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Alternative Drawdown Procedures for Hydropower Reservoirs

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Foreword

This Diploma thesis “Alternative Drawdown Procedures for Hydropower Reservoirs” is the conclusion of the author’s Master of Technology degree. The diploma thesis has been preceded by a project thesis bearing the same name but with an exclusive focus on the effect of the intervention price on power scheduling and prices. This focus of the effect of the intervention price has provided the author with a sound base for analysis and further learning. Consequently, this thesis is somewhat biased by the author’s previous work on interventions. However, the reader will quickly see that the prevalent focus in this thesis is the nature of elasticities in the Norwegian power market. Special attention is directed to the challenges associated with changing elasticities in hydro scheduling. This focus provided the author with ample study material and a good opportunity for a further understanding of the fundamentals of the Norwegian Power market.

The author would like to express his gratitude to his advisor, Dr. Ivar Wangensteen, for providing the assistance and motivation necessary for the completion of the paper. Also, Mr. Bjørn Grinden has been of great assistance when it comes to dealing with the intricacies of the EMPS-model. Dr. Stein-Erik Fleten is also recognised for his assistance with this paper. Finally, the author is very grateful to Erling Mork of NordPool for the use of the statistics database. Any shortcomings in this thesis are the sole responsibility of the author and must be attributed to an exceptionally pleasant spring in Trondheim.

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Abstract

This paper seeks to demonstrate the effect of several measures designed to alter the drawdown procedures of hydropower reservoirs. Particular focus is directed towards how price spikes and extreme prices in dry year scenarios respond to changing elasticities..

The paper begins by outlining the characteristics and regulation of the Norwegian power system. Focus is directed to these key characteristics: The system is almost exclusively dominated by hydropower. Also, power is freely traded on the Nordic power exchange, Nordpool. Finally, there exists some international trading, but transmission capacity is limited. As the fundamentals of the Norwegian system are established, focus is turned toward the management of hydropower resources in an open market, with a focus on generation scheduling. Further, the concept of options is explored with a clear focus on how these may have an impact on elasticities. As the paper narrows its focus to the specific question at hand, a short description is given of the computer program used in order to carry out the simulations and calculations necessary for this paper. Sintef Energy Research's EMPS (EFI's Multi-area Power-market Simulator). The EMPS is a comprehensive water-value based simulator which is used by several power producers and should consequently be a suitable simulator for this task.

Before any simulations are shown, some of the economic theory governing this aspect of the power market is laid out:. Further, the mechanics of elasticities are explored together with their interaction with options. On this basis, several hypotheses on how price spikes may be curbed are founded.

Simulations of the power market based on the formulated hypotheses using inflow data for every year from 1930 to 2000 are carried out, but special attention is given to the dry years of 1939, 1940, 1941 and 1969. The simulations comprise the entire European market as defined in the EMPS model, but only the results for Norway are used for further analysis.

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1 Introduction

This thesis seeks to illustrate the nature and effects of demand elasticity in the Nordic power market. Special focus is directed towards the implications of elasticity in hydro scheduling. As the possibility for extreme market conditions as experienced in the winter of 2002-2003 is present, generation schedulers must take into account how such situations impact the demand for power in the market. Traditionally, demand has been considered predictable and has proven to be relatively price insensitive. This thesis will investigate this supposition in light of the evidence available from the recent extreme market situation. In order to achieve this objective, the recent development of market environment and conditions is studied. Then, the theory of demand elasticity is considered along with available literature documenting the nature of elasticities in the Nordic power market.

However, the chief focus of this thesis is the challenges met by the generation scheduler in the market. Consequently, extensive use of the EMPS model is made. The EMPS model remains the reference simulation tool for scheduling hydropower drawdown. Consequently, the use of elasticities in the EMPS will dictate how elasticities are analysed in scheduling. In this light, extensive work with the EMPS is carried out to see how price and production is forecasted for various scenarios with different approaches to the elastic nature of demand.

The results provided by the EMPS model viewed in conjunction with the previous inspection of market conditions and the theoretical approach to elasticities should provide a sufficient basis for a clear understanding and discussion of the current handling of demand elasticities in generation scheduling.

From this discussion, any results or recommendations for further work will be presented.

2 The Power Balance in the Nordic Market

2.1 Introduction

The current situation in the Nordic power market is largely governed by the following major influences:

- The free power market/NordPool
- A strong dependence on hydropower
- A higher level of consumption than production
- A strong public opinion against development of hydropower capacity

This chapter will maintain a strong focus on the power situation in Norway. However, the large capacity for cross-border electricity trading in the Nordic market is not only a prerequisite for the well-functioning power market in the region (NordPool); it also sometimes dictates a broadening of the scope of inquiry to the entire Nordic area. Particular for Norway is the practically exclusive dependence on hydropower, whereas the other Nordic countries depend on subsidiary power sources such as nuclear power and natural gas.

2.1.1 Brief History

Hydropower has in some form or other been used throughout much of the last millennium of Norwegian history. Initially, mills and sawmills were powered by mechanical energy harnessed in the moving water of rivers and streams. Towards the end of the 19^{th} century, hydro-electricity plants were being constructed. Consumption has grown steadily since the introduction of electrical grids in Norway as shown in Figure 2.1.

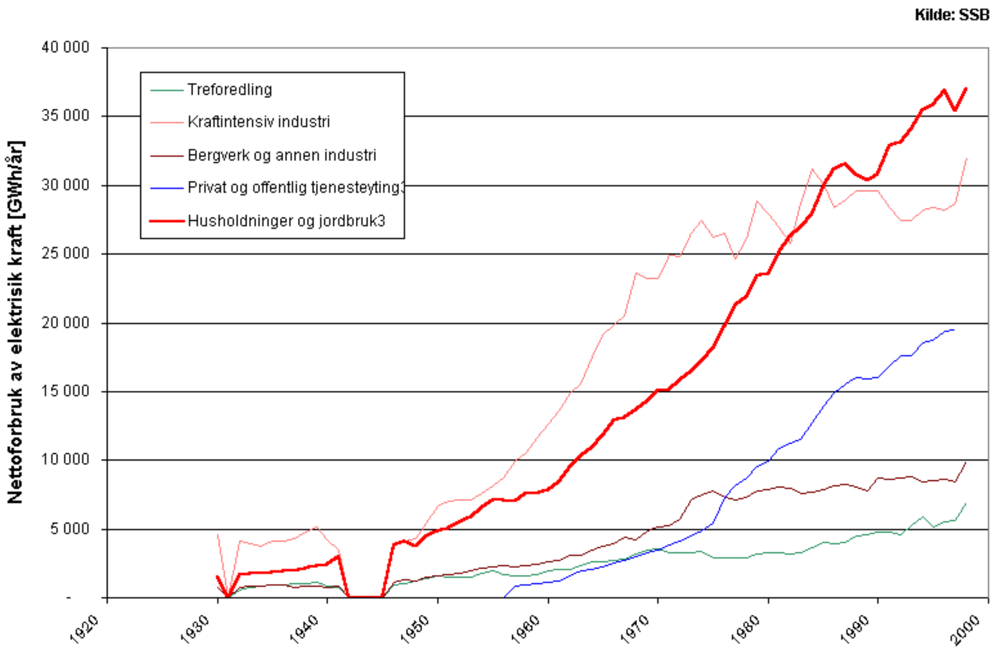

Figure 2.1 Net Consumption of Electrical Power in Norway by Sector 1930-2000. [Statistics, Norway]

2.2 Current Status

The total power consumption in Norway in 2002 was 120.9 TWh. This consumption has increased steadily since the introduction of the deregulated market. In 1993, after the deregulated market had settled, total consumption was 102 TWh. Interestingly, consumption in 2002 was less than in 2001 when the total consumption was 125,5 TWh, largely due to higher prices.

Net import was -9,673 TWh (i.e. export) in 2002 and 3,592 TWh in 2001. The high level of export in 2002 was a result of excess storable inflow in the spring of 2002. However, the summer and autumn of 2002 turned out to be very dry, and this high level of export turned out to be a liability when low reservoir levels contributed to historically high power prices in Nordpool's spot market in the winter of 02/03.

This dramatic shortfall resulted in a situation where the Norwegian reservoirs were nearly depleted at the end of the drawdown season in the spring of 2003. Even in the late summer of 2003, Norwegian reservoirs were not close to being replenished. In week 27 of 2003, the aggregated Norwegian inflow was 8% less than in 2001 and 22,7% less than in 2002[Flatabø, 2003]. Obviously, with some reservoirs capable of storing the inflow of several years, the effects of the extreme depletion of the 02/03 winter may very well carry over to the following year and can thus impact the reservoirs and consequently the prices also in the future.

However, as shown in Figure 2.2 below, reservoirs are showing a tendency of repletion in 2004.

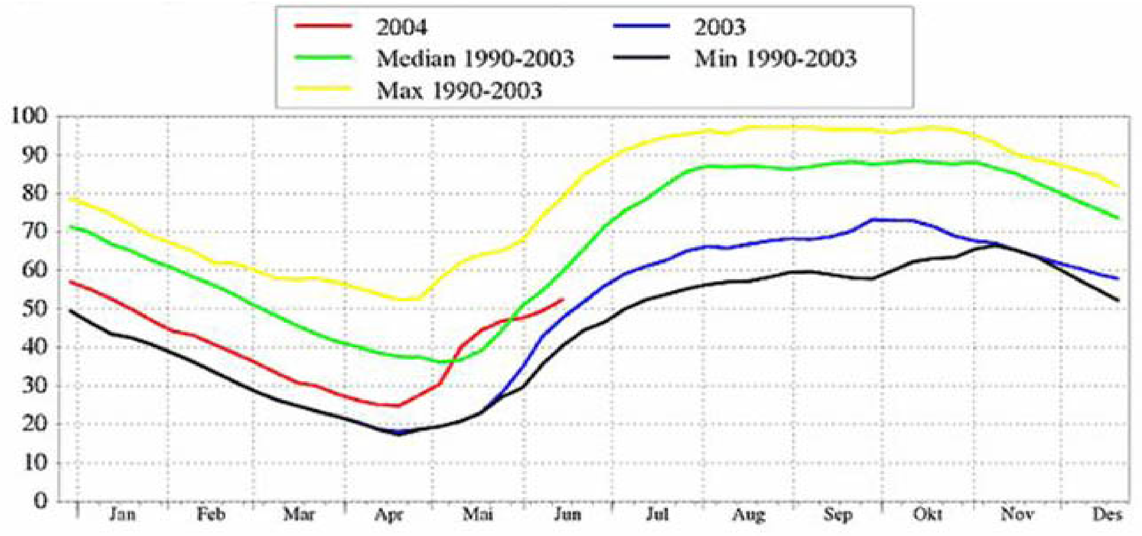

Figure 2.2 Aggregated national reservoir levels (percentages) [Statistics, Norway]

2.2.1 Energy Shortfall

Norway has progressively relied more and more on importing energy primarily from Sweden and Denmark. Transmission capacity between Norway and Sweden is quite high at while transmission capacity in and out of the Scandinavian Peninsula remains low, as shown in Figure 2.3.

The consequences of an energy shortfall are generally feared in Norway. An example of this is the White Paper, Stortingsmelding nr 18 (2004) which studies the probability and negative consequences of a potential energy shortfall. Special attention is paid to the price explosion which will accompany an energy shortfall and which was experienced in the winter of 2002-2003 when the spot price for electricity at NordPool, the Elspot, achieved a record high of more than 800 NOK/MWh which is also shown in Figure 2.5.

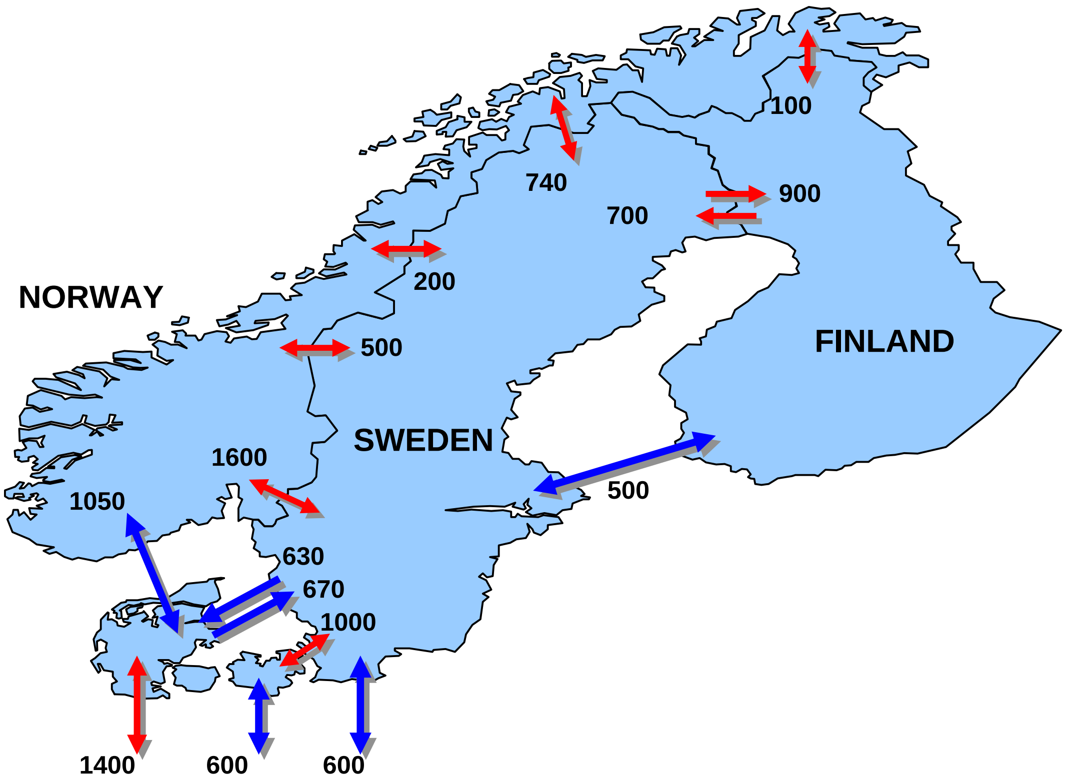

Figure 2.3 Transmission capacities in the Nordic Power market [Wangensteen, 2003]

Since Norway and Sweden to a large degree have common "Hydrological features", (i.e. a dry year in Norway usually means a dry year in Sweden too). This lack in transmission capacity has proven to be a liability. In the winter season of 2002-2003, practically all transmission capacity into Scandinavia was running at full capacity in order to compensate for the low reservoir levels and consequent high power prices in this region.

