by a long backward induction and use the first year weekly policies in the empirical application.[3] In this procedure, the existence of the equilibrium is not an issue.

5.2 Interpretation

We have illustrated in Chapter 4 that the hydro market has features of an exhaustible-resource market (allocation of the spring inflow) and a storage market (savings to the next year). In an exhaustible-resource market, market power is exercised by a sales policy that is more conservative than the socially optimal policy: sales are delayed to increase the current price[4]. In the hydro market, the seller is not free to extend the sales path in this way because of the recurrent spring allocation which limits the length of the period over which there is scarcity of supply. In this sense, the ability to exercise market power as in exhaustible-resource models is limited. Nevertheless, the seller can shift sales to the future by storing the resource excessively to the next year, and in general such behavior is profitable because of discounting.

For illustration, suppose that all actions are made at the annual level (one period is one year), that there is no uncertainty, and that the decisions described in the previous

[3]One can in principle test if such a finite-horizon equilibrium approximates a long-run equilibrium well by simulating the long-run value functions using the finite-horizon policies, and then computing the payoffs from one-shot deviations. However, using such a test for choosing the number of needed backward-induction steps is computationally demanding.

[4]See Hotelling (1931) for the analysis of a monopoly; Lewis and Schmalensee (1981) consider an oligopoly.

section are made in the beginning of the year where all agents receive a deterministic annual allocation of water. It is then clear the strategic agent can reduce current supply only by saving to the next year; in equilibrium, saving takes place to the point where the current period marginal revenue equals the next period discounted marginal revenue, minus the cost from marginally reducing next year's potential for supply reduction. When the agent cannot spill water, a given stock in the hands of the strategic agent has only a negative shadow price for him, as increasing the stock reduces the size of the 'sink' that is available for supply reduction. This mechanism will emerge clearly in the empirical part below.

5.3 Empirical implementation

We calibrate the market power model using the estimates for weekly inflow, demand, and thermoelectric supply, as in the model of efficient hydro use. However, we leave the strategic agent's capacity share parameter α open, and consider in next which α provides the best match with the data. We would like to find the capacity share parameter structurally, i.e., by maximizing the empirical match of the model, using the criteria discussed below, with respect to α. In principle, we follow this approach but we are limited to consider only a subset of values for α due to computational reasons. As opposed to the one decision-maker problem, the game cannot be computed using policy iteration techniques. Instead, we solve the equilibrium by straight backward induction over the weeks of 10 years. In each state, we need to solve the following fixed-point problem as part of the procedure for finding the market policy $u_t^c = g_t^c(u_t^m, s_t)$: a given u^c induces the transition of the expected stock s_{t+1}^c, which when used together with s_{t+1}^m in $\tilde{u}_{t+1}^m = E_t g_t^m(s_{t+1})$ determines the expected behavior of the large agent; in equilibrium, the assumed u^c for the state transition must be the same as the cost minimizing optimal u^c for an agent who takes the aggregate state transition as given. Since such a fixed-point may not exist on a discrete grid, we use a lexicographic criterion at each state: (i) if there exists a unique most consistent u^c, when consistency is measured as the distance between the aggregate and private u^c, then this u^c is chosen; (ii) if criterion (i) fails, we use the Pareto criterion for choosing among the candidates. We need to apply the lexicographic procedure in approximately 5% of the states depending on the size of the strategic storage α. In total, it takes several days to solve the model on a standard desktop computer, which limits the set of parameters we can consider.

5.3.1 Simulated long-run distributions

For comparison with the social optimum, we generate the long-run weekly reservoir, price, and production moments by running the model over 2 000 years using various capacity shares α. Figure 5.1 depicts the long-run weekly stock levels for the social planner (SP), and for α equal to $.2, .3$, and $.4$. The expected stock levels increase monotonically with the share of the strategically managed stock. This is consistent with the interpretation given in Chapter 5.2: the steady-state stock increase is a way to achieve the disposal of supply not meant to reach the market. Under uncertainty, the logic of market power is slightly more intricate than in the deterministic case, as will be illustrated shortly, but the implications for the expected stock levels are clear.

The long-run weekly first moments of price are in Figure 5.2 for the same parameter values. Two features can be observed. First, as expected, the price level increases with the

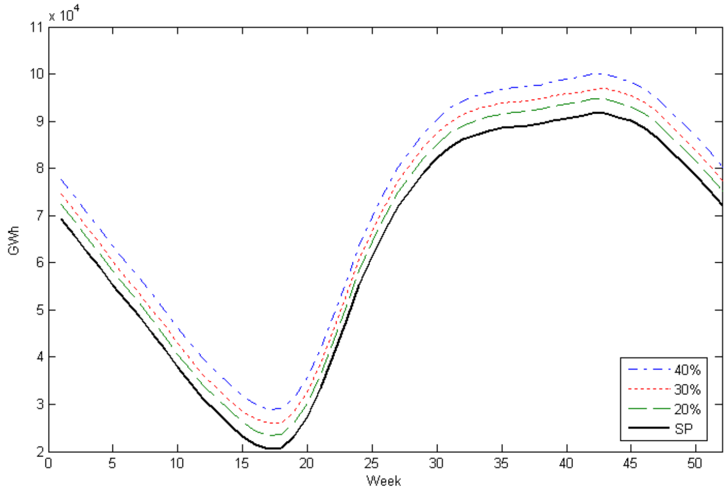

Figure 5.1: Simulated expected reservoir levels for different market structures

size of the strategic agent, leading also to a more marked fall in prices at the turn of the hydrological year in the spring. Second, for α sufficiently large, the highest expected prices are experienced earlier, before the end of the hydrological year. Our conjecture for the result is that a larger agent can follow a riskier strategy in the sense that water is withheld from the market earlier to take advantage of potential shortage of inflow during the late summer and fall: an inflow below expectations provides a welcome 'sink' for unused stock, so that less of the excessive saving must be carried over to the next year. On the other hand, if the inflow turns out be abundant, then the strategic agent needs to produce excessively, from his point of view, to prevent excessive storage to the next year. This latter effect tends to depress expected prices in the end of the year.

Besides increasing the expected price level, an increase in α makes prices more

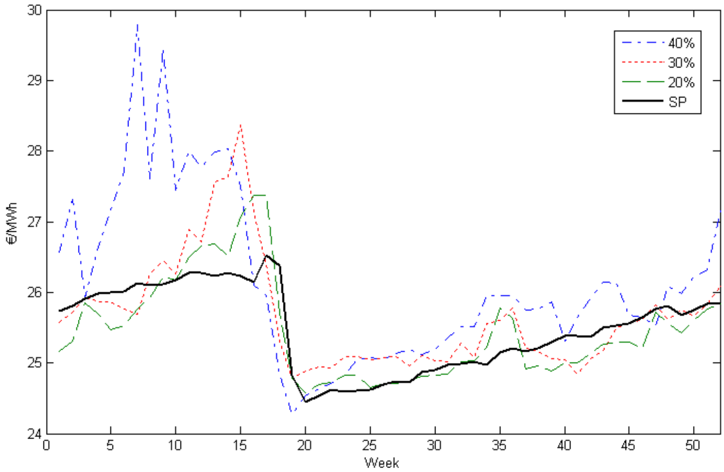

Figure 5.2: Simulated weekly price expectations for different market structures

volatile. Figure 5.3 depicts the weekly standard deviations for the four different models. Price risk increases throughout the year, but particularly in the winter season. Very high peak prices become more frequent, as the dominant firm's share is increased, but this effect, too, is mostly limited to the period between December and April. Price skewness increases in α in the winter, and stays relatively unchanged from the planner's model (see Figure 4.2) in the summer. However, for α large enough, prices become slightly left-skewed during the summer months.