Another interesting consequence of the energy shortfall has been a fall in the liquidity of the term and OTC (Over the counter market)[1] market. By early May 2003, only 658 TWh was traded and cleared at NordPool Clearing vs. 1142 TWh at the same time in the previous year. The extreme prices and volatility in 2003 contribute to the risk of trading large future contracts volume was 1142 TWh. Also compounding this effect was the exit from the term market of several risk seeking foreign capitalists and some Norwegian market makers. [Montel, 2003]

[1] For a more detailed description of power trading, see chapter 2.3: The Nordic Power Market

2.3 The Nordic Power Market

The Norwegian power market has been internally progressively deregulated since 1971. The natural conclusion of this process came in 1991 with the introduction of an energy bill allowing a pricing regime for all users which reflect supply and demand and consequently adhere to the laws of the free market. Initially, trading was handled by the system operator (TSO) Statnett. In 1996 Sweden also deregulated its market, resulting in the establishment of the Nordic Power Exchange NordPool ASA. Incidentally, this was the first example of a multinational energy exchange in the world, despite the tendencies of electrical grids to transcend national borders. In 1998 Finland joined the common exchange. The Danish mainland (Jutland) and the island of Funen joined in 1999, while the main Danish island (Zealand) joined the market in the autumn of 2000, thereby making Nordpool a true pan-Nordic market.

The Nordic Power Exchange is divided into two entirely separate exchanges. One exchange, “Elspot” deals with the physical spot market. The other “Eltermin” is a financial market which allows for hedging or speculation. Finally, “Over-the-counter” (OTC) markets are also provided by NordPool where both physical and financial contracts are traded. As of January 2002, the Elspot market is operated by NordPool Spot AS, which again is owned by the TSOs in the Nordic countries

2.3.1 The Elspot market

In 2002 124,4 TWh was traded on the Elspot market. The total turnover in the spot market in 2002 was NOK 26,4 billion [NordPool, 2004]. Hourly Elspot, power contracts are traded daily for physical delivery in the subsequent 24-hour period. Thus, the Elspot is arguably a day-ahead forward market, but it is nevertheless treated as a spot marked. The Elspot price is the equilibrium price of supply (ask prices) and demand (bid prices) which clears the market. The supply and demand curves with their consequent equilibrium (clearing price) is shown in Figure 2.4, below.

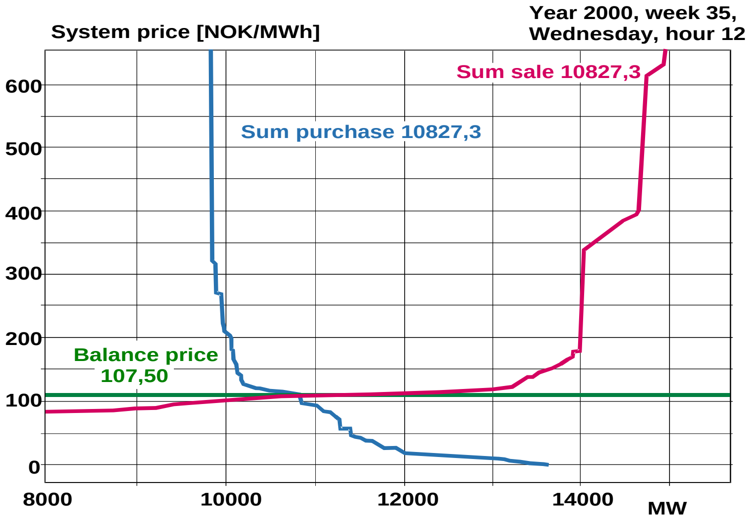

Figure 2.4 Supply & Demand Equilibrium [Wangensteen, 2003]

The same price mechanism is used to manage bottlenecks in transmission capacity by declaring two or more price areas if transmission capacity is saturated. Thus, Elspot also serves as a capacity (power) market in addition to being an energy market. The spot price is calculated assuming no active restrictions in the power grid. The unrestricted average spot price over the 24-hour period is called the System Price. When constraints in the grid between the countries are taken into consideration, local prices are obtained. Due to limitations in the Norwegian grid, a varying number of price areas (from 1 to 4) have to be declared, making the Norwegian market somewhat unique in the Nordic setting. As mentioned elsewhere, prices vary with demand and inflow. Daily and weekly fluctuations are largely due to fluctuations in demand, while the yearly fluctuation is explained both by temperature induced demand fluctuations, but also variations in inflow over the year.

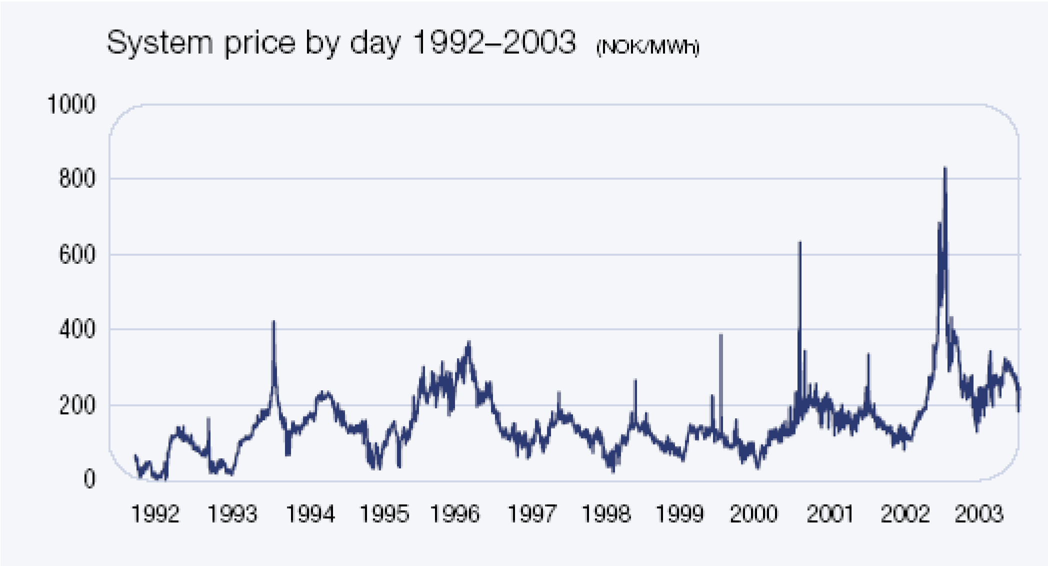

Figure 2.5 System price by day 1992-2003. [NordPool, 2004]

Figure 2.5 shows the system price from 1992 through 2003. The occurrence of price spikes is clearly demonstrated. The cyclic nature of prices over the calendar year is also evident.

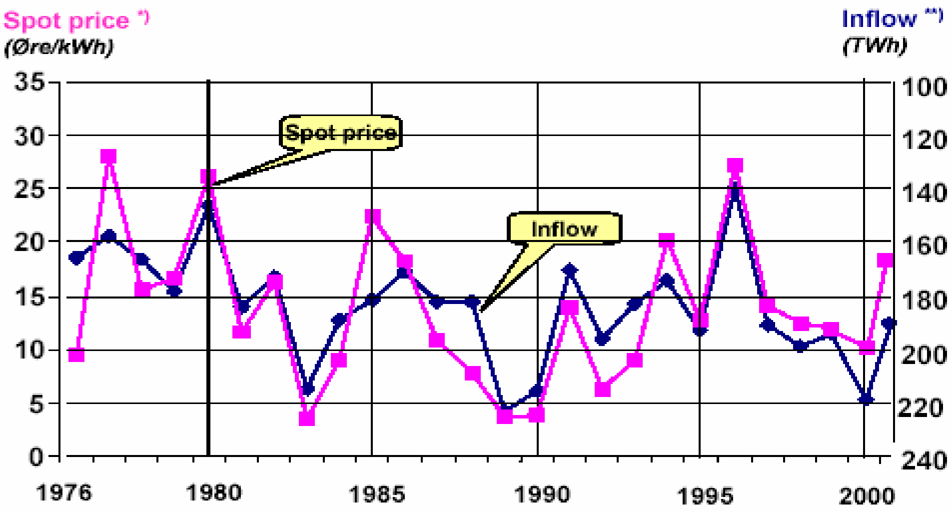

Figure 2.6 Spot Price vs. Inflow [Gjengedal]

Evident from Figure 2.6 is the extremely tight relationship between inflow and spot price development. This relationship is obviously the dominant factor in price formation and it provides an intuitive foundation for the concept of hydro scheduling.

2.3.2 The Financial Market

NordPool (then Statnett Marked AS) established a forward market in 1993 based on an auction trade system, with physical delivery of the traded power contracts. After an initial test period which focussed on the preferences of participants, the forward market was established; offering three standardised products, all based physical delivery at maturity. These three were initially base load contracts, peak load contracts, and off-peak load contracts. These products all had a time horizon of up to six months. As the Nordic power market evolved, it became evident that further development of the financial market was necessary in order to improve liquidity in the market and promote trade.

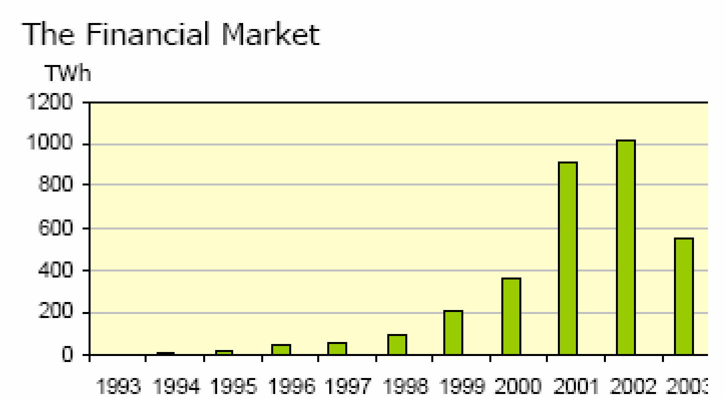

Figure 2.7 Quantity traded in NordPool's financial market

As the financial market evolved, the financial market's weekly auction trading system was replaced by a continuous trading system and contracts were changed from physical delivery to financial settlement in order to improve liquidity. The time horizon was also expanded to three years. New products were introduced, and the rapid growth in trading shown in Figure 2.7 explains the necessity of replacing the whiteboard-based trading floor with electronic trading. The latest addition to the financial market is trading in environmentally beneficial "green electricity certificates".

The financial market is also an option market. An option represents the right, but not the obligation to buy (call option) or sell (put option) an underlying product at a predetermined time (expiry) for a predetermined price (strike price). Combined with forwards and futures, options offer valuable strategies for managing the risk associated with power trading. The existence of an option market also has an effect on elasticities in the spot market. This relationship is explained in Chapter 5.

NordPool also provides an OTC (over-the counter) market. Here, Nordpool acts as an intermediary to facilitate trading of bilateral standardised contracts. In practice almost all options are traded in the OTC market.

2.4 Challenges

It should be noted that the main challenge is the fear of an *energy* shortfall, i.e. a situation where the hydro reservoirs run dry before the spring snowmelting begins. A *power shortfall,* i.e. a situation where the entire generation capacity fails to meet the aggregate demand is also a possibility, but remains another entity and is consequently not dealt with here, although that situation also would be handled by a functioning market. Nevertheless, demand spikes have posed severe challenges to generation capacity at some points.

3 Current scheduling practices for hydropower generation

3.1 Introduction

In a deregulated market like the Nordic power market, the objective of the power producer will necessarily be the maximisation of profit. In order to achieve this goal it is necessary to have a clear picture of both the costs and revenues associated with production. This paper will disregard investment planning and focus exclusively on drawdown planning of existing reservoir capacity. Nevertheless, this focus necessitates planning for three years into the future since several hydro reservoirs have multi-year capacity and the drawdown in one year necessarily impacts the drawdown for the following years.(E.g. The *Blåsjø* reservoir can store the inflow of three consecutive years). Also, in this paper, transmission pricing will be neglected in order to maintain focus on generation planning without introducing constraints caused by other variables.

In order to establish a clear path for further analysis, certain terms will be defined in order to avoid ambiguity and maintain the focus of this paper.

3.1.1 Water Values

Water values stand out as the main tool for operations scheduling in a hydropower generation plant. Water values are defined as follows [Wangensteen, 2003 a]:

"In a hydro system with reservoirs, the *water value* represents the future value of a marginal unit of water in a reservoir. For the planning entity, the decision problem will always be: Should we release water now, or should it be stored for later use. The water value which is normally calculated by means of Stochastic Dynamic Programming (SDP) is the decisive factor for that decision. If the water value is higher than the cheapest competing unit, the water should not be released. In the opposite case, the hydro unit should run."

Water values are generated by calculating backwards from a point in the future where the water value is certain using SDP. By calculating a water value week for week backwards from this given point, a temporal link is established providing an opportunity to compare today's value of stored water with tomorrow's value. Water values are a central issue in this thesis and will be described in more detail as the EMPS model is described in detail later in this chapter.

3.2 Generation Scheduling

Currently, generation scheduling is planned in several perspectives. As mentioned in the introduction, a time horizon of up to three years must be maintained in order to allow for multi-year reservoirs. The Norwegian market is a deregulated (restructured) market, and a power producer has in principle no obligation to serve any particular customer [Wangensteen, 2003 b]. The power producer will consequently maximize his profits within his given constraints. For a price-taker, this process can be reduced to three steps:

-Long term scheduling	2-3 years
-Medium term scheduling	3-18 months
-Short term scheduling	1-2 weeks

3.3 Long Term Scheduling

First, the producer must generate a forecast of the market (price development) for the planning period. Price development can be modelled as a stochastic variable which largely is governed by inflow (supply), regulation capacity (reservoirs/buffers), and power consumption (demand). Three principles may be employed in order to forecast the development of prices in the market. [Wangensteen, 2003 b]

1. One may use the prices in the futures market. However, the prices obtained by this approach render little information about correlation and price uncertainty which are both important factors for planning purposes.
2. One may use historical prices to forecasts future trends and patterns in the price development. However, the planning period for which one has a fair estimate of the supply and demand situation is typically too short to make reliable estimates of the required stochastic parameters.
3. One can use a simulation model that describes price formation

The third alternative is generally used by Norwegian hydropower producers, and the generally accepted simulation model is the EMPS (EFI's Multi-Area Power-Market Simulator).

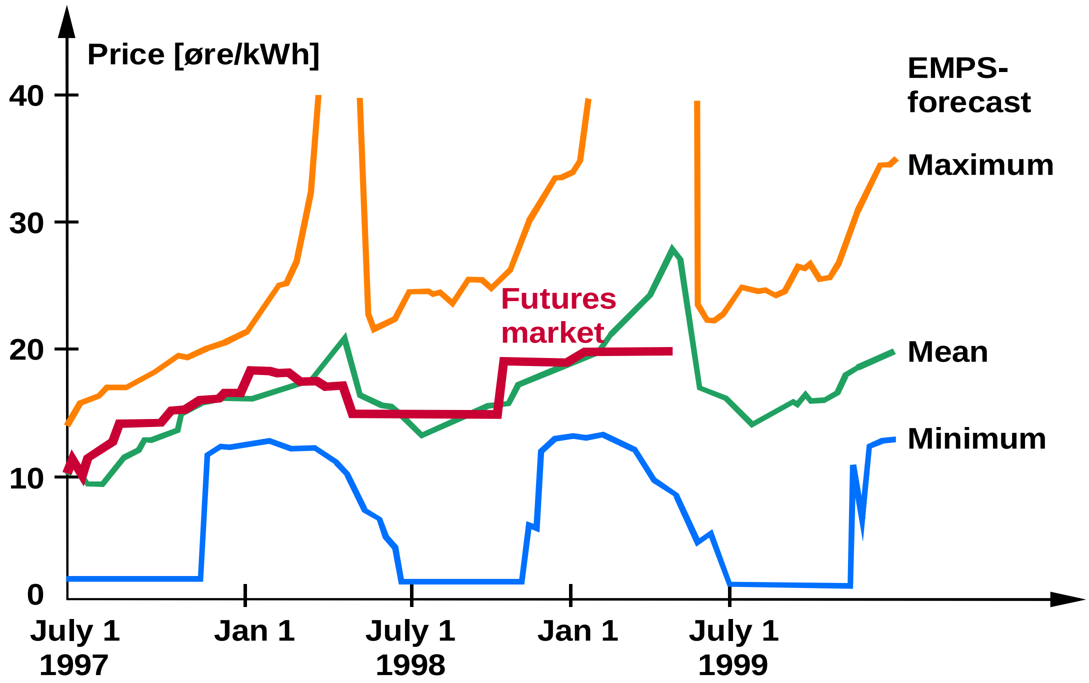

Figure 3.1 Examples of Projected prices from the EMPS-model and the futures market [Wangensteen, 2003 b]

3.4 The EMPS-Model

Norwegian power production is strongly dominated by hydropower with its mean production potential of 112,6 TWh /year and a variation span of 92 to 142 TWh/year depending on inflow. With such a level of insecurity attributed to inflow variation, marginal analyses are difficult to conduct at any level of accuracy.[EMPS, User Manual]

In order to conduct a marginal analysis of the total power system, the costs of the various means of production must be taken into account. For thermal power production, such an analysis is easily conducted by comparing the fuel costs of the various methods of production. Unfortunately, marginal costs associated with hydropower production are not so obvious. Consequently, the EMPS model consists of two modules: A strategic module where water is valued with reference to reservoir content, inflow prognoses and the market price; the second module is a simulation module. The strategic module, where also the stochastic optimisation takes place, provides a summary of water values and their respective fluctuations through the year and through varying reservoir levels. These water values are subsequently employed by the simulation module in order to calculate a proxy marginal cost which allows a comparison of the various generation plants included in the simulation.

Calculating water values is much to complex a task to carry out for each and every reservoir included in the simulation. The EMPS model simplifies these calculations by dividing the total power system into several sub-areas. These sub-areas are created by lumping several reservoirs and generation plants together and treating them as a single reservoir. The total power system comprises also one or more "coordinated systems" These coordinated systems arise from market conditions and hydrological conditions in addition to transmission bottlenecks between two areas. The principle of modelling a sub-area as a coordinated system in the EMPS model is shown in Figure 3.2 .

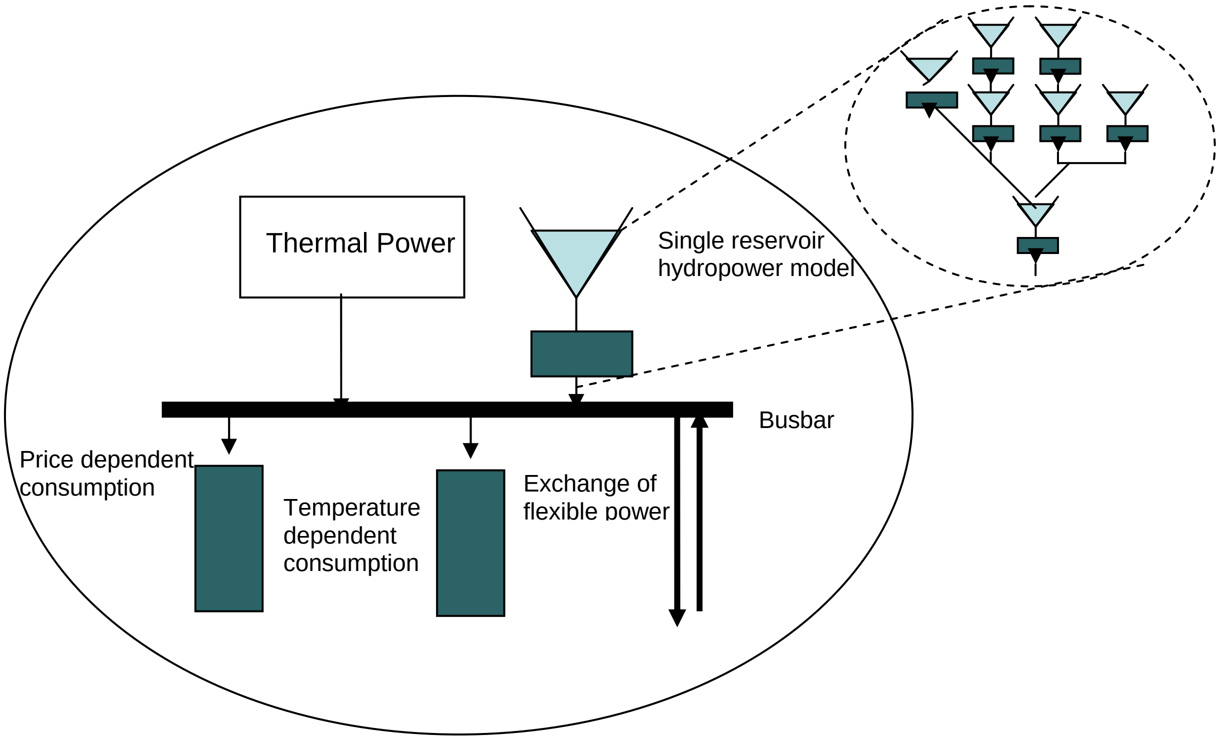

Figure 3.2 The principle of modelling a sub-area as a single reservoir in EMPS

3.4.1 The Supply Side

The EMPS model has data for the generation capacity for all the methods of power production of the countries included in the model. Also, transmission capacity in MW between production areas is entered into the model. The Sub-areas are shown in Figure 3.3.

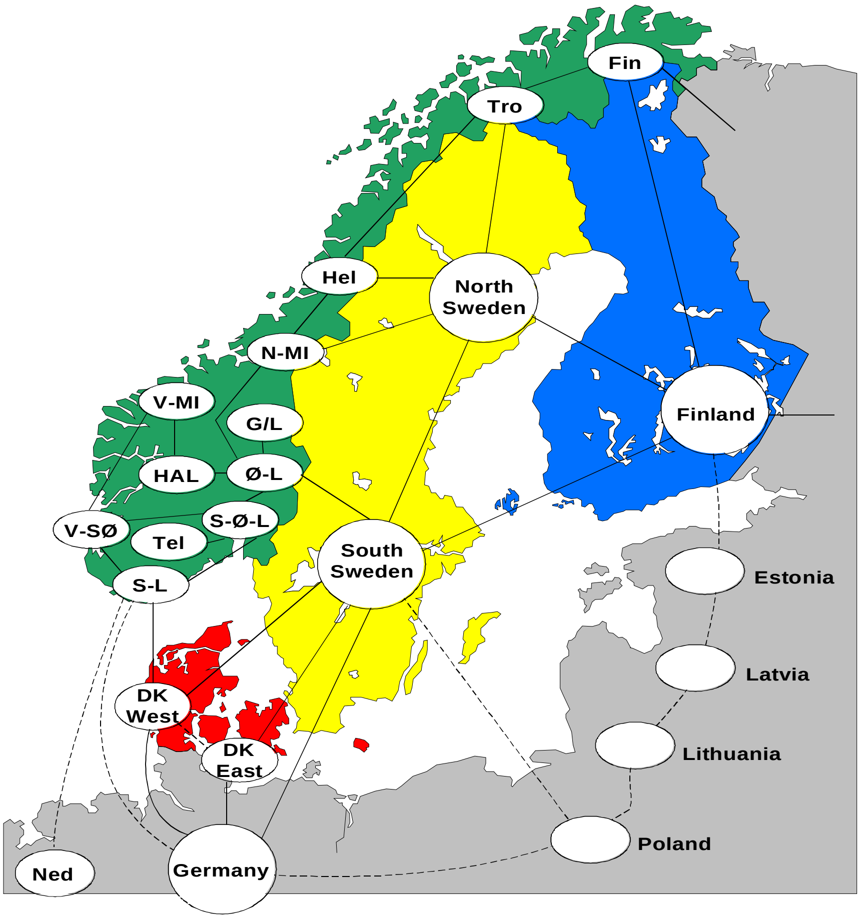

Figure 3.3 Sub-areas in the EMPS-model

Norway is divided into 12 sub-areas in the EMPS model based on hydrological and electrical characteristics. Sweden is divided into two sub-areas, where Northern Sweden is dominated by hydropower, while Southern Sweden is dominated by thermal power. Denmark is also divided into two sub-areas because of the lacking connection between Zeeland and Jutland in electrical terms. Finland is represented as one area, where hydropower production is given as a production series for the inflow period in question.

Thermal power systems are subject to variable production costs due to the projection of fuel costs which is given as an exogenous value. For a reservoir-based power plant (as opposed to a run-of-river plant) the "fuel costs" will depend on the drawdown of each individual reservoir today and in the future. Today's use of available water will impact the value of the reservoir content in the future. This valuation is based on, among other factors, today's market price and inflow conditions vs. these same conditions in the future. Projecting future reservoir levels is associated with a high degree of uncertainty and variations will span from the driest to the wettest year in the historical inflow database. In this thesis a database of 70 years (1931-2000) is used.

From the above discussion, it is evident that a given reservoir level has varying corresponding water values throughout the year. This relationship can be shown by isoprice curves as shown in figure 0.4. The figure shows clearly that there is an inverse relationship between reservoir level and water value. Also, the water value varies greatly depending on the time of year

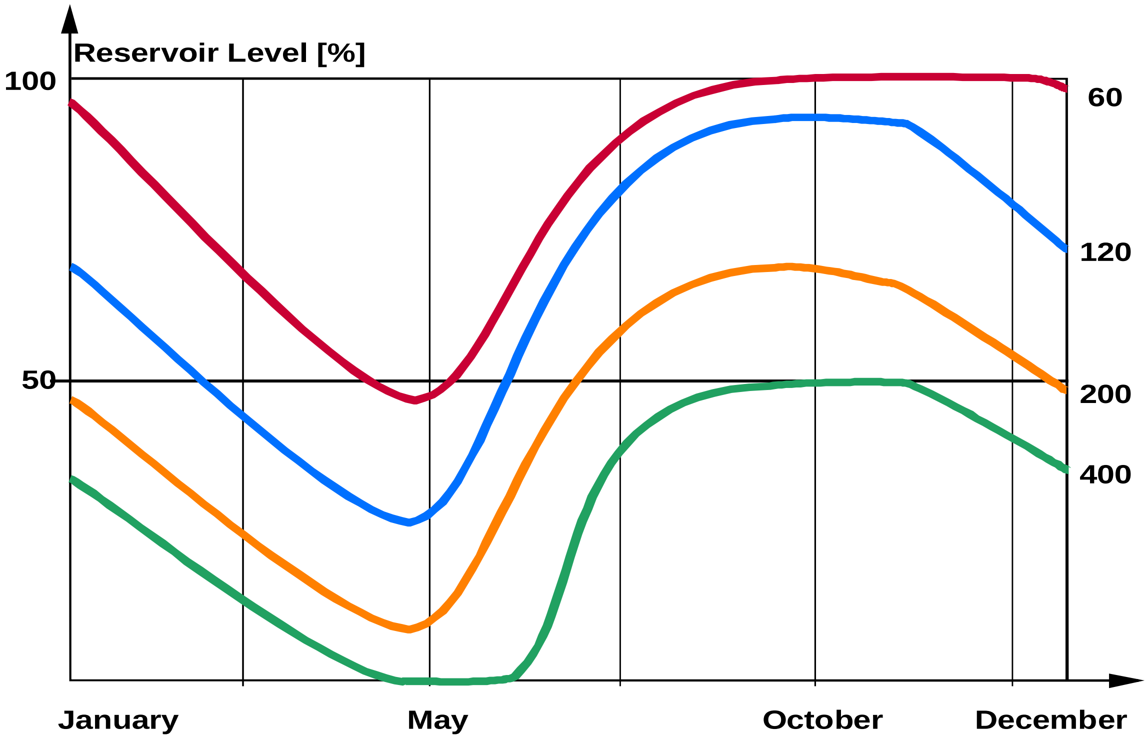

Figure 3.4 Iso-price curves for various reservoir trajectories

Water values for the individual sub-areas can be calculated when the production system has been divided into the desired number of sub-areas. These calculations are carried out in the strategy module where the expected value of stored water is prefabricated as a function of the reservoir level and the time of year. The calculations are carried out by backwards stochastic dynamic programming. Typically, a planning horizon of 2-3 years with a resolution of 1 week is used in these calculations.