5.3.2 Matching historical data

To consider the match with the historical data, we evaluate the equilibrium policies for a given α, using the historical realizations of demands and inflows over the period 2000-

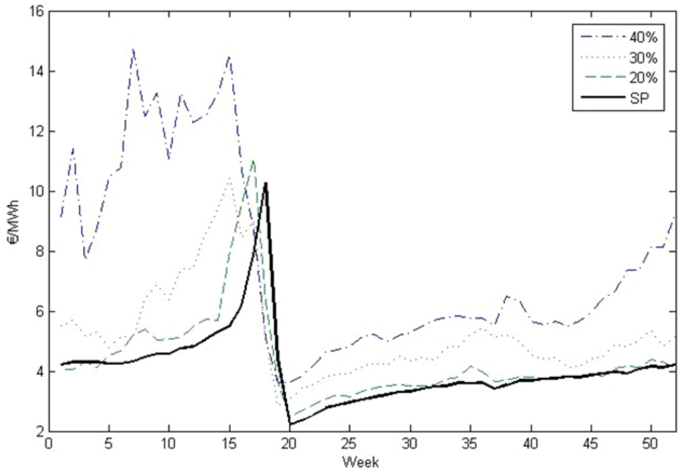

Figure 5.3: Simulated standard deviation of price for different market structures

05. We set the initial hydro stock equal to the observed stock at the beginning of 2000 and then let it evolve as determined by the equilibrium policies.

We look for α that best matches the historical data. In this procedure, we use the model predictions for three variables: the reservoir levels, output, and prices. It is clearly important to include reservoir levels in the set of variables, given that imperfect competition should become evident through this variable. Recall that there is a systematic discrepancy between observed reservoir development and that chosen by the social planner (Figure 4.3). Including both prices and hydro outputs in the set of variables would clearly be unnecessary if the "observed" prices were the ones computed from the estimated supply relationship using the historical outputs; in this case, there would be a one-to-one relationship between outputs and prices. However, since we use the real historical prices as our observations, it makes sense to use both prices and outputs in the matching procedure to evaluate the overall performance of the model.

Let $m_t(\alpha)$ be the model prediction for a (column) vector of the three variables at t, given α. If x_t is the historical observation for the same vector, the sample mean of the prediction error is[5]

$$g_T(\alpha) = \frac{1}{T}\sum\nolimits_{t=1}^{T}(m_t(\alpha) - x_t).$$

One criterion for choosing the model is to find a value for α that minimizes the quadratic form

$$H_T(\alpha) = g_T(\alpha)' W g_T(\alpha),$$

where W is a 3×3 weighting matrix (to be discussed below). A crude way to proceed is to choose $T = 312$, i.e., to aggregate over all weeks of the six-year period to form three simple moment restrictions. When $W = I$, the statistic has a straightforward interpretation: it is the sum of three least-square errors. This statistic is misleading since it completely ignores the Markovian nature of the policy rule: the statistic should be able to discriminate how well the model predicts variables as the state of the market changes. Another extreme is to let $T = 1$, which allows one to calculate the statistics $H_1(\alpha)$ for each of the 312 weeks, and then sum up these numbers (or average them). This approach would pay maximum attention to actions at individual states, but would not allow weighting the variances of the prediction errors when choosing W in $H_T(\alpha)$. The latter shortcoming can be avoided, for example, when $T = 13$ and the statistic $H_{13}(\alpha)$ is calculated separately for each of the 24 quarters in the data. Then, we can use the two-stage GMM approach[6] where in

[5] We are abusing notation on purpose here, hopefully without a risk of confusion, in order to follow the conventions of the literature using the GMM approach.

[6] See, for example, Cochrane (2001).

the first stage α is chosen for some given W, and in the second stage, we estimate the sample variance-covariance matrix of the prediction errors associated with the chosen α to construct a weighting matrix that depends on the data. In the second stage, we allow for serial correlation in the prediction errors associated with the chosen alpha by using the inverse of the estimated long-run variance matrix as the weighting matrix. The asymptotic variance matrix is computed using the quadratic spectral kernel proposed by Andrews (1991) and a bandwidth of three. The results are robust to different kernel types and to a large range of bandwidths.

We evaluate each model under different criteria ranging from moment restrictions for aggregated data to "path matching" using weekly data. For Table 5.1, we have first calculated the statistic $H_T(\alpha)$ for each model at different aggregation levels (weekly, monthly, quarterly, and semi-annual). In this calculation, we took W first as a given diagonal matrix and used the inverses of squared means of the relevant variables on the diagonal to transform the variables into comparable units.[7] The mean value of the statistic $H_T(\alpha)$, obtained this way, is reported in the first column for each model. The 35 per cent model provides the best score at all time aggregation levels.[8]

For quarterly and semi-annual predictions there is enough variation to consider the variance of the sample mean and to exploit the covariance-variance properties of the data in choosing the weighting matrix for the statistics. The numbers reported in the second column for each model are the mean values of the statistic over the 24 and 12 samples

[7] Otherwise, the stock variable dominates in the calculation. Correcting dimensions this way favors the hypothesis that there is no market power since the market power model is particularly good in matching the stock development.

[8] Due to computational reasons we have computed only seven market share values for the strategic agent: 0, 20, 25, 30, 35, 40, and 50 percent. Since we find no evidence for perfect competition, i.e., $\alpha = 0$, we do not believe that this coarse grid is essential for the main result.

T	SP		20%		25%		30%		35%		40%	
1	1.21	-	.82	-	.68	-	.55	-	.35	-	.66	-
4	1.20	-	.80	-	.66	-	.53	-	.34	-	.64	-
13	1.14	12.8	.75	10.5	.61	9.0	.48	7.7	.27	17.6	.57	25.6
26	1.06	73.6	.67	61.4	.53	48.7	.40	47.8	.21	85.7	.47	144.2

Table 5.1: Goodness-of-fit tests

	Observed	SP	20%	30%	40%	50%
Mean	26.3	24.9	25.2	26.4	28.0	31.0
Standard deviation	11.9	7.5	8.3	10.6	16.6	28.7
Skewness	2.5	0.9	0.9	1.4	2.3	5.4

Table 5.2: Descriptive statistics on the observed and predicted price series

(quarterly and semi-annual aggregation, respectively). The 30 per cent model minimizes the statistic $H_T(\alpha)$ obtained this way.[9] Note that $H_T(\alpha)$ from the 30 per cent model need not be the smallest, for example, in each of the 24 quarters, but only the mean value of the statistic has this property. We are thus putting equal weights to the match in each of the time periods.

Our main result is that a market share of 30 per cent for the strategic agent provides the best fit with the historical data under various criteria. In Table 5.2, we report statistics on the entire observed and predicted price series. The average price in the sample period was 26.3 euros. The socially optimal hydro policy would have yielded a mean price of € 24.9. The 30% model outperforms the planner's model in predicting the average, variance and skewness of price. It also outperforms the other market structures in the Table, with the exception of slightly underestimating the skewness of price compared to the 40% model.

Recall that for computational reasons we did not cover a very large set of α-values,

[9] The second stage test statistics for the 50% model (not reported in Table 5.1) are 42.9 and 314.3 for the quarterly and semi-annual aggregation levels, respectively.

which is why a better fitting market share parameter is likely to exist. However, we do not see a large gain from this search as α has no clearly defined empirical counterpart. The objective of the analysis is to merely show that there exists some market structure with market power that has more predicting power than the socially optimal structure. While it is clear that having one more parameter to choose, cannot hurt us ($\alpha = 0$ is always a choice), it is somewhat surprising that the model prediction is better in all dimensions (price, output, stocks). In Figure 5.4, we depict again the observed price, this time together with the predicted price under $\alpha = .3$ and the planner's solution. The market power model can replicate the price shock of 2002-03 quite well (the price shocks in 2003-04 originate from our supply curve estimation which does not capture well the change in the available thermal capacity; see Figure 4.1). In Figure 5.5, we see the systematic improvement in the reservoir match throughout the period 2000-2005.