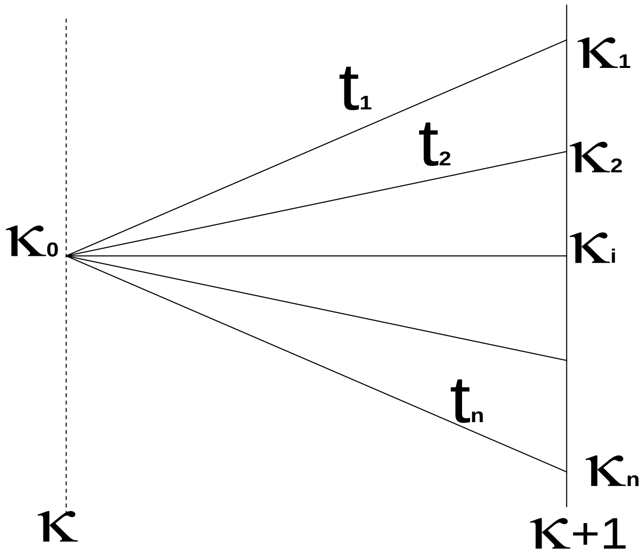

Figure 3.5 **Calculating the water value at point K_0**

When calculating the water values, the reservoir is split into several reservoir points. For each reservoir point, the water value is calculated for the beginning of the week as shown in (1):

$$K_0 = \sum_{i=1}^{n} P_i \bullet K_i$$

Equation 1

K_0 = Calculated water value at the beginning of week *n* for a given reservoir point.

Pi = The probability for inflow *I* to occur.

K_i = The water value at the end of week *n* for inflow *i* given the reservoir level subsequent to optimal production

In the EMPS model the calculations are carried out in an iterative process where the water values of the individual sub-areas are calculated independently. Since the water value in one sub-area also depends on the situation in other sub-areas active in the same markets, all sub-areas must be provided information about the transmission capacity to the other respective sub-areas. This information is provided in every iteration by the correction of market values for firm power and random power for each sub-area. Transmission costs and losses can be adjusted in the model. Ultimately, the iteration process consists of three main steps.

1. Water values calculation : Water values are individually calculated for each sub-area on the basis of a local aggregate reservoir simulation. The sub-area is modelled so that it incorporates the effect of the other sub-areas in the system.
2. Simulation: The operation of the coupled system is simulated with reference to the latest available water values. Usually, the operation is simulated by using aggregated hydropower models for each sub-area. It is possible to use a detailed drawdown distribution model for this simulation. However, this level of detail increases calculation time without necessarily yielding a better feedback process
3. Feedback: The results from the last simulation are used to modify the respective markets in the sub-area before the next water value calculation

The basic principle of the EMPS model relies on user controlled calibration in order to achieve an optimal result. Consequently, the user may modify parameters controlling feedback in the "outer loop" in order to vary the form and level of feedback. The user must base the modification of these parameters on simulation results. However, for many systems, this calibration consists of a verification of the results and sometimes a minor adjustment of the feedback parameters.

When calibrating the EMPS model, the main concerns of the user are reservoir management and operation dependent costs. In this instance, reservoir management refers to the intercourse between the aggregated reservoirs of the respective sub-areas. Important inputs may be factors such as distribution of reservoir surplus, the drawdown of well-regulated reservoirs in dry years, autumn filling etc. Changes in the resulting profit/costs provide an indication of the performance of the calibration process.

When the possibilities for power transmission between the various sub-areas are limited (e.g. because of transmission bottlenecks), one or several sub-areas will be isolated as a distinctive price area. In the event that market issues, hydrological characteristics or capacity concerns oppose such isolation, a converging price will be set for the total power system. Consequently, a supply function will be constituted based on the water values and the marginal cost function of thermal power production.

The supply function will vary as a result of modifications of the underlying premises. For instance, the EMPS model allows the user to define area distributions which are different from the one previously described. As an example, the resources of a large market participant may be defined as an individual sub-area. The user may also modify the level and composition of power generation in different countries. Thus, one may allow for shutdowns of and investments in production capacity. The transmission capacity between areas may be modified, allowing the user to make several approaches to bottlenecks and to see how grid development influences the total system. Also, changes in cost levels can be made, i.e. allowing for a price hike for coal as the result of a suggested environmental tax. Finally, it is possible to gauge how reservoir levels and circumstances will impact the aggregated system.

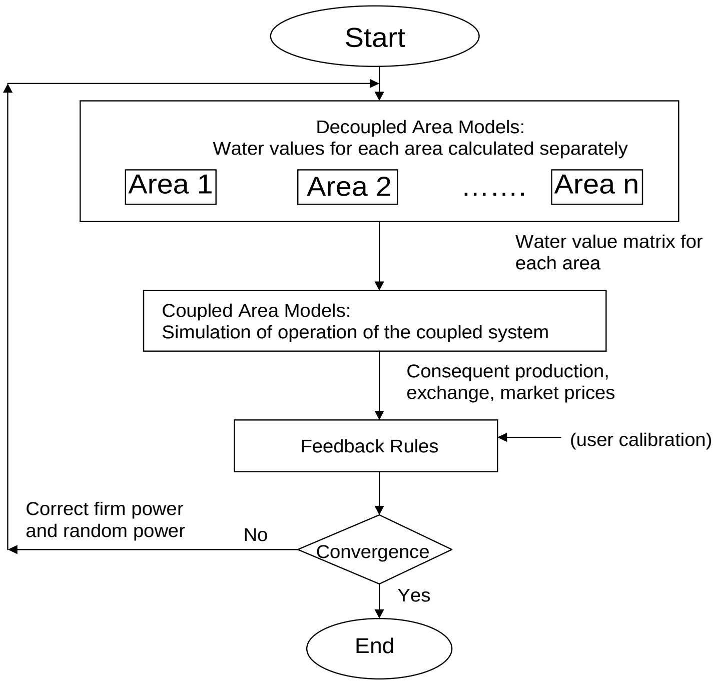

Figure 3.6 The principle behind water value calculations in the EMPS-model

3.4.2 Demand Side

In the EMPS model, demand is generally defined as firm power or random power. Firm power comprises contractual deliveries for general use or power intensive industry. The degree of freedom in this system is associated with the sale of power to cover flexible consumption, such as boilers; non-guaranteed industrial power supplies; and light oil substitution. This flexible consumption defines the random-power market. This market also comprises interaction capabilities with other coordinated systems.

The demand side is modelled on basis of historical consumption data for the relevant countries. Projections are made for increases in consumption, and the resulting demand is entered into the model as a constant. The EMPS model has typically been operated with demand set as a constant, i.e. independent of market prices. It is possible to define a price dependent demand function which reflects the short-term price elasticity in the market. Some aspects of this thesis rely on the use of price dependent demand functions defined through elasticity. Unfortunately, representative data documenting elasticities for various consumer groups are not readily available, so this input is usually avoided. However, it is assumed that the price will not increase beyond a certain level without some sort of intervention. Consequently, a rationing price is typically set at 0,70 NOK/kWh. In the project paper preceeding this thesis, simulations were conducted with other values for the rationing price. These results are summarized in chapter 6.

The EMPS model allows for modifications of the premises of the demand function. Thus, it is possible to change the level of consumption and the level of projected consumption growth in order to match market projections or to model specific scenarios such as critical inflow shortages. Demand can be modelled as step functions or exponential functions in order to reveal the impact of various elasticities. Finally, one may change the prices of various energy carriers and also change the transmission capacity to/from the coordinated system in order to reveal how prices respond to such shifts.

3.4.3 The Total System

When the water value for each sub-area is established, the operation of the aggregate system may be simulated. The water values indicate how much energy to produce given the market conditions in the area. The water values by themselves do not indicate how drawdown is distributed across the reservoirs. A simulation of the total system, however, will provide a basis for the distribution of drawdown in the total system.

The historical inflow data years can be dealt with in parallel or in series. Short term simulations uses the current reservoir situation and applies the inflow data in parallel in order to generate projected reservoir levels based on inflow spanning form the driest to the wettest year. Long term simulations (10-20 years) will treat the data serially so that the reservoir surplus at the end of one year is transferred to the beginning of the next year.

Ultimately, the simulated hydropower production is registered in time series of e.g. weeks or years. These registers may be broken down to single generation plants, sub-areas or the aggregated system. Likewise, Thermal power production, imports/exports rationing, spillage etc may be registered. The model's management of the respective reservoirs may also be monitored. Thus, one may project power transmission between sub-areas and aggregated areas. Economic results such as profits marginal costs and marginal utility may also be registered. It is also possible to assess environmental costs and benefits associated with the aggregated power system, e.g. through the substitution of coal-fired thermal power production by hydropower production.

Obviously, accurate forecasts rely intensely on hydrological data and accurate meteorological forecasts. Inflow series representing the last 70 years are employed in order to determine the stochastic variation of inflow. Consequently, the power sector spends a lot of resources on the gathering and analysis of meteorological and hydrologic data

3.5 Medium Term Scheduling

Second, based on the forecast, the producer must employ a production strategy that maximizes the expected profit for the planning period adhering to the given constraints. Here a deterministic approach is used and water value calculation takes a central place. Tools such as the SESONG model are among the tools used in order to narrow the system calculations from the EMPS model and to obtain water values for the individual reservoirs.

The SESONG model optimises the value of the water within one system of reservoirs and generation stations based on an idealized reservoir level. This is the reservoir level which one aims to achieve at the end of the given period. This idealized reservoir level is found in the drawdown distribtioun in the EMPS model. Then, the SESONG model calculates the water value of each reservoir. The calculation of these water values is carried out by firt calculating the marginal value of stored water. Then, production is optimized for the given production prognosis. Finally, expected revenues are calculated on basis of expected price and inflow alternatives. It should be noted that the SESONG model simulates production for an entirely inelastic market, using the price data provided by the EMPS model.

3.6 Short Term Scheduling

On a daily basis, the current values for price, water values and reservoir content are analysed by means of programs such as SHOP (Short-term Hydro Operation Planning) in order to determine initial generation schedules and bids in the spot market. Consequent bids are also made for the regulating market. Short-term planning must in addition to placing the best bids to match the current market equilibrium also take into account revisions of generating stations and transmission lines in order to maximize revenue. Finally, the producer must update his forecasts and consequently his production plans whenever new data suggests a change. The SHOP model can be set at any resolution down to 1 minute in order to provide adequately precise data

4 Characteristics of energy prices

Here, a brief description of some of the central characteristics of future contracts in the Nordic energy market is presented. The key factors are:

1. *Storability*
2. *Mean Reversion*
3. *Volatility*
4. *Price Variations*
5. *Elasticities*

Each of the first four factors will be briefly described in order to capture the essence of their respective contribution to the composition of prices in the Nordic market. Then, in the next chapter, the concept of elasticities and their implications in the Nordic market will be dealt with at length.

4.1 Storability

Electrical power is a product that is not readily storable, so production and consumption must consequently be simultaneous. Limited transmission capabilities further curtail the distribution possibilities of generated power. As a consequence, arbitrage opportunities in the spot market will practically be non-existent. [Lucia and Schwartz, 2002]. Power Consumers have no means of storing electrical power, whereas producers of hydropower can store power as water in their reservoirs. Nevertheless, producers must manage their limited reservoir capacity so to best face changes in demand over time. Consequently, in the Nordic market, reservoirs are filled and depleted depending on inflow and power demand.

4.2 Mean-Reversion

Since demand and inflow is cyclical over a period of one year, mean-reversion is thought to be the best method for modelling energy prices. [Pilipovic, 1998; Clewlow and Stickland, 2000] In practice, mean-reversion implies price fluctuations in the short term which converge to an equilibrium price in the long run. This conclusion is evident from the fact that a high energy price will allow producers with a high marginal cost to enter the market resulting in increased supply and lower prices. Conversely, low prices will force the same producers out of the market, thereby limiting supply and increasing prices. A central characteristic of mean-reversion is its inherent half time. The simplest form of mean reversion can be expressed as:

$$dx = \alpha(x_m - x)dt$$

Equation 2

Where:

x	Natural logarithm of the spot price
x_m	Long-term mean price
α	Mean reversion rate

4.3 Volatility

Changes in energy prices are stochastic and the volatility measure provides an indication of the magnitude of these changes. Volatility is also prone to change itself and consequently should be modelled as a multifactor model with both temporal and stochastic variables [Pilipovic, 1998]. However, it is frequently presented as a constant with a high value for the volatility of the spot price. Lucia and Schwartz (2002) present a yearly average of 189% in the period from 1993 to 1999. Forward contracts display a significant reduction of volatility as time to expiry increases. These characteristics are explained by the limited storage capacity discussed earlier [Pilipovic, 1998].

4.4 Price Variations

As a result of the limited storability, electricity prices display several interesting cycles or patterns over various periods of time. In addition to the annual fluctuations caused by seasonal and inflow variations, daily and weekly patterns are also evident. These patterns are easily explained by the reduced load at night and in the weekends. Furthermore, severe price increases, or “price jumps” are frequently seen in the energy market. A measure of price extremity is kurtosis. Kurtosis is a parameter that describes the shape of a random variable’s probability distribution, and can be described as follows:

$$Kurtosis = E\left[\left(S_t - \bar{S}_t\right)^4\right] \qquad (2)$$

Equation 3

Where: S_t = The spot price at a given time
$\bar{S}$ = The mean spot price

Lucia and Schwartz (2002) find a kurtosis of 3,5 for Elspot prices in the period from 1993 to 1999. A normal distribution displays a kurtosis of 3, so this leptokurtic distribution indicates a higher probability for extreme prices than in a normal distribution. Moreover, the same paper reveals a positive skewness for the data in question. A positive skewness indicates a higher probability for extremely high prices than for extremely low prices.

Lucia and Schwartz used the daily system price to obtain the result mentioned in the previous paragraph. In order to demonstrate the extreme nature of the Elspot prices in the winter of 2002 to 2003, a similar test was conducted using the similar data from 1993 to 2003, thereby extending the range another four years to include the dry winter of 02-03. The test version of the statistical program Minitab Version 13 was used to generate the consequent results which are quite revealing. From 1993 to 2003, the kurtosis of the spot price is an extremely high 12,4.

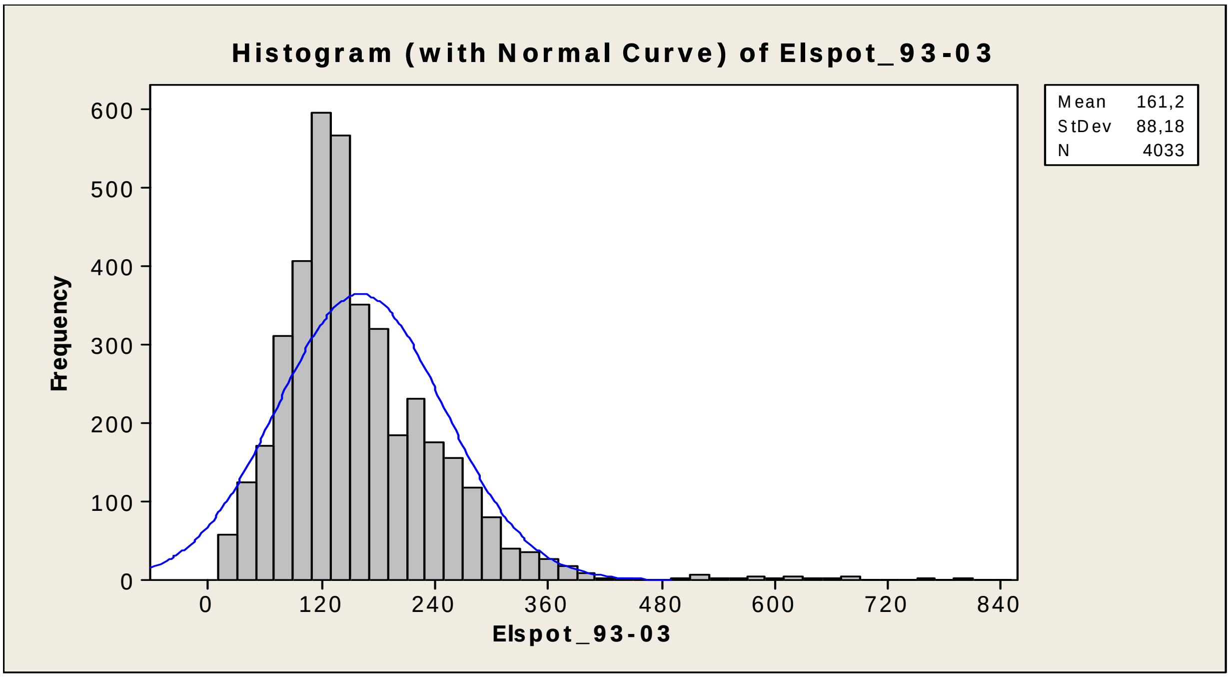

Figure 4.1 Frequency of Prices – 1993-2003

At first, these results appear extreme. In order to ascertain their validity, a similar test using the exact same data as in Lucia and Schwartz [2002] was conducted. The results from both tests are summarized in Table 4-1.

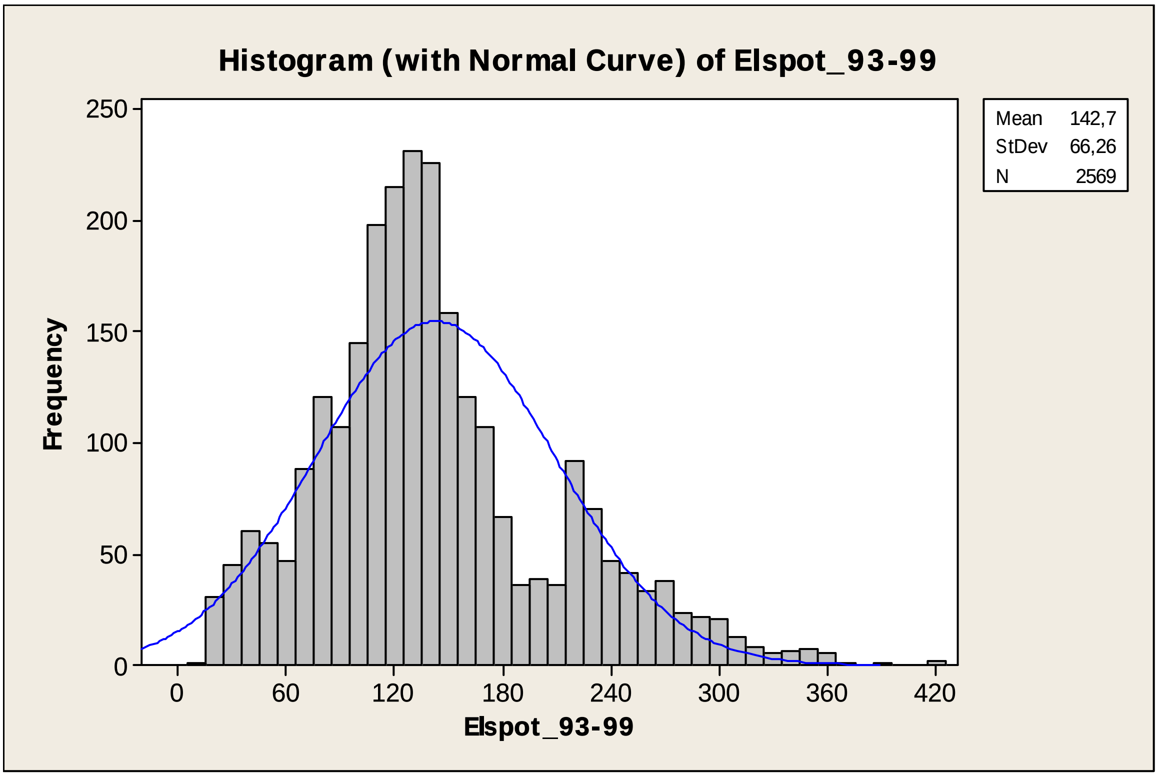

Figure 4.2 Frequency of Prices – 1993-1999

Table 4-1 Summary of statistical results for elspot prices 1993-1999 and 1993-2003

Variable	N	Mean	StDev	Min./Max	Skewness	Kurtosis
Elspot_93-99	2569	142,67	66,26	14,80 / 423,38	0,75	3,55
Elspot_93-03	4033	161,23	88,18	14,80 / 831,41	2,12	12,38

It is evident that the results for the data set 1993-1999 exactly match the results of Lucia and Scwartz. Consequently, the results for the data set 1993-2003 should also be valid.

5 Elasticities

5.1 Elasticities defined

"The price elasticity of demand is a measure of the responsiveness of demand to price changes. Technically, the price elasticity is the relative change in demand divided by the relative change in price. In other words, if a 10% price increase leads to a 5% reduction in demand, the elasticity is -0.5" [Schotter, 2001]

5.2 Elasticities as exponentials

Suppose

$$y = x^{\alpha}$$

$$\frac{dy}{dx} = \alpha \cdot x^{\alpha-1}$$

$$\frac{x}{y}\frac{dy}{dx} = \frac{x}{y} \cdot \alpha \cdot \left(x^{\alpha-1}\right)$$

$$\frac{x}{y}\frac{dy}{dx} = \alpha \cdot \left(\frac{x^{\alpha}}{x^{\alpha}}\right)$$

$$\frac{\%\Delta y}{\%\Delta x} = \alpha$$

Therefore, α is an elasticity.

Equation 4

The above relationship is necessary to understand in order to define elasticities in the EMPS model, since elasticities are entered into the model as α, defined in Equation 4

5.3 Options and Elasticities

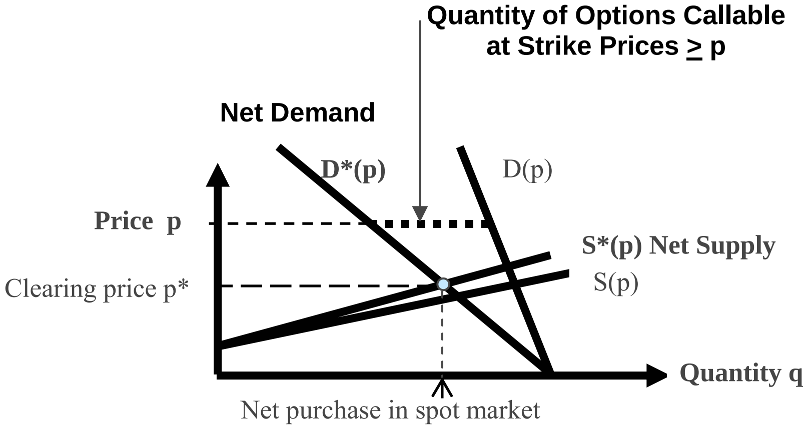

Figure 5.1 Options and elasticities [Chao and Wilson, 2004]

The effect of options is to tilt the net demand and supply curves, whereas fixed-price fixed-quantity contracts shift these curves. This tilting of the demand curve is analogous to increasing demand elasticity. In a very inelastic market, such as the Nordic power market, this increased elasticity may prevent spiking prices.

6 Simulations

6.1 Introduction

When working with a comprehensive model such as the EMPS-model, some time is required in order to establish a working knowledge of it. The author has acquired some knowledge of the model while using it in conjunction with this thesis and the preceding project thesis. In both cases, focus has been directed towards marginal changes in production due to price signals. In the project thesis, an attempt was made to gauge the change in production and consequent value of lost load due to a change in *the intervention price*. Since these simulations also were conducted for the dry years used in this thesis a summary of the result is provided below in Figure 6.1. This summary demonstrates how the EMPS-model projects the changes in production due to the intervention price (or rationing price) and shows how production may be slightly shifted from a moderately dry year to a very dry year given the correct intervention price.

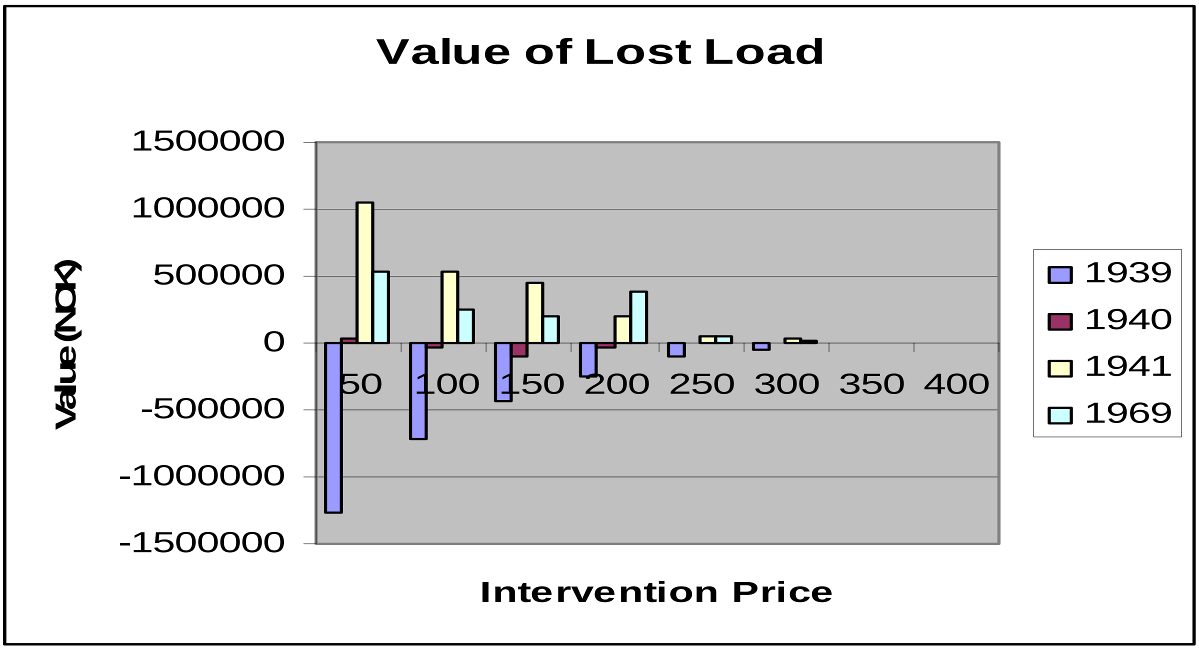

Figure 6.1 Value of Lost Load at different intervention prices

In this thesis, the focus has been the effect on production by changing demand elasticities. The elasticities were set in the SAMINN module of the EMPS-model. Two general categories of simulations have been carried out. First, simulations were conducted to see how the production quantity varies with elasticity. Then, simulations focussing on price formation were conducted. An elasticity of -0.05 was used as the reference value, in accordance with values used by Berg and Bye (2003); and Johnsen and Lindh (X.X). Elasticities of -0.10, -0.15 and -0.20 were used as comparisons throughout the simulations in the hope of obtaining effects of some magnitude. Particular focus was placed on the dry years of 1939, 1940, 1941 and 1969. Figure 6.2 shows the relative dryness of these years compared to the fairly normal years of 1998-2001. Also, focus was directed to the years 1998, 1999 and 2000. These are years with consumption levels comparable to current consumption which is also shown in Figure 6.2. This demand consequently matches the demand level defined in the EMPS model, and are consequently used as proxies for the current demand situation.

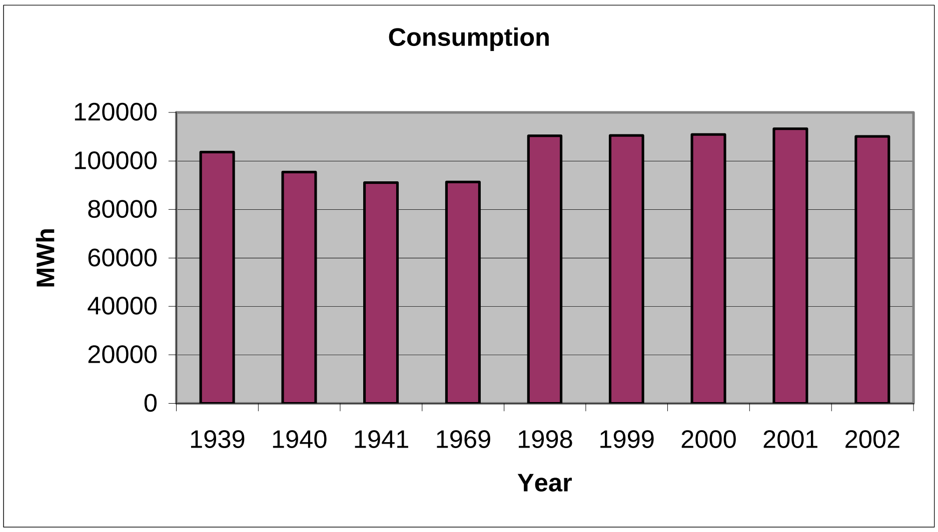

Figure 6.2 Consumption per annum. Data from Statistics Norway

6.2 Production Simulations

6.2.1 Reference Simulation

In order to establish a reference production level, a simulation for with an elasticity of -0.05 was conducted for the years 1939, 1940, 1941 and 1969. The results are given below in Figure 6.3. These values provide a base for comparison with values obtained by conducting simulations for other elasticities. In order to distinguish more clearly between the simulated years, a cumulative plot of the same data is provided below in Figure 6.4.