5.4 A closer look at market power

In this section, we take a look at how the hydro use of the dominant firm differs from that of the competitive agents. These differences give us a clue as to how the hydro producer with market power can increase the price level. We focus on the results from the 30% model, which was found to be the specification that best fits the market behavior in 2000-05. Above, in Figure 5.1, it was shown that as the degree of market power increases, the expected aggregate level of reservoirs increases in every week of the year. Figure 5.6 illustrates how this additional storage is divided between the two hydro groups. The left panel shows the expected reservoir levels for both the dominant firm and the small hydro

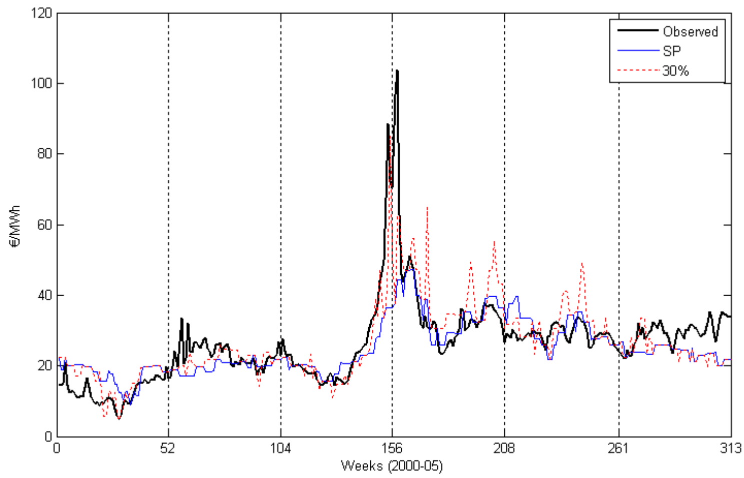

Figure 5.4: Historical, the socially optimal, and the market power (30%) price

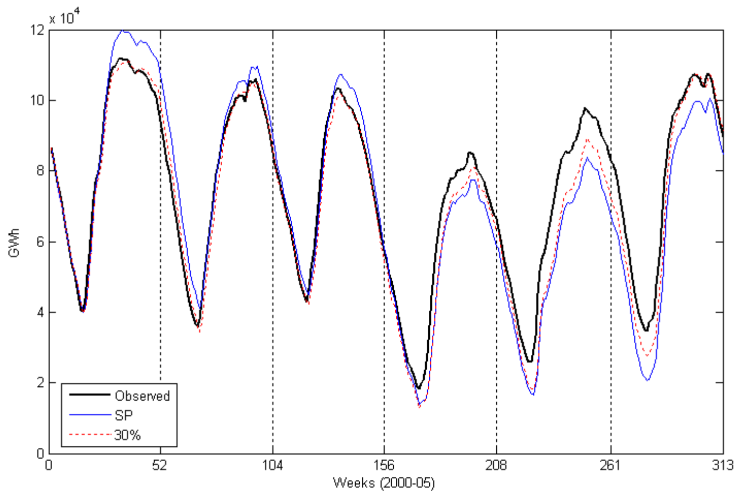

Figure 5.5: Historical, the socially optimal, and the market power (30%) storage levels

firms as a share of their total reservoir capacities. The right panel of the figure gives a breakdown of total demand by production source, showing how the storage behaviors of the dominant and the competitive firms are markedly different. On average, the dominant firm produces a fairly constant amount throughout the year, meaning that its output is disproportionately high during the summer.[10] In the winter, on the other hand, the roles are reversed, with the competitive agents generating a larger share of the total output. This pattern is consistent with the hypothesis discussed in public that dominant hydro firms use too much water during the low-demand season.

The flatness of the dominant firm's output schedule over the year forces the competitive agents to use their reservoir capacity more flexibly than under the social optimum. The competitive firms carry a large amount of water in the fall in preparation for the high-demand season. This is understandable: from the social point of view, there is a danger that unless the competitive firms have enough water in the reservoirs, the dominant firm will have too much influence on the price level during the winter. From the point of view of the small hydro producers it is profitable to store enough water for the cold season, since large profits can be made if the market does run out of water.

Because the dominant firm does withdraw output during the winter, its reservoir level is on average some 10 percentage points higher than under the social optimum in the last weeks of winter. The competitive sector is, however, large enough to smooth prices under most circumstances, as illustrated earlier in Figure 5.2. Nevertheless, the threat of the water running out forces the reservoirs to a higher level. As long as there is enough

[10] Over any given simulation run, however, the production of the dominant firm can vary considerably from week to week.

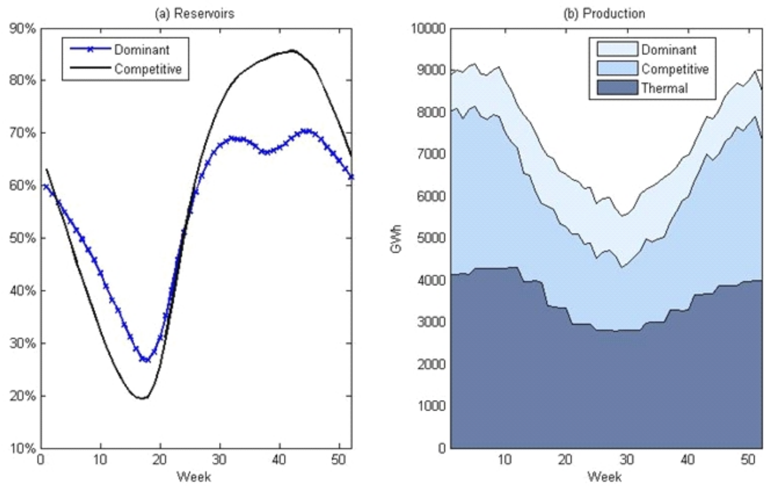

Figure 5.6: Left panel: The expected reservoir levels for the dominant and the competitive hydro firms. Right panel: break-down of total output by production source

leeway in the system, this behavior does not lead to great welfare losses. As α increases (the size of the competitive hydro sector decreases), the competitive reservoir capacity is put under more and more strain. In the simulated data, this is illustrated for example by the fact that as the value of additional storage capacity increases, forced spilling of water by the competitive firms becomes more frequent (although it is still very rare).

The exact way that market power is manifested in our model is dependent on the state of the market, and may vary from one situation to another. However, two main channels through which the dominant agent is able to influence the price level have been illustrated above. In the first place, for α large enough, water has a negative value for the large firm.[11] Since it cannot get completely rid of the excess water, it will rather produce

[11] The threshold is between 25 and 30 per cent. For the 30% model, the shadow price of water is on average -2.3 €/MWh. For comparison, the shadow price for the 40% firm is -13.1 €/MWh. The shadow price of the competitive agents follows the system price.

later than sooner, thus discounting the expected loss from the extra output. This behavior increases the expected level of reservoirs. The second channel was discussed above: the competitive agents tend to hold more water in storage to be able to smooth prices in the winter. The two explanations are not contradictory, since the dominant firm's slightly higher storage level does not restrain it from withdrawing output in the winter.

We have confined our discussion here to the range of the market power parameter α, which seems most likely to be of empirical relevance. However, as α is increased further, the workings of market power begin to change. The competitive agents are no longer able to smooth the discounted expected price over the year. Also, the expected level of reservoirs does not increase in α at the same rate any more. Early signs of this change begin to show at the 50% level, which is the largest α that we have considered here.

5.5 Predicting market outcomes

Our model can be used to analyze the market performance under different scenarios about the market conditions. For example, although it is not the main purpose of the framework built here, it is of interest to see how the model performs in predicting market outcomes in the short to medium run. This is also the function of several commercial market simulation models discussed briefly in section 3.3. Compared to these models, which are constantly recalibrated with current market data, our model is likely to be clearly less accurate on the short-run. However, within a time-frame that captures the seasonal allocation of hydro, our model can be expected to perform quite well. To illustrate this, we study how the model can be used to predict the mean and variation of the system price over a one-year horizon, starting from the first week of 2000. This discussion also highlights the difference between the long-run expectations discussed above (e.g. Figures 5.1-5.3), and expectations that are conditional on a given state of the market.

To construct the price distribution, we start from the observed state in the beginning of 2000 and conduct 10 000 one-year simulation runs drawing the inflow and demand shocks randomly from their respective distributions. Figure 5.7 depicts the distribution of prices for both the planner's model (left panel) and the 30 per cent market power model (right panel). The mean of the expected price is lower for the market power model almost throughout the period, averaging 19.6 €/MWh as compared to 21.6 €/MWh for the model of socially optimal allocation. This result highlights the importance of the no-spilling constraint: because all water must be used at some point in time, the price for the model of imperfect competition can be lower than the competitive price for sustained periods of time. The level of the reservoirs in the first week of the year was clearly above average, suggesting a low expected system price in the short to medium run. For the dominant agent of the market power model, this expectation also entailed an opportunity to release some of its excess water without depressing the price level too much (the value of water is negative for the dominant hydro firm), since its residual demand is more elastic at low levels of thermal output. The expected price for 2001 (not depicted in the figure) is uniformly higher for the market power model than for the planner's model.