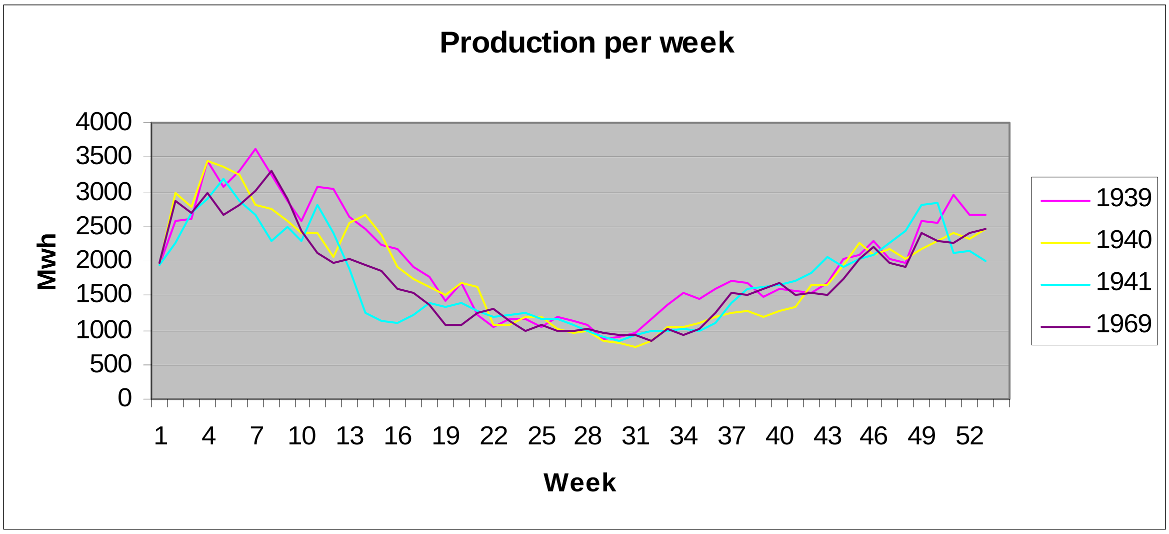

Figure 6.3 Production per Week

A cumulative plot of production for each of the four dry years is also included in Figure 6.4 in order to provide a comparison of how the generation varied relatively throughout the year. Here the extremity of the situation in 1941 becomes apparent as it followed the only slightly wetter year of 1940 and consequently suffered from already fairly depleted reservoirs. Cumulative plots are used extensively in this chapter in order to demonstrate the development of inflow and production of the respective years. Also, cumulative plots provide clear distinctions between compared scenarios.

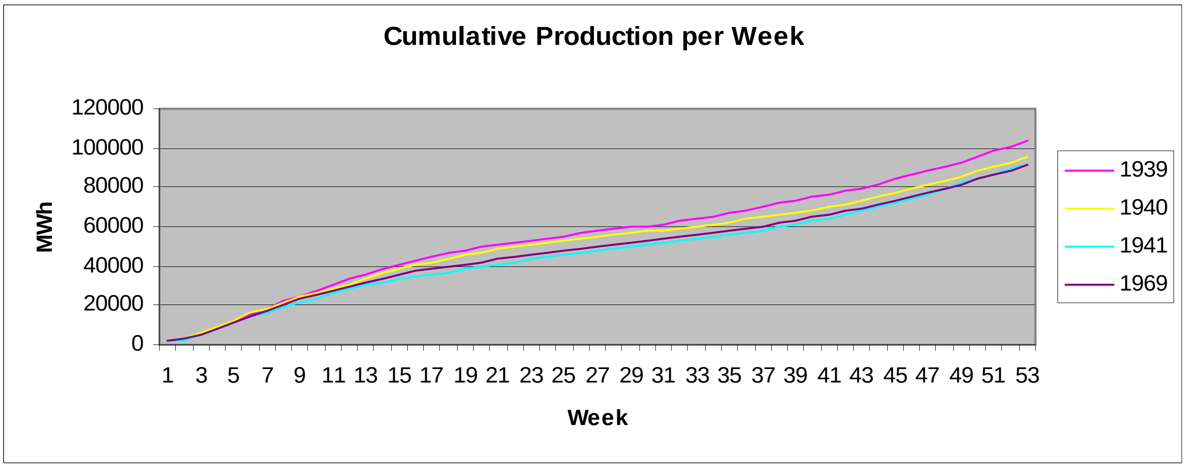

Figure 6.4 Cumulative Production per Week

6.2.2 Comparisons

As mentioned earlier, simulations were conducted for four elasticities for each of the four years mentioned earlier. Results for data sets corresponding to their respective elasticities for the same simulated year were plotted together so that their effects may be compared. Evident from Figure 6.5, below, the differences are so small that they hardly appear on the plot.

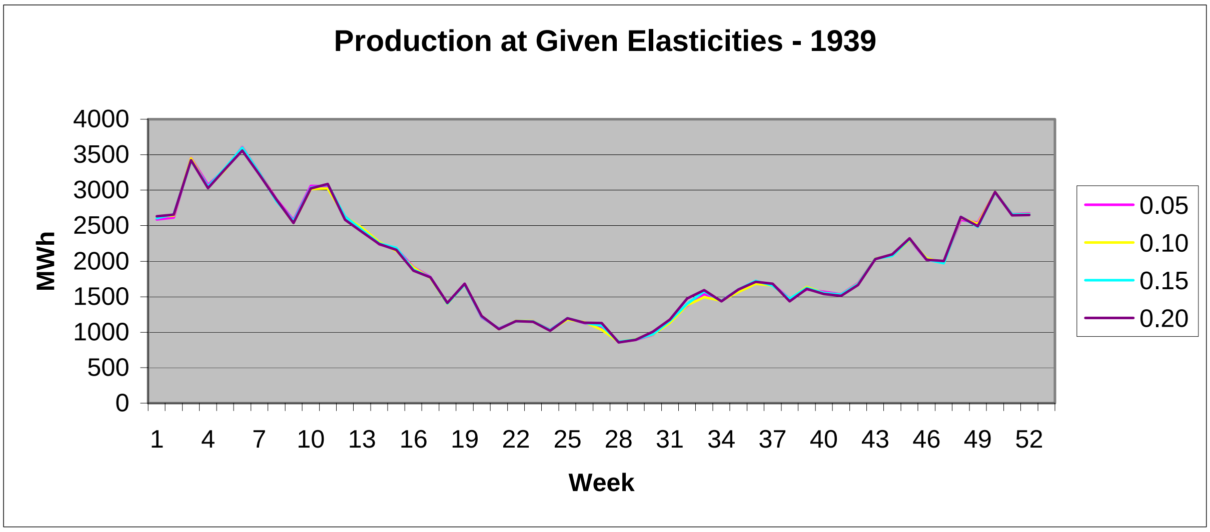

Figure 6.5 Production at Given Elasticities – 1939

In order to make a clearer distinction between the values, the cumulative values of the production at each elasticity were generated and appear in Figure 6.6.

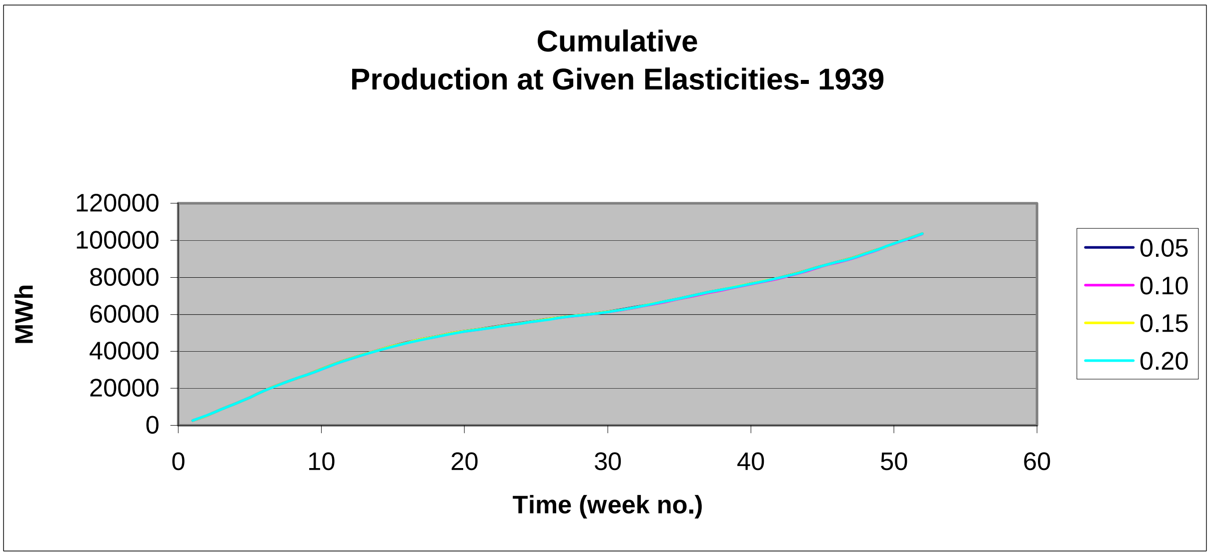

Figure 6.6 Cumulative Production at Given Elasticities - 1939

However, these values are even closer together and provide no information about the change in production due to elasticities. Consequently, the reference simulation with the elasticity set at -0.05 was used as a reference. Then the difference in production between the data sets representing 0.10, 0.15 and 0.20, respectively, and the reference was found. These differences are found in Figure 6.7, where Delta X means the difference between series X and the reference series.

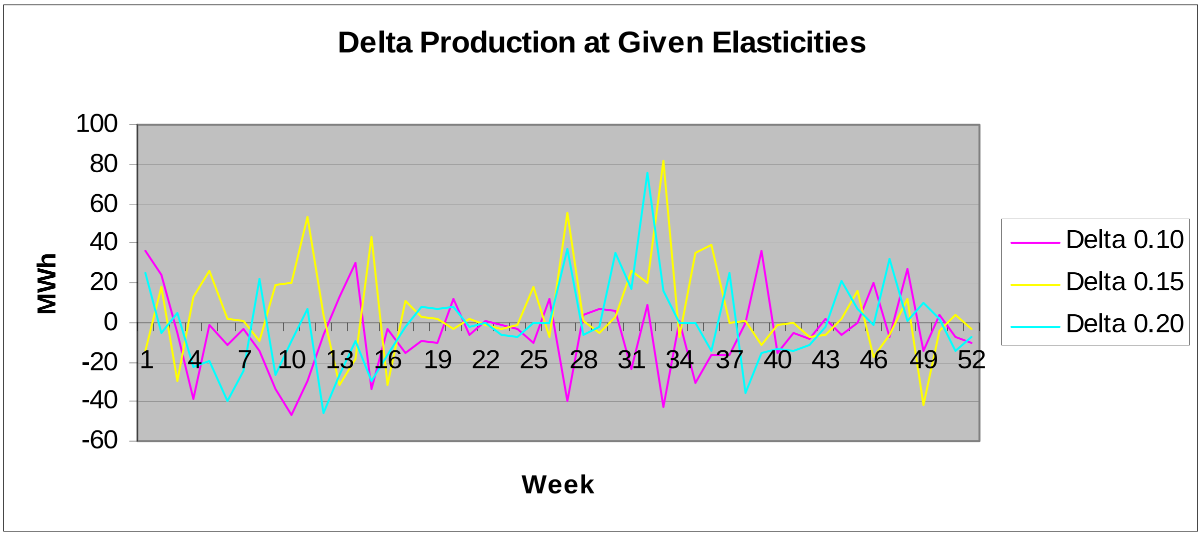

Figure 6.7 Delta Production at Given Elasticities

This plot provides a lot more information, and shows clearly how the absolute value of the difference (Delta) between the respective data series and the reference series increases as the absolute value of the elasticity increases. (The negative sign has been omitted in the diagrams for purposes of brevity). This result is clearly in correspondence with the theory. In order to find the accumulated effect of these differences a plot of the cumulative "deltas" is provided in Figure 6.8.

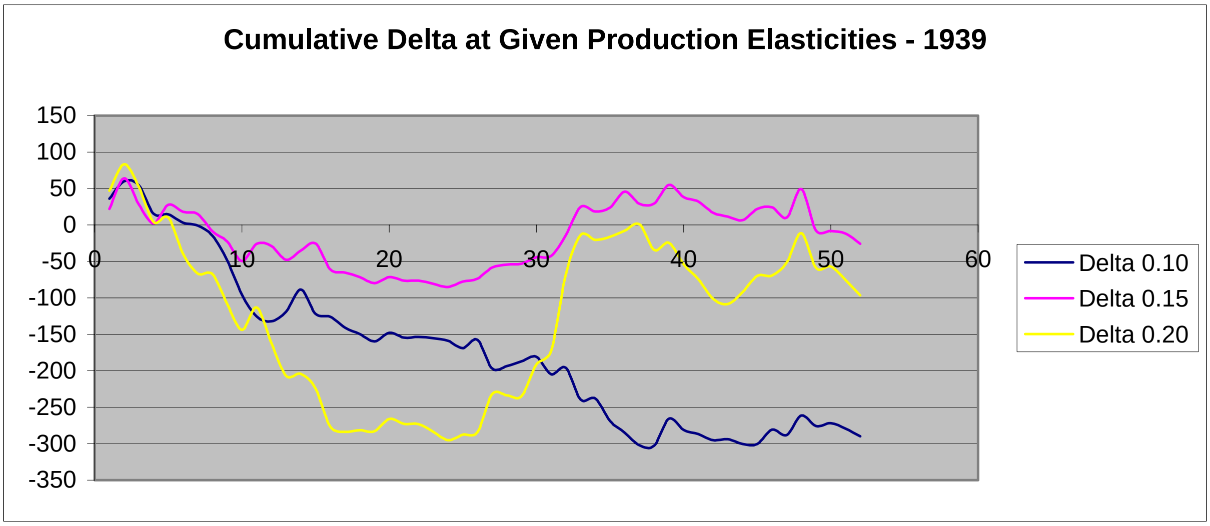

Figure 6.8 Cumulative Delta Given Production Elasticities-1939

This plot shows clearly that the difference in production increases in absolute terms with increasing elasticity. Moreover, Figure 6.8 demonstrates that an increased production contributes to a tendency of reduced production in a dry year. This result also agrees well with the theory that high prices will result in decreased demand as demand elasticity increases.