The predicted prices also reveal that the price under social optimum is not expected to drop at the arrival of the spring inflow, in contrast to our results above in Figure 5.2. This is unsurprising, since the result holds true only for the long-run. In our example here,

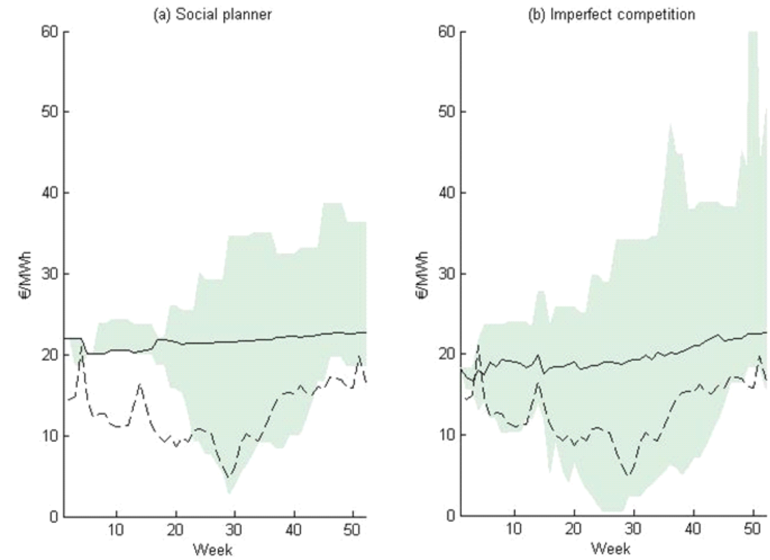

Figure 5.7: Distribution of expected price from the first week of 2000 (solid line: mean, dashed line: observed price)

each simulation run is started from a reservoir state markedly above the typical level in the first week of the year. Because of the abundance of water, price is expected to increase more rapidly than at the rate of interest. The reservoir capacity precludes (in expectations) allocating the extra storage of water over a longer time horizon, and thus the increase in output is concentrated in the first months of the simulation. For this reason, when we let the simulations run longer, the result reappears. For example, the price is expected to drop roughly by the interest rate in the spring of 2002 (and every spring thereafter).

In addition to the high storage in its first week, the year 2000 turned out to be a period of abundant inflow, with total inflow 18 per cent above the historical average. The water situation is reflected in the realized system price plotted in both panels of the figure for comparison. The shaded area in the figures is the support of prices from the simulations. The observed price lies below the support for the model of competitive pricing for the whole first half of the year, while being almost fully within the support for the market power model (and above the first percentile). In particular, the expected price for the planner's model is almost deterministic before the first spring inflow. The high initial storage also implies that even the highest price levels over the year are expected to be quite moderate. The variation in the market power model is much larger, and even price spikes of the same magnitude as in 2002 occur in a few of the simulation runs. These properties of the market power model seem to suggest that it may provide a better tool for forecasting future prices than the model of competitive pricing. However, as we have focused only on a single illustrative example characterized by somewhat exceptional inflow conditions, this conclusion should not be given too much weight in judging the relative performance of the models.

Chapter 6

Robustness analysis

In this chapter, we study the possibility that unobserved factors, mismeasured data and expectations, or limitations in the model structure can lie behind the pattern that we have connected to imperfect competition. We also test how well the planner's model and the best-fitting market power model perform in the two years following our sample period.

6.1 Unobserved reservoir capacity constraints

Reservoir constraints can have substantial implications for the main behavioral patterns in the market. In Figure 5.5, we see that the first-best reservoir levels overshoot the observed levels in years 2000-02 and then, in the latter part of the period, the deviation is to the opposite side. It seems clear that by sufficiently reducing the maximum reservoir capacity, we may obtain a better match in the years of overshooting, while a sufficient increase in the minimum capacity may improve the match for the remaining years.

We took the reservoir constraints from the data (see section 4.4) but now we look for constraints that maximize the model fit under the competitive behavioral assumption. We thus compute the social planner's model for all minimum reservoir levels (in TWh)

$$\underline{S} \in \{0, 1, 2, ..., 20\},$$

and all maximum reservoir constraints

$$\overline{S} \in \{112, 113, ..., 120\}.$$

These parameter sets were chosen based on historical reservoir levels, so the search was conducted over a range that should cover the "true" limits. After solving for the policy rules corresponding to the alternative parameterizations, we applied the policies at historically observed states, and then computed the two-stage GMM-statistic for each model. The model with the lowest test score provides the best fit with the historical data.

Using this procedure we find that the best-fitting pair is $\underline{S}$ =17 TWh and $\overline{S}$ =112 TWh. These choices lead to almost identical reservoir development with that predicted by our model of imperfect competition, and since the reservoir is important for the test statistic, the model fits are indistinguishable. However, the constraint adjustments cannot fully explain the observed price increase. These results are illustrated in Figure 6.1. Are the estimated capacity constraints consistent with data? The estimated lower limit of 17 TWh is implausibly high given the discussion in section 3.3. As such, the maximum capacity of 112 TWh is also off by being too low; higher actual levels have been observed since the deregulation of the Norwegian power market.[1]

[1] The aggregate maximum reservoir capacity in the Nordic market was almost constant throughout the sample period, being 120.5 TWh in the beginning of 2000 and 121.0 TWh in the end of 2005 (Nordel annual statistics 2001 and 2006). In 1990-2007, the maximum observed aggregate reservoir level in the market was 115 TWh (94.5%) (Nord Pool). In Norway, reservoirs have reached a high of 97.3% (1990-2007) and in Sweden 97.7% (1950-2007).

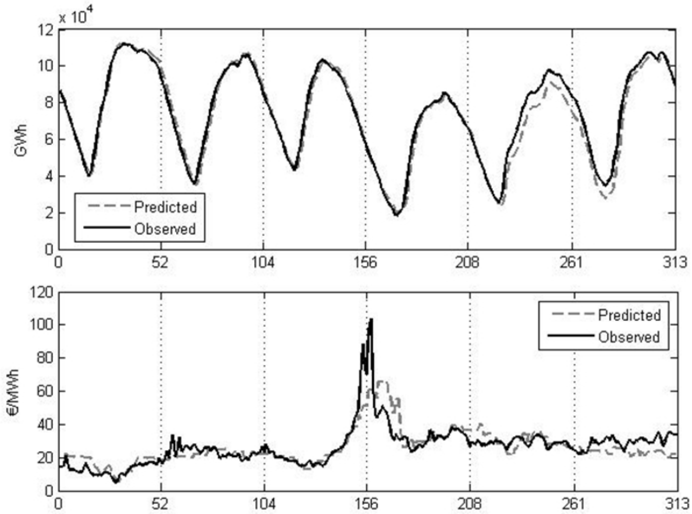

Figure 6.1: Model predictions with best-fitting reservoir constraints

It should also be noted that the capacity used in the model may proxy limitations in the hydro system arising from regional heterogeneity, and that therefore, there may not be a single number that would be the appropriate estimate of the maximum capacity for the whole sample period.[2] Such a constraint can artificially represent the unmodeled limitations that regional heterogeneity puts on the storage behavior.

For example, in the summer of 2007, the reservoir levels in Southern Norway were close to the capacity, and the local producers had to generate so much power to avoid overflow that they were unable to export all the power to other parts of the system, and the weekly average area price dropped to just 3.8 €/MWh in week 34, when the system price

[2] Ambec and Doucet (2003) point out that decentralized hydro output may lead to inefficiency losses that could be avoided under a monopolistic market structure. They argue that under certain constraints of the hydro system, the absence of a market for water may lead to an outcome, where the welfare loss from decentralization outweighs the gains from a reduction in market power.

was 16.2 €/MWh. In general, once the transmission line from a hydro abundant region becomes congested, increasing output in that region does not affect the prices faced in the other areas. Thus, the hydro producers in the other parts of the system have no incentive to reduce their output and save more water even though hydro output in the congested region is very high. Economically, transferring water from the congested area to the other regions would improve welfare. In our model, where all reservoirs are aggregated into a single storage, such uneven distribution of inflow has no similar consequences.

The estimated 112 TWh coincides with the actual maximum level in 2000, and thus forces the reservoir path to the true level. The reduction in the initial storage level also means that the planner is carrying less water in the end of 2002, and has less hydro resources to allocate to the price spike in the winter 2002-03. In the latter part of the sample, the maximum reservoir capacity has only a marginal effect on the optimal policy until in 2005, when reservoirs again approach the maximum capacity. On the other hand, the reservoir lower limit has a very small effect to the results in the first three years of the sample period, but during the winter of 2002-03, models with a higher lower limit for reservoirs do better than the less constrained models. The fact that more water must be left into the reservoirs seems to mimic the observed behavior, and it also keeps the reservoirs at a higher level throughout the latter part of the sample period. The reduction in hydro output 2002-03 due to the higher reservoir lower limit causes an increase in the price peak, although this effect is not of the same magnitude as for the market power model. It thus follows that one needs to adjust both the upper and lower limits for capacity to challenge the market power explanation. We find this implausible.

We also experimented with a minimum flow constraint. In principle, the popular hypothesis about hydro producers using too much water in the summer could also be explained by environmental flow constraints that require hydro plants to release a certain amount of water even during the summer, when the water might otherwise be stored in the reservoir. The river flow constraints are plant-specific, and there is no publicly available data about their magnitude. We considered several levels for the lower bound of hydro output, $\underline{u} \in \{0, .2, .4, ..., 2.8\}$ (in TWh). Low levels of the minimum flow constraint have no effect on the optimal hydro policy. For high enough levels, the model fit slightly improves. The fact that the planner must be able to meet the constraint on hydro output in future periods means that the planner must have enough water in storage to meet these future obligations. In the historical simulation, this effect can be seen as a gradual build-up of storage levels throughout the sample. This more conservative hydro use policy also implies slightly higher prices during the price crisis of 2002-03. Nevertheless, the influence of the minimum flow constraint is of secondary importance when compared to the reservoir level constraints.

6.2 Fuel price uncertainty

We took the oil price, which was the only statistically significant fuel price in the non-hydro supply, as an average price from 2000-05. Due to the curse of dimensionality, we could not solve the model of strategic hydro use with stochastic price, but we can solve the planner's model under this assumption.[3] We can therefore evaluate whether the fuel price

[3] The inclusion of oil price in the state increases computation time approximately linearly in the number oil price states. This is due to the fact that the most time-consuming part of the algorithm is taking the expected value over the reservoir state transitions. These transitions depend on the stochastic inflow process

changes can explain the discrepancy between the first-best and observed behavior. To this end, we assume a Markov process for the price. The price belongs to a finite set, roughly consistent with the empirical support from 2000-05. To be more specific,

$$
\begin{aligned}
p_t^{oil} &\in \{10, 12, 14, ..., 80\}. \\
p_t^{oil} - p_{t-1}^{oil} &\in \{-6, -4, -2, ..., 6\}
\end{aligned}
$$

The transitions are assumed to follow a normal distribution, the mean (.08) and standard deviation (1.46) of which are estimated from actual weekly oil price changes in 2000-05.

As illustrated in Figure 6.2, the fit of the planner's model's predicted price path improves with the inclusion of the oil price state, but the same is not true for the fit of the reservoir levels. The price effect is most pronounced in 2004-05, when the price of Brent roughly doubled from its level at the end of 2003. While the price prediction becomes generally more accurate, it does not replicate the observed price spike of 2002-03. Indeed, the predicted prices in 2002-03 are lower in the new model than in the benchmark planner's model. Uncertainty over future input prices increases the planner's incentive to store more water in the relatively water abundant years 2000-01. This increased storage is then used during 2002-03 not to alleviate price pressure due to high input prices, but due to the scarcity of water.

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and the current estimate of the planner's hydro use policy. Since the policy is dependent on the current oil price, the expectations must be computed for each possible current oil price state; hence the linear increase in computation time.

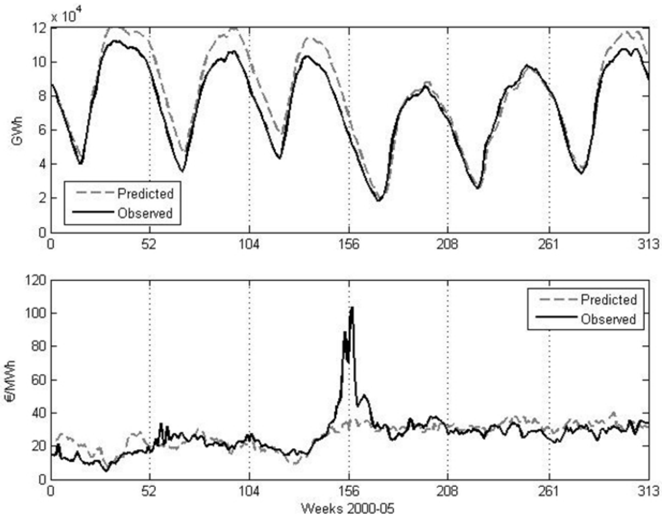

Figure 6.2: The reservoir and price paths for the model with oil price uncertainty

6.3 Discounting

We have used a discount factor that corresponds to an 8 per cent annual discount rate. Holding wealth in hydro stocks is relatively risky, justifying a rate above the risk-free rate, although we are unaware of prior studies elaborating what discount rates should be applied in this context.

To test which interest rate is supported by the historical data, we evaluated the alternative planner's models in the same way we compared the different α-values. Using the historical demand and inflow realizations, we simulated the price, reservoir and hydro output paths for all discount rates (percentages) in the range $\{2, 4, ..., 20\}$. We then computed the GMM test statistic for all models, using quarterly averages as observations. The test score is lowest for the model with 12 per cent discounting.

As one would expect, increasing the interest rate decreases the expected level of reservoirs. Earlier, we have shown that in the strategic model, raising the market share of the large agent increases the expected reservoir level. This effect is much stronger than the one from decreasing the interest rate in the planner's model. For example, even at a 2 per cent interest rate the planner's expected reservoir level is lower than in the strategic model with $\alpha = .3$ and the interest rate at 8 per cent. Since expected price increases at the rate of interest through the hydrological year, a higher discount rate implies higher output in the spring and summer periods and lower output in late fall and winter. A higher interest rate also increases the weekly standard deviation of price in virtually all weeks of the year, the exception being the weeks immediately following the start of the spring inflow, when variation is lowest and differences between discount rates are very small. Price skewness, on the other hand, is more variable when interest rates are low. In particular, prices are more positively skewed before the spring inflow and less skewed in the summer for low discount rates.

In the historical simulation, higher discounting lowers the reservoir level in every week of the sample period. Yet, even a very high discount rate does not explain the low storage levels in 2000. During the winter of 2002-03 the low reservoir levels due to higher discounting force the planner to use less water, thus causing a more pronounced price spike than in the benchmark model. Prices at the peak are, however, probably depressed by the high discount rate. That is, the planner is more willing to take losses in the future than now, and will therefore use water more aggressively. After the price crisis, higher discounting leads to slower build-up of the reservoirs.

6.4 Expectations

We also considered the possibility that our assumptions about the parameters of the demand and inflow distributions might be off the mark.

Given the low levels of storage in the early part of the sample, one possible source of bias could be too high expectations of future inflows. If expected inflow in the benchmark model is underestimated, then the high realizations in 2000 are seen as more valuable, and storage is higher. If, in reality, the expectations were higher than in the model, this could create a shortage of water in 2002-03, which could replicate the price spike. On the other hand, higher expected inflow should also lead to more aggressive use of water during a stock-out, as the producers believe that their storages will be soon replenished. This should then bring down the price spike in the simulation results. To test for these hypotheses, we increased the expected inflow mean by 5 per cent, leaving the variance of the inflow distribution unaltered. As expected, the change in expectations induces the planner to use more water in the early part of the sample than before, but the pattern is quite different from the actual hydro output. More specifically, compared with historical output, the new simulation results still overestimate the level of reservoirs in the water abundant year 2000, but a steadily decreasing reservoir level thereafter, so that storage is significantly lower than in reality in the summer of 2002 before the price crisis. The shortage of water then causes the prices to peak at a higher level than before, but the price spike is not as pronounced as in the market power models, for example. After the shortage, reservoir levels are built up too slowly compared to the actual pace. Overall, it seems that changing the inflow expectations in the described manner will bring about only a modest improvement in the model fit, at best.

The demand support used in the benchmark model was based on the empirical support of demand in 2000-05. To be specific, the week-specific lower bound of the demand space was set at the grid point below the observed minimum demand in that week, and the upper bound similarly at the grid point just above the observed maximum. We analyzed the sensitivity of the simulation results to the choice of demand support by considering mean-preserving spreads of demand uncertainty. We first decreased the week-specific lower bounds and increased the upper bounds by two standard deviations each. The probabilities formerly assigned to the lowest and highest demand levels were spread to cover the new support according to the original distributional assumption. That is, the mean and variance of the demand distributions were not changed.