6.2.3 Results for 1940, 1941 and 1969

From the previous section, it is obvious that the most revealing results are obtained by plotting the data as described and shown in Figure 6.8. Consequently, these graphs are shown below and subsequently commented upon.

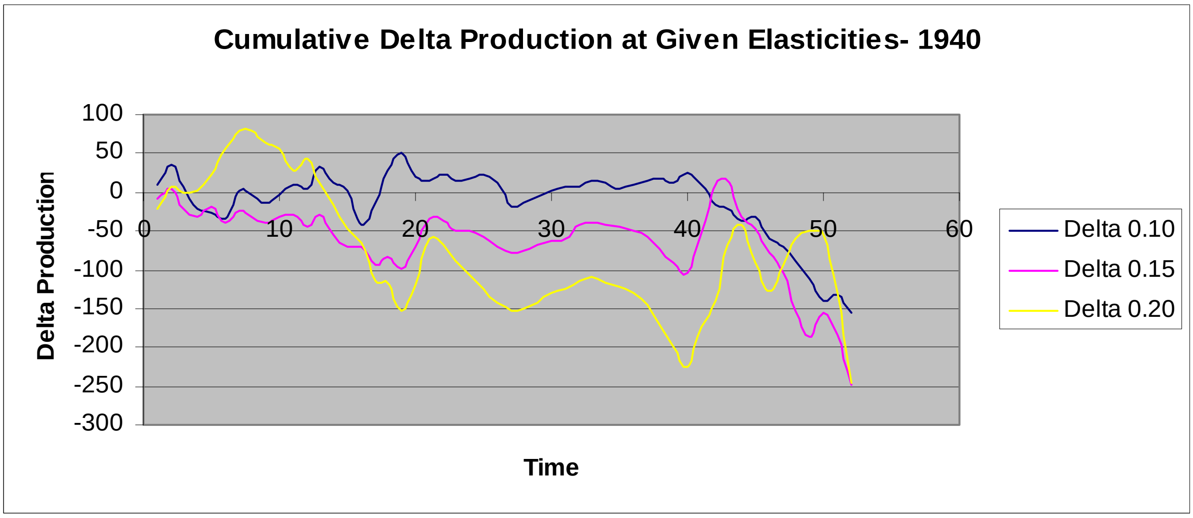

Figure 6.9 Cumulative Delta Given Production Elasticities-1940

Figure 6.9 demonstrate more or less the same results as found in Figure 6.8, although the tendency is not equally clear. However, the correlation between a higher elasticity and a higher delta is obvious.

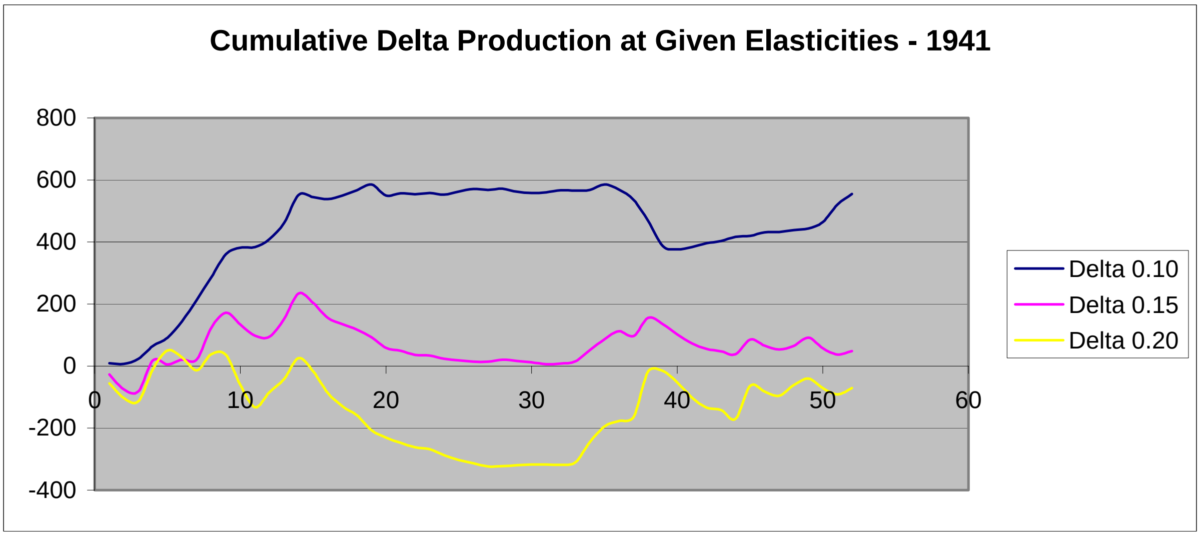

Figure 6.10 Cumulative Delta Given Production Elasticities-1941

Figure 6.10 displays some interesting results. Here, the values of data set representing the elasticity of -0.10 are in fact higher than the corresponding values representing the reference elasticity of -0.05, and thereby contradict the theory. There are no clear explanations for this particular result, but also here the tendency of decreased consumption as the absolute value of the elasticities increase is evident, and in accordance with the theory.

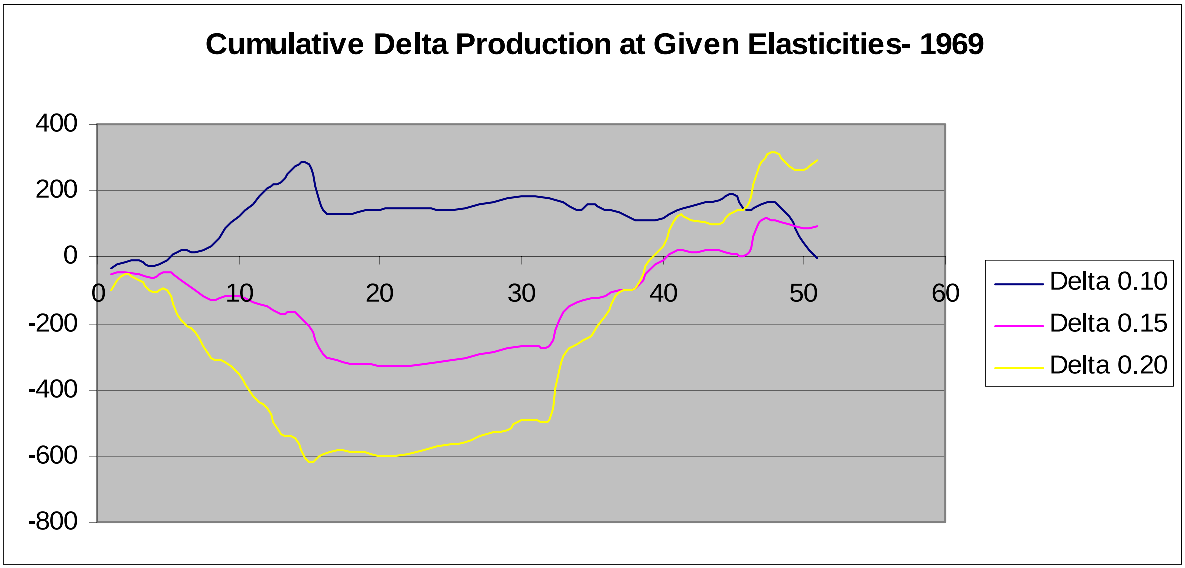

Figure 6.11 Cumulative Delta Given Production Elasticities-1969

Figure 6.11 displays to an extent the same characteristic as mentioned about
Figure 6.10 with the value of delta 0.10 being positive, although only marginally so. Also here, the relationship of increased delta with increased elasticity in absolute terms is evident. Interestingly, the plot of the values for Delta -0.20 end up at a higher value than Delta -0.15, which again is higher than Delta -0.10. This result suggests that the inflow situation improved dramatically toward the end of the year, resulting in decreasing prices and a faster growth in consumption given high price sensitivity. However, data showing inflow for 1969 with a sufficiently high resolution is unavailable to corroborate this supposed inflow gain.

Simulations of production at various elasticities (for the same inflow years and elasticities) were also conducted with aggregate demand set at 110%, and 120% of the current value. These results are omitted for the sake of brevity since they do not represent any significant new results except for a higher magnitude of difference in production for the respected Deltas. Figure 6.12, representing the inflow data from 1940, is included as an example. Here, similar results to Figure 6.9, also representing 1940, are observed; the main difference being the magnitude of the difference of production.

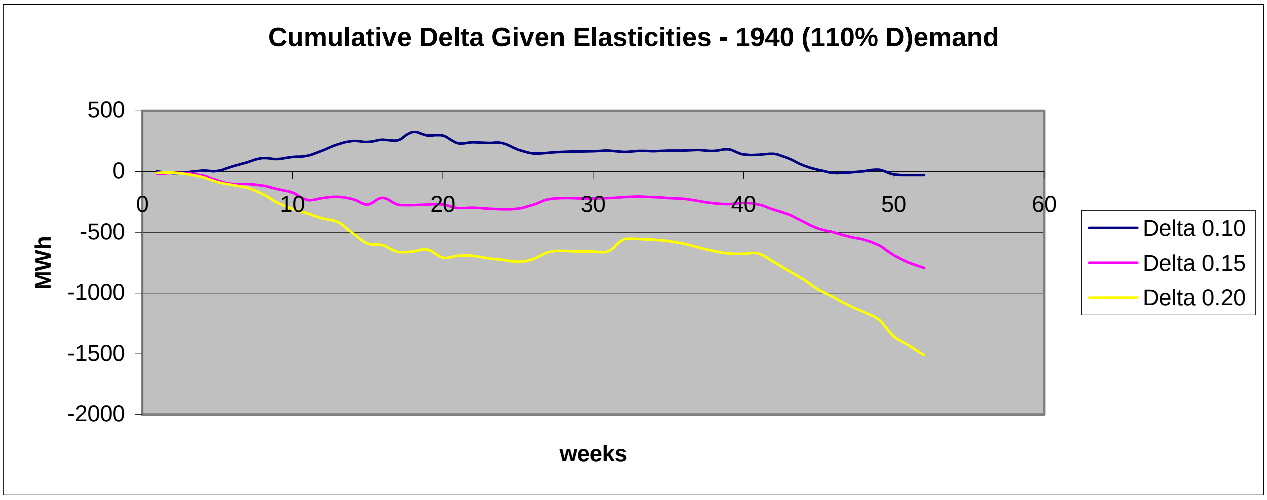

Figure 6.12 Cumulative Delta Given Elasticities-1940 (110% Current Demand)

6.3 Price Simulations

In addition to the above production simulations, price simulations were also carried out. As mentioned in the introduction, these simulations were initially carried out for the years 1998-2000 so that the projected prices could be compared with observed prices from Nordpool's Elspot market. This comparison will provide an idea of how accurate the projections (with the current input values and feedback factors) are for normal years. Finally, price simulations were conducted for the dry years 1939, 1940, 1941 and 1969.

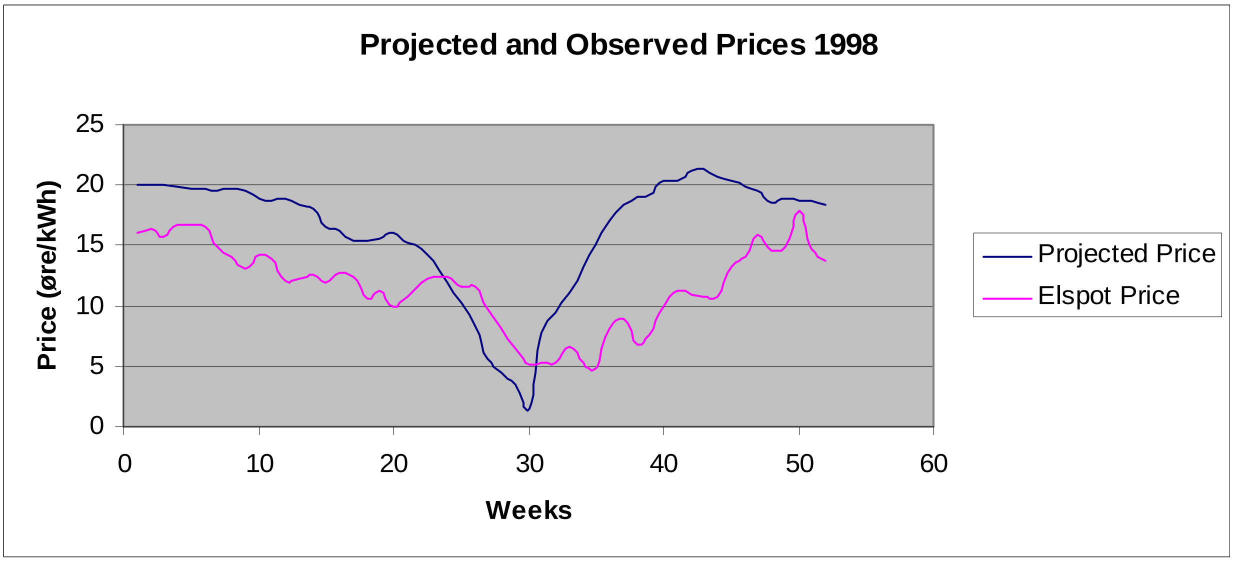

Figure 6.13 Projected and Observed Prices - 1998

Figure 6.13 shows a pretty good correlation between projected prices and the actual Elspot price for the same period. Although, the there certainly is a clear discrepancy between projected prices and observed prices, it is obvious that they have common tendencies. Obviously, a better fit between the two plots could have been obtained by tweaking the feedback factors and input values of the EMPS model. However, such precision tuning is not in itself interesting since the objective is to use the model to project prices for the dry years for which no market data are available for comparison. On the other hand, it is more interesting to see if there is a correlation of the tendencies in price development since such a correlation of tendencies probably are valid for all the simulated years.