Expanding the demand support has no effect on the historical simulation paths. We also experimented by altering the demand space in the high-season (weeks 45-10) only. This had no effect on the simulation results, either. Adjusting the demand space by four standard deviations has a small but almost indiscernible effect on the results. This change is virtually the same whether the demand supports are expanded for all weeks of the year, or for the high-season only.

6.5 Thermal capacity and price cap

In the current model, the thermal supply curve is assumed to represent all power sources other than hydro. Based on information in the Nordel annual statistics, the aggregate capacity from all non-hydro sources including imports was approximately 8 TWh per week in the sample period. The highest observed output from these sources during the same time was 5.5 TWh. The model has no explicit constraint on thermal capacity. This does not, however, mean that we assume an infinite supply of non-hydro power. Instead, one may interpret the supply exceeding the thermal capacity as stemming from elastic demand. After all, the hydro producers are interested only in their residual demand. An assumption about demand elasticity during an extreme power shortage is always going to be ad hoc, since we have not observed such a situation in practice.

Nevertheless, we experimented by constraining thermal capacity to be less than 5.8 TWh a week - a rather stringent condition given the theoretical maximum capacity. The capacity constraint must be paired with either elastic demand or with a penalty for lost load. The value of lost load (VOLL) has been estimated to be 2 000 €/MWh in the Nordic market. We use this figure as the price cap. Thus, up until thermal capacity, supply is determined by the estimated thermal supply curve as before, but at and beyond 5.8 TWh supply is flat. In the planner's case, this means that the planner incurs a cost of 2 000 € per each MWh of load that it cannot supply. The results are practically identical to the case, where supply is unconstrained. It should also be noted that in absence of the explicit capacity constraint the highest simulated (in a simulation run of 2 000 years) thermal output was 5.6 TWh a week for the planner's model, and 6.2 TWh for the best-fitting ($\alpha = .3$) market power model. Both figures are well below the total non-hydro capacity.

6.6 Out-of-sample predictions

In calibrating the models, we used actual market data to estimate the distributions of inflow and demand, and the supply of thermal power. While the data for inflow was from a period (1980-99) preceding the sample period 2000-05, both demand and thermal supply were obtained from the sample period data. This should not endow the firms in the model with too much foresight, since in reality, too, firms are well aware of the current capacities and fuel costs. Also, demand is usually forecasted with considerable accuracy for some time ahead. Nevertheless, it is of interest to test how the benchmark model and the 30% model perform in the two years following our sample.

The year 2006 was almost as dry a year as 2002 on aggregate terms. The pattern of inflow during these two years was quite different, however. In 2002, the hydro situation was initially very good, with abundant inflow in the spring and early summer. However, in August, inflow suddenly petered out, and remained very low throughout the rest of the year. Interestingly, the reduced inflow was almost immediately accompanied by a steady rise in the weekly average system price, which then peaked around the turn of the year. In 2006, inflow was particularly weak in the spring and summer. Indeed, the hydro situation looked very bleak in the summer, with the aggregate reservoir level a huge 29 TWh (28%) below the 2002 level in week 31. The average weekly market price kept increasing throughout the summer until a positive inflow shock in week 34. Inflow remained strong through the rest of the year, and prices in the winter 2006-07 dropped to their lowest level since 2000.

Counterfactual simulations for the out-of-sample period require some adjustments to the models due to changes in the market environment. One of the reasons for choosing the sample period in question was that the market conditions were relatively stable over those years. The last year of the sample was already somewhat exceptional due to the increases in prices of fossil fuels since 2004. For example, the average annual price of Brent crude oil in Europe was 27.6 €/MWh in 2000-03, 37.3 €/MWh in 2004-05, and 52.2 €/MWh in 2006-07. To take this rather large increase in the costs of thermal plants into account, we recomputed the models using the average oil price for 2006-07 in the thermal supply function (see section 4.4).

Apart from the adjustment in the price of the fossil fuels, we do not wish to make other alterations to the models in order to maintain comparability with the earlier results. If our goal was to match the model with the data as accurately as possible, some further readjustments would be necessary. First, the costs of the thermal sector were also affected by the commencement of the European Union greenhouse gas emissions trading scheme (EU ETS) in January 2005. By requiring a vast majority of Nordic thermal plants to cover their greenhouse gas emissions with tradable permits, the EU ETS has contributed to the increase in the marginal costs of thermal power generation. Second, demand has shown some trend growth in recent years, averaging about 140 GWh (or 2 per cent) higher on weekly level in the out-of-sample period than in 2000-05.

The out-of-sample simulations were started from the observed state in the first week of 2006, and run over the 104 weeks of 2006-07 using the observed inflow and demand realizations. Since we are mainly interested in whether market power still outperforms the competitive model, we computed the GMM test statistic only for the social planner's model and the $\alpha = 30$ model. It turns out that the market power model does provide a better fit also for the post-sample period according to the GMM criterion.[4] The 30% model fits the observed reservoir and output paths rather well, but does not improve the fit of the simulated price. This highlights the crucial role of the thermal supply estimate in our model. For 2000-05, the thermal supply estimate was quite accurate, because only small changes in the thermal sector took place during the period. For 2006-07, the estimate is simply too crude to capture all the changes that had taken place. Indeed, re-estimating the thermal supply curves using data from 2000-07 improves the model fit for both models considerably.[5] Although these readjustments render the out-of-sample testing rather useless, it is still interesting to notice that the market power fits the data better than the model of efficient hydro use.

Finally, it is, of course, entirely possible that the degree of market power evolves over time, and it is quite possible that the 30% model was no longer the best model in 2006-07. Several changes in the market environment may have changed the competitive position of the large hydro producers, including changes in the market structure, and changes in the market fundamentals, such as the increased costs of the thermal sector. Also, the expectations regarding the distribution of inflow may have been biased by the events of 2002-03, as the inflow shortage endured then was quite unprecedented.

[4] At $T = 8$, the second stage test statistics are .28 and .13 for the planner's model and the 30% model, respectively (see Chapter 5.3.2 for a description of the goodness-of-fit statistic).

[5] We also added a dummy variable for the out-of-sample years, and the square and cube of the oil price into the regression equation.

6.7 Discussion

We have shown above that the model of social optimum cannot be successfully calibrated to provide a better fit with the historical data than the market power model, if we change one element of the model at a time. A natural question is, of course, whether a certain combination of the factors considered above could be used to fine-tune the model without exceeding the limits that data puts on those parameters. An extensive search over a multidimensional parameter space is computationally impossible, since each new parameter set takes several minutes of computation time. However, the results reported above give us a general picture of the interplay of the different factors. Using this information, it would probably be possible to limit the search to a few of the key parameters. Nevertheless, the search would take a considerable amount of computation time, and is thus not undertaken in this thesis.

It should also be noted that such a recalibration of the planner's model would put it to an unfair advantage in our comparison, unless we would conduct a similar parameter search for the model of imperfect competition as well. Needless to say, the estimation of the best-fitting parameters for the market power model would be even more computationally demanding. Ideally, in absence of such computational constraints, one would include α among the parameters of the estimation procedure. In essence, our empirical question would then become, whether the market power parameter would still be significantly different from zero, even if all other parameters could be freely chosen (within their realistic supports).

Chapter 7

Welfare

The objective of the social planner in Chapter 4 was to minimize the total cost of meeting demand, and this is how we define welfare in this chapter, too.[1] We estimate the actual welfare loss incurred over 2000-05 by comparing the observed market behavior to the optimal policy derived from the benchmark planner's model. The realized cost is measured by interpreting the estimated thermal supply curves as aggregate marginal cost curves, and integrating over them to get the total cost of thermal output for each week in the sample. The accuracy of this estimate is obviously dependent on the quality of our thermal supply estimates, and should therefore be interpreted with some caution. Nevertheless, as illustrated in Figure 4.1 above, our thermal supply curve does predict the observed price levels quite well, and the error is likely to be smaller when aggregating over the sample period. The assumption that hydro power has zero variable cost is unlikely to affect our

[1] A more comprehensive welfare analysis would take into account the negative externality that the inefficient hydro scheduling puts on the environment by distorting the dispatch of thermal units. This would require using an aggregate supply curve based on actual plant-level data and information about the emissions of each plant type.

welfare estimates, since the variable costs of hydro power, consisting mainly of labor and maintenance costs, are not truly a function of the output, but can rather be seen as a fixed cost (Försund 2007). Since we are mainly interested in the cost difference between the actual and the socially optimal policy, the omission of the variable costs of hydro is likely to have a negligible effect on the results.

We estimate the total welfare loss from inefficient hydro allocation during 2000-05 to be approximately 621 million euros, or 7.2 per cent. The average annual cost of meeting demand under socially optimal hydro use is estimated to be 1.43 billion euros, while the realized cost is estimated at 1.54 billion euros. Most of the welfare loss is incurred over the winter of 2003, as expected. In water abundant years, the observed hydro use and the models with higher degrees of market power lead to lower total costs than the planner's model, since less water is being stored. Table 7.1 reports summary statistics on the costs of meeting demand for both the actual market outcomes and for the different market structures considered above. Besides being the best match with the historical data overall, the 30 per cent model also implies a welfare loss of 558 million euros, or 90 per cent of the estimated total welfare loss.

We also compute the expected welfare loss from different degrees of market power by simulating the system forward 2 000 years and averaging over the weeks. These results are reported on the annual level in the lower panel of Table 7.1. These results contain one of our main findings: in the long-run the estimated market structure where 30 per cent of hydro resources are owned by a dominant agent yields a mere 1.7 per cent increase in total costs. In other words, although the storage behavior under the 30 per cent model is distinctly

Panel A: Observed and counterfactual costs 2000-05 (bn. €)

	Obs.	**SP**	**20%**	**25%**	**30%**	**35%**	**40%**	**50%**
Total cost	9.22	8.60	8.73	8.85	9.16	9.49	9.74	10.80
Welfare loss	0.62	0	0.13	0.25	0.56	0.89	1.14	2.20
Welf. loss (%)	7.2%	0	1.6%	2.9%	6.5%	10.4%	13.2%	25.6%

Panel B: Expected costs (bn. €)

	SP	**20%**	**25%**	**30%**	**35%**	**40%**	**50%**
Annual cost	1.465	1.477	1.483	1.490	1.504	1.520	1.567
St. dev.	0.171	0.172	0.187	0.196	0.208	0.231	0.268
Welf. loss (%)	0	0.8%	1.2%	1.7%	2.6%	3.7%	6.9%

Table 7.1: Descriptive statistics on welfare

different from the efficient storage, it leads to quite modest welfare losses in the long-run. The presence of a significant amount of competitive hydro capacity hinders the dominant firm's ability to influence the price level under normal market conditions. The fact that the estimated welfare loss from market power over the sample period was so large is not in contradiction with this result. In a way, the negative hydrological shock experienced in 2002 was the ideal opportunity for the dominant agent of our model to exercise its market power. In our $\alpha = .3$ model, the sudden and persistent drop in the inflow levels in August 2002 prevented the competitive agents from accumulating enough water to smooth the prices in the winter. It seems likely that a reduction in inflow during the fall is particularly harmful in the presence of a dominant hydro firm. The competitive hydro firms cannot accumulate too much water in the spring and the fall, because a wet fall might then force their reservoirs to overflow. On the other hand, leaving too much storage space can be costly, too, if the fall inflow falls short of the expectations. Too low reservoir levels in the fall combined with a cold winter could then lead to the same scenario as in 2002.

While market power in the hands of some hydro producers leads to a loss in welfare, the gains from the price manipulation are divided between all electricity producers In the $\alpha = .3$ model, market power increases total profits in 2000-05 by 7.1 per cent. The increased profits do not offset the welfare loss from market power, because they are a direct transfer from the consumers to the firms due to the assumption about inelastic demand. The estimated increase in hydro producers' operating profits from the observed behavior are 264 million euros per year, while the thermal producers profit by 322 million euros. In the market power model, the dominant agent is able to capture a slightly larger share of the profits than it would receive as a part of an entity managed by the planner. For example, in the 30 per cent model, the dominant firm makes approximately 31.8 per cent of the hydro profits. The total gain to the dominant firm in 2000-05 is about 339 million euros. In the long-run simulations, the total industry operating profits are relatively constant at around 8.5 billion euros per year, but a slight redistribution from the competitive hydro agents to the strategic hydro firm and thermal producers takes place as the degree of market power is increased. For example, at $\alpha = .3$, the dominant firm reaps 31.4 per cent of total hydro profits, and at $\alpha = .5$ it captures 52.9 per cent. The thermal producers' share of total profits is 39.3 per cent under social optimum and increases to 41.4 per cent when half of the hydro resources are controlled by the strategic firm.

Finally, it should be emphasized that the estimated welfare losses and profits were computed using the thermal supply curves estimated from actual market data. In presenting our model, we did not specifically assume the thermal sector to be perfectly competitive. If thermal firms exercised market power, interpreting the estimated supply curves as marginal cost curves would overestimate the true costs of the thermal sector. This would in turn yield too low estimates of the aggregate welfare losses and profits. Our competitive benchmark is based on the assumption that the hydro capacity, but not necessarily the thermal units, are used in a socially optimal way. Thus, the welfare effects reported above are to be seen as deriving from inefficient hydro use alone.

Chapter 8

Conclusions

We have developed a framework that can be used to detect market power in storage markets. This method allows us to interpret market data to make a distinction between behavioral patterns arising from imperfect competition and those arising from fundamental factors in the institutional and economic environment. We applied the framework to the Nordic wholesale electricity market, finding support for the conclusion that imperfect competition can explain the main behavioral patterns in the market outcomes in years 2000-05. The data period includes an extraordinary hydrological event, which allows us to identify the pattern for market power. We estimated the market structure that best replicates the observed paths of key market outcomes. Market power was estimated to have lead to a significant welfare loss through inefficient dispatch of different generation types. Yet, in expected terms the welfare loss from the estimated degree of strategic behavior was found to be very small.

Thus far, the scant empirical literature on the Nordic market has been rather supportive of the performance of the market, finding little or no support for the market power hypothesis. This has been in contrast with the majority of research on other power markets, which has found strong evidence of market power both at the market level, and at the level of individual firms. In addition, the public opinion as voiced by the media has been much more critical of the market, often blaming the large producers for increases in the price level. To some extent, our findings reconcile these two polar positions. According to our results, the strategic firms do actively seek to maximize their profits by distorting the stocks from the socially optimal levels. However, a sufficient fraction of the hydro resources is operated competitively, and under most circumstances the competitive hydro supply is enough to offset the price influence of the strategic firms.

Our results show that exercising market power through long-run storage in this market is possible. What is perhaps comforting from a policy point of view is that a single firm cannot systematically move the system price by intertemporal reallocation of water unless it owns at least roughly a third of the resource, if the rest of the market behaves competitively. This does not, of course, preclude the possibility of oligopolistic competition or explicit or tacit collusion between hydro producers. However, based on the estimated degree of market power in 2000-05, the current level of concentration does not give cause to great concern about long-run hydro allocation as a source of inefficiency.

This conclusion does not mean that hydro power producers are never able to profit from their dominant position. Our analysis has focused on the long-run outcomes, which is a natural starting point as analyzing short-run outcomes is difficult without an understanding of the long-run. However, the very characteristics of hydro that motivated our analysis of the long-run behavior also give it a special role in the short-run. This is particularly true when the price area of a dominant hydro firm is separated from the rest of the market by transmission congestion. In general, a hydro producer may be able to take advantage of the variation in the elasticity of its residual demand by withdrawing output from the hours when it faces competition only from the local generators. Even then, a reduction in hydro supply will mean an increase in production at some future hour. The dominant hydro firm is likely to reallocate more water to the hours when it is competing against a larger market.

Short-run market power in hydro-dominated markets with temporary transmission congestion has received even less attention in the literature than the long-run case.[1] When hydroelectricity commands an additional state-dependent short-run return, the long-run allocations are also changed. Future research could look into the impact of short-run market power on the overall storage behavior of hydro producers. Empirically, such analysis could be based on either regional or firm-specific data.

Although there is valuable data available on the market level, access to more detailed data has thus far been extremely limited. In fact, the data used in this thesis represents more or less the full extent of publicly available information. In several other deregulated markets, researchers have had access to plant-specific data on production capacities, and even on actual plant-level outputs or firm-specific bidding. If such information does become available, one could potentially estimate hydro usage policies directly from the data, and use the policies to simulate the actual market valuation of water. The water values could then be used to estimate structural parameters of the market using the most

[1]The empirical test devised by Johnsen et al. (2004) was discussed above in section 3.3. In addition, Skaar and Sorgard (2006) study market power in a hydro-based market with temporary bottlenecks using a theoretical two-period model. They focus specifically on the strategic firms' incentives to create congestion (a feature absent in Johnsen et al.), and discuss its implications on merger policy.

current tools of the empirical industrial organization literature.