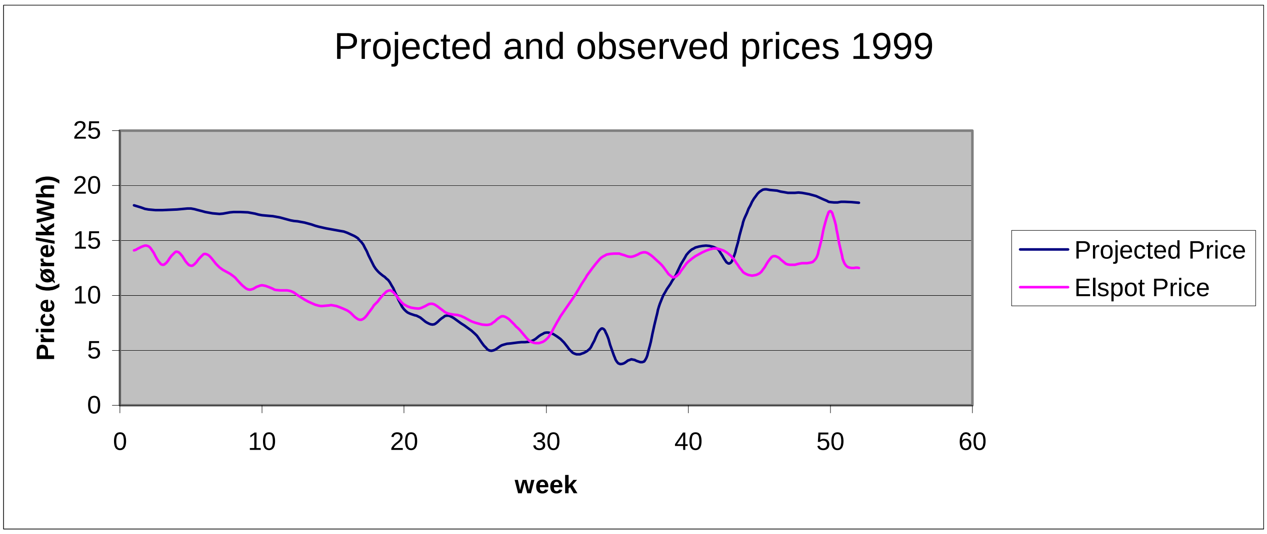

Figure 6.14 Projected and Observed Prices -1999

There common tendencies appear to be even stronger in Figure 6.14

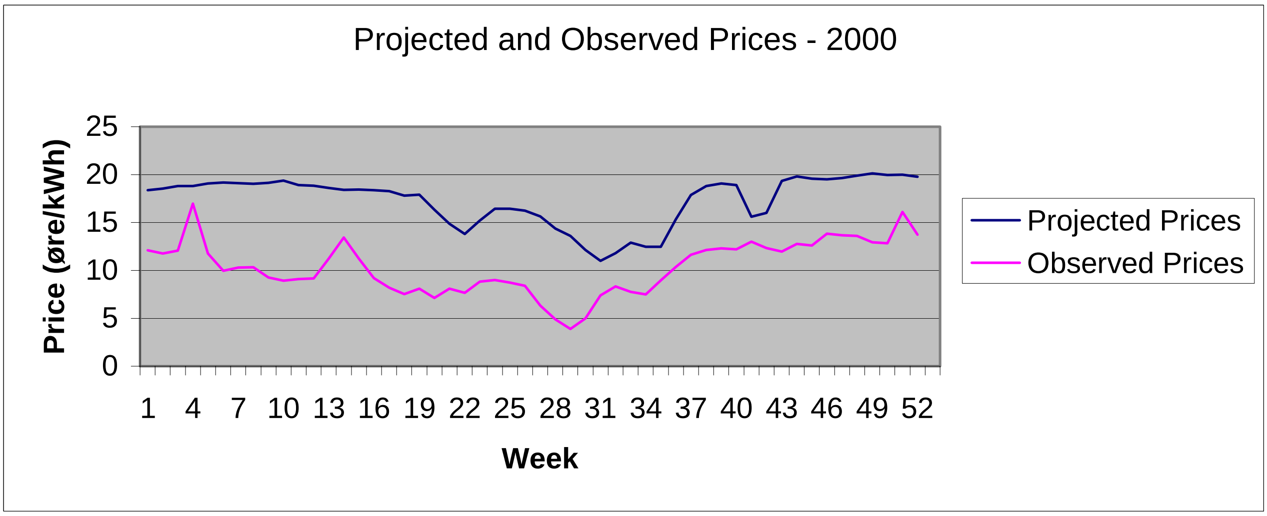

Figure 6.15 Projected and Observed Prices - 2000

Figure 6.15 also displays a corresponding price development. Here, the price developments almost match each other, except that the projected prices are shifted approximately 0.05 NOK above the observed prices.

Figure 6.13 to Figure 6.15 indicate a strong relationship between the price projected by the EMPS-model and an actual market price given the same inflow scenario

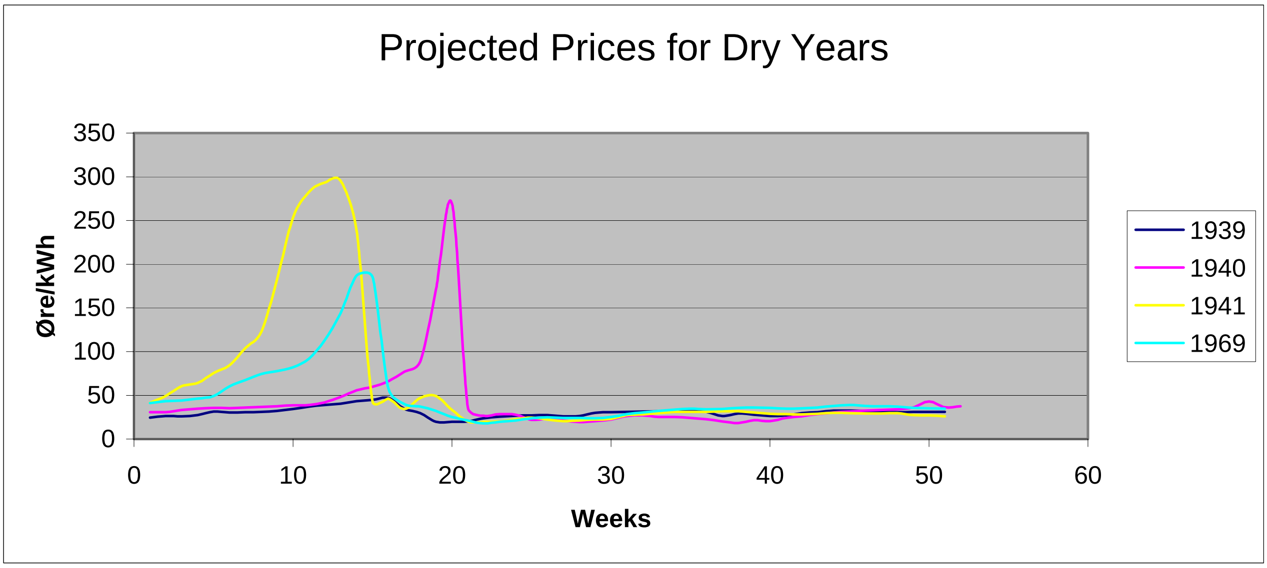

Figure 6.16 Projected Prices for dry years

Figure 6.16 show the simulation results for price development for the selection of dry years. With the exception of 1939, all the years appear to have been approaching empty reservoirs a few weeks before the spring flood. For 1940, it appears that winter lasted exceptionally long in what was otherwise also a gloomy year. It is nevertheless difficult to tell from this result whether the year was very dry or if the normal inflow profile only shifted a few weeks. However, with additional data from Figure 6.2, it appears that the result can be explained by a the combined effect of these factors.

As seen earlier, 1941 was an extremely dry year. Also, the carry-over effect from 1941 contributes to a comparatively long period of extremely high prices. A parallel to this situation would have occurred if 2003-2004 also had been a dry year.

7 Discussion

7.1 Power System and the Market Structure

The initial chapters describe the Nordic power system as well-understood, well-regulated and as a nearly perfect market. However, several threats loom as we enter the next few years. First, total production capacity is more or less completely stretched. Thus, in a normal year, Norway must import power in order to cover demand. The problems created by this energy shortfall are compounded by lacking transmission capacity some places in the grid, invariably creating bottlenecks. Practically all available sites for hydropower production in Norway have been developed, making it difficult to expand production capacity. Permission has been granted to build gas fired thermal power plants, but these remain controversial, and are still only in the planning stage. Alternative sources of energy, such as wind power and tidal power are increasingly being developed, but only on a small scale. The development of these energy sources look promising, but the current contribution of these energy sources to the total energy system remain small as the proverbial drop in the sea.

Also, as a result of many years of ample production capacity and cheap power, there are few curbs to consumption. Increasingly, various energy carriers have been replaced by electricity. Although it has never been a free good (except to some lucky residents in the major power-producing municipalities), it is certainly regarded as a staple good to the extent that throwing a light switch or turning up the heat is second nature to all of us (with the possible exception of very poor students). Consequently, dominant factors of demand are endogenous (e.g. temperature), while the price sensitivity of demand remains very low.

The combined effect of these characteristics of supply and demand is evident. In a normal year, with sufficient inflow to meet a relatively predictable demand, the power system and the market perform splendidly. However, should there be a surge in demand due to an extremely cold winter, or even more problematic, an unusual slump in inflow, capacity restrictions in production pose a large threat to the total power system and the market will react with extreme price spikes due to the low price sensitivity of demand. These effects were obvious in the winter of 2002-2003.

However, the chapter concentrating on elasticities argue that the price sensitivity of demand is somewhat more complicated than argued in the previous paragraph. It is shown that the clearing price not only displays the characteristics of an equilibrium moving up and down a demand curve. In fact, several mechanisms contribute to the continuous shifting and tilting of the demand curve resulting in a whole range of elasticity values. Berg and Bye [2003] show that short term demand elasticity changed from 4,1% to 5,4% from 2002 to 2003. Figure 5.1 demontrates how the options market may tilt the demand curve, and finally some calculations are provided in an attempt to quantify the change of elasticity with time.

7.2 Simulations and the EMPS-model

It is evident from the previous chapter that it is quite challenging to model price scenarios correctly. Indeed, it proved a challenge even to present credible results when modelling past scenarios where all the inputs and results were previously known. Obviously, even a perfect model will produce an emulation of history only if all the input data are correct, and in a comprehensive model such as the EMPS, a number of assumptions have to be made. Examples of such assumptions are:

	1.	All reservoirs were assigned an initial filling level of 70%
	2.	The division between firm power and flexible power remained constant.
	3.	Elasticity was set as a constant throughout the simulation period.

These are only examples of all the assumptions either consciously made or embedded in the EMPS-model.

As the results show, the effects on production of changing the elasticity of demand were small. Although the simulation results demonstrated the anticipated behaviour, the magnitudes of this effect were so small that they may be considered negligible. Counterintuitively, the effects were smaller in the dry years than in the wet years. However, on further inspection, this result is quite obvious as almost all production capacity is used to cover the demand defined as firm, leaving very little to flexible demand.

Price forecasting; which in effect was price “hindcasting” for previous inflow years, in order for the results to be compared to observed data; also proved to be an interesting venture. Although common trends in price development were quite obvious, actual prices diverged somewhat from forecasted prices. Nevertheless, the corresponding trends were clear in all three scenarios which were simulated

As described earlier, the EMPS-model allows for price-sensitive consumption. This consumption is modelled by defining a portion of the total demand as firm and the remainder as price sensitive. Then, a demand curve for this portion of demand is constructed either through stepwise inputs of quantity demanded at a given price or through the definition of a demand curve with a specific elasticity. Thus, demand is given as a variable, but relies on two factors which are given as constants at the beginning of each simulation.

In a normal year, this breakdown of demand serves its purpose well. However, in extreme years such as 02-03, there were several examples of firm power being resold by the supposed end-user as flexible power. This is an example of how the division of firm power and flexible power may change with time and more importantly, with price. Similarly, the introduction of two-way communication in the grid will allow certain predefined loads to be decoupled as the energy price reaches a certain threshold. Although, this technology is aimed at dealing with effect shortages in local grids, it should also have a certain impact on the total demand for energy.

Although the term market for energy appears to have matured, the exit of several speculators and market makers in the winter of 2002 form NordPool demonstrate the changes possible even in a well-established market. As shown by Chao and Wilson [2004], the options market has a direct effect upon the elasticities in the market, and a significant change in the quantity traded in the options market like the one experienced in 2003 should consequently contribute to that effect.

Simulation models remain the predominant tool for generation scheduling. The EMPS model is a pre-eminent example of such a model. It has been the reference model for hydro-scheduling for decades, and as it is continuously improved, it will maintain its position. However, as production capacity approaches its very maximum, threats of energy shortages like the one seen in the winter of 02-03 will become more frequent if production capacity is not expanded. These threats invariably result in characteristics in demand which only can be described as quite messy compared to the current predictable and controlled situation.

Although generation scheduling in a situation which resembles that of 02-03 is not the norm, chances are that similar situations will arise as long as the production capacity remain more or less at the current level.

8 Conclusion

The adequacy of the generation capacity in the Nordic market in the near future appears very uncertain. Uncertainty in the market will necessarily open for the possibility of an undesired reliving of the conditions of the winter of 2002-2003. A clear connection between high prices and increasing elasticities has been established in the literature, both on a theoretical level and through empirical studies of the Nordic power market. Also, it is shown that external factors such as the entry or exit of large players in the energy options market will have an impact on elasticity

From these observations, further work on the nature of elasticities in the Nordic power market may be warranted. It seems especially relevant to focus on how elasticities should be modelled for generation scheduling purposes. Development of models such as the EMPS model was initiated several decades ago when production capacity was ample and demand was more or less constant and predictable. Consequently, demand elasticities are modelled with static factors. It appears that a dynamic modelling of demand elasticity would provide a closer emulation of elasticities observed in a constantly changing market. Obviously, such a remodelling would require a lot of work and resources and it is far from certain that the results would justify the costs. In the end, this potential improvement will also be reduced to a question analogous to the one facing the generation scheduler every day: Namely maximising the value of a potential resource.

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Appendices

Appendix A Various Inputs to the EMPS model

Appendix B Various Outputs of the EMPS model