We conclude by discussing some of the possible shortcomings of our modeling approach. We already discussed in Chapter 6 how to use our benchmark model to test whether some unobserved factors or mismeasured data could explain the patterns that we attributed to market power. We found no such evidence, but this testing strategy has its limitations. One of the factors that cannot be easily represented using this approach is regional heterogeneity. The decentralization of hydro output decisions may lead to welfare losses even under perfect competition, if the constraints that the hydro plants face are different across regions (Ambec and Doucet, 2003). In principle, such constraints could produce market outcomes that resemble those arising from market power.

A more detailed regional modeling of the market would entail an expansion of the state space of the problem, which would further increase the computation time of our model. The computational limitations preclude the inclusion of some other possibly relevant state variables as well. For example, persistence in demand shocks might be a realistic addition to the model, since especially prolonged cold spells might have implications for storage behavior. Another variable that could facilitate a better representation of the true state of the market is the storage of snow. The size of the snow reservoir has obviously a bearing on the expectations about the inflow in the spring weeks. The inclusion of the snow stocks could improve the model fit at the end of the hydrological year. On the other hand, its exclusion is unlikely to significantly affect the long-run reservoir target levels.

Finally, a possible source of bias in our analysis of competitive behavior was the assumption of a risk-neutral decision maker. Behavior under risk neutrality and various constraints in the environment can bear resemblance to behavior arising from pure risk aversion. There are reasons to believe in risk aversion in the hydro resource use. For example, large players may want to avoid extreme outcomes (e.g., stockouts) to avoid creating political pressure on the market institution. These issues are left for future research.

Appendix A

Social planner's algorithm

In the following algorithm description, n will keep track of the number of iterations and t of the subperiod (week) within a year. T equals 52 in our application. In the evaluation phase, the temporary value function estimate is denoted by V to distinguish it from the true value function estimate v. In addition, τ keeps track of the subperiod and r of the iteration in the evaluation phase.

Step 1 (initialization). Set $n = 0$. Choose initial guess for the value function at time $t = 1$, i.e. $v_1^0 = v^0$. Set the tolerance limit for convergence, $\varepsilon > 0$, and select the order of the modified policy iteration algorithm, K. Set $R = K * T$.

Step 2 (policy improvement).

2.1 Set $v_{T+1}^{n+1} = v_1^n$ and $t = T$.

2.2 Solve for the optimal policy u_t^{n+1} and the value function v_t^{n+1} (equation 4.5). Set $t = t - 1$.

2.3 If $t = 0$, stop and go to 3.1. Otherwise return to 2.2.

Step 3 (evaluation phase).

3.1 Set $\tau = T$, $r = R$ and $V_{r+1} = v_1^{n+1}$ (computed in step 2).

3.2. Compute

$$V_r = \pi(s_r, u_\tau^{n+1}) + \beta E_{s_{r+1}|s_r, u_\tau^{n+1}} V_{r+1}(s_{r+1})$$

3.3 If $r = 1$ go to 3.4. Otherwise set $r = r - 1$ and $\tau = \tau - 1 + 1(\tau = 1) * T$ and return to 3.2.

3.4 Set $v_r^{n+1} = V_r$ for $r = 1, ..., T$.

3.5 If $\left\| v_1^{n+1} - v_1^n \right\| < \varepsilon$, go to step 4. Otherwise increase n by 1 and go to step 2.

Step 4. Set $u = u^{n+1}$ and $v = v^{n+1}$ and stop.

Appendix B

Computational issues

All program files used to produce the results reported in this thesis are available from the author by request. The main programs implement the dynamic programming algorithms described above. A short overview of the structure of these programs follows. Both programs begin with sections, in which the user may choose the key parameters of the models, such as the discount rate, the grid step length and the constraints of the hydro system. Given these choices, the program then defines the state and action spaces. The estimation results from the thermal supply estimation and the parameters of the weekly demand and inflow distribution have been computed independently and are stored as standard data files. This data is retrieved by the main program, which uses it to construct the vectors of possible demand and inflow realizations, and attributes probabilities for each realization based on the estimated distribution parameters. The computation of the planner's model is greatly facilitated by computing the transition probability matrix for the reservoir state before the actual function iteration. In the case of the market power model this is not necessary, since the structure of the algorithm precludes the use of transition matrices.

The thermal supply estimation results are used in constructing payoff matrices for the planner, and also for the dominant agent and the group of small agents in the market power model. These payoff matrices represent both the period-specific payoff from the product market equilibrium and the stage-dependent constraints on output choices. In particular, a large numerical penalty is imposed for using more water than is in stock. Also, in the market power model, the dominant agent is penalized for spilling water. Specifically, the firm incurs the penalty if the probability of overflow after the output choice exceeds a certain threshold. This means that under exceptional inflow conditions there may be spilling for which the agent is not punished, but the probability of such an occurrence is set to be very small.

The modified policy iteration algorithm of the planner's model (see Chapter 4) is implemented as a function iteration loop within which are nested the policy improvement phase and the policy evaluation phase. Policy improvement is implemented as a backward induction loop over the 52 weeks of the year, starting from the current estimate of the value of water at the start of the year. The new policy estimate is then evaluated by computing the total cost of following the policy over a fixed-length backward simulation. By far the most time consuming part of the algorithm is the computation of the expectations over different inflow realizations in the policy evaluation step. In practice, this involves the multiplication of two large matrices in each week of the backward simulation phase. The number of weeks in this backward simulation (also called the order of the modified policy iteration algorithm) can be chosen by the programmer. There is a basic trade-off: a longer simulation yields a more accurate estimate of the value of the policy, which speeds up convergence, but takes naturally more time. We chose to evaluate the policies over a 15 year backward simulation. The computation time does not seem to be particularly sensitive to this choice, however. The outer function iteration loop is continued until the value function estimate converges.

The computation time of the benchmark social planner model was 26 minutes. The computational burden is heavily influenced by the choice of the grid step of the discretized state and action spaces. The benchmark grid step was 200 GWh, chosen to enable direct comparison with the more computationally intensive model of imperfect competition. It is actually possible to solve the planner's model using a much more detailed grid. For example, a grid step of 100 GWh increases the computation time to 223 minutes. The changes in simulation results due to the denser grid are small, however, and are thus not reported here.

The algorithm for the model of imperfect competition (see Chapter 5) consists of a long backward recursion which nests another backward induction loop that captures the period-specific timing of the model. In particular, each period within the outer loop begins with the solution of the small hydro firms' problem. Second, the large strategic agent solves its profit maximization problem, given the policy function of the small hydro agents. Despite its apparent simplicity, this algorithm is computationally more intensive than the planner's model. This is due to the fixed-point problem embedded in solving for the small agents' problem. Since this fixed-point problem has to be solved at each possible state of the system, the algorithm has to loop through all states instead of handling multiple states simultaneously operating on large matrices. In case a fixed-point is not found, the program resorts to the lexicographic criteria discussed in Chapter 5.3. The computation time of the model of strategic behavior is increasing in the value of the α-parameter (over the relevant range). On average, the solution time was about five days.

The results of both models consist of policy and value function matrices. These matrices are used to simulate the results reported in this thesis. The simulations are based on either random or historical demand and inflow shocks. Random draws are made from the distributions estimated from the historical data. Historical realizations are retrieved directly from the sample period data. The computational burden of the simulations is small compared to the actual solution of the models.

The numerical models were implemented in MATLAB. A couple of more time-consuming subroutines were written in C and compiled as MATLAB MEX-files. These files can be called from MATLAB like any other MATLAB functions.

Depending on the accuracy of the discretization of the model (the grid step length), the programs (as written here) may require more virtual memory than is available on standard 32-bit systems. However, the benchmark social planner's model can be solved on a standard 32-bit system. To compute the model of imperfect competition, it is necessary to adopt a 64-bit system.

The results reported in the paper were computed on a Dell Precision 390 desktop (Intel Core2 Quad Q6600, 2.40 GHz with 6 Gb of RAM). A multi-core CPU speeds up the computation of the planner's model where much of the computational burden consists of operations on large matrices. The market power model could not be similarly speeded up due to the additional fixed-point problem in solving the hydro fringe's policy function.

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