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Smart Grid - The Effect of Increased Demand Elasticity at the System Level

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Abstract

It is in this report given an analysis of the effect of utilizing load control in the Norwegian power system, which is one of the functions included in the Smart Grid consept. The analysis is performed by running simulations in the EMPS model. Effects are investigated in terms of increased socio-economic surplus in Norway and reduced prices during peak load periods in the area Østland.

Based on earlier studies it is assumed that it is possible to disconnect 600 MW of electric water heaters during peak load hours without reducing any comfort for customers. In this analysis, 600 MW is shifted from two peak load hours to a low load period, implying that 6 GWh/week (600 MW·2h/day·5 days/week) is shifted from peak load periods to low load periods.

Simulations using the existing model of the Nordic system show a net increase in socio-economic surplus of 20.208 MEUR per year by implementing a load shift. The average prices during the peak load periods are in this case reduced by 0.06 cent/kWh. In an extreme situation, a price reduction of 33.02 cent/kWh is observed. Including variation of wind power production in these simulations shows that the average price reductions are smaller and that the effect obtained in extreme situations is significantly smaller. This indicates that the effect of a load shift is somewhat smaller than what the results in the other simulations have shown.

An improved system model, where the functions quadratic losses and gradual consumption adaption are included, give that a load shift increases socio-economic surplus by 41.198 MEUR per year. The average price reduction are found to be about the same as obtained by the original model. The price reductions in extreme situations are however considerably lower.

Varying the exchange prices with the continental areas gives increased price differences between the price periods, which results in an even larger effect of load shift. The effect is especially large in a scenario where the prices in Germany and the Netherlands are very low during off-peak periods due to increased wind power production while the peak prices are high due to use of gas power plants instead of coal. An average peak price reduction of 0.07 cent/kWh and a price reduction of 10.48 cent/kWh during extreme situations are here found.

Some uncertainty is connected to the results due to difficulties when comparing results from different simulations, which occurs when the calibrating the models. However, the results still indicate the range of the values that a load shift provides, which is clearly positive.

Sammandrag

Denne rapporten gir en analyse av effekten bruk av laststyring, som er en av funksjonene i Smart Grid-konseptet, har på det norske kraftsystemet. Analysen er utført ved simuleringer i samkjøringsmodellen. Effekten er estimert ved å undersøke forandringen i samfunnsøkonomisk overskudd i Norge og forandring av elektrisitetspriser på Østlandet etter flyttet last.

Det er ut fra tidligere studier antatt at det uten å redusere kundenes komfort i topplasttimer er mulig å koble ut forbruk av varmtvannstanker som til sammen utgjør 600 MW. I denne analysen er 600 MW flyttet fra to typiske topplasttimer til en lavlastperiode. Dette gir at 6 GWh/uke (300 MW·2 h/dag· 5 dager/uke) flyttes mellom de nevnte periodene.

Simuleringer utført med den eksisterende modellen av det nordiske systemet viser et netto økt samfunnsøkonomisk overskudd på 20.208 MEUR per år ved å utføre lastflyttingen. De gjennomsnittlige prisene i topplasttimer er ved samme simulering redusert med 0.06 cent/kWh. I en ekstremsituasjon av høye priser er en prisreduksjon på 33.02 cent/kWh observert. Ved å i tillegg inkludere variasjon av vind innenfor ukene i disse simuleringene, får man lavere gjennomsnittlige prisreduksjoner i topplasttimene. Prisreduksjonene i ekstremetilfeller er også vesentlig lavere. Dette tyder på at verdiene funnet i de andre simuleringene i virkligheten er noe lavere enn resultatene viser.

En forbedret modell, hvor funksjonene kvadratiske tap og gradvis forbrukstilpasning er implementert gir at lastflytting øker det samfunnsøkonomiske overskuddet med 41.198 MEUR per år. Den gjennomsnittlige prisreduksjonen i topplasttimer er i denne simuleringen omtrent like stor som prisreduksjonen funnet ved den originale modellen. Prisreduksjonene i ekstremtilfeller er imidlertid mindre.

Forandring av utvekslingsprisene med kontinentområdene gir økte prisforskjeller mellom topplastperiodene og lavlastperiodene på Østlandet. Dette gir også større effekt av lastflytting. Effekten er spesielt stor i et scenario hvor off-peakprisene i Nederland og Tyskland er satt til null på grunn av økt vindproduksjon og peakprisene er satt høye for å modellere økt bruk av gasskraft i stedet for kull. En gjennomsnittlig prisreduksjon på 0.07 cent/kWh og en prisreduksjon på 10.48 cent/kWh i ekstremtilfeller ble funnet.

Usikkerheter er knyttet til resultatene på grunn av vanskligheter med sammenlikning av resultater ved kalibrering av modellen. Resultatene av analysen viser imidlertid en klar positiv verdi av å flytte last i det norske kraftsystemet.

Problem description

An important part of the Smart Grid concept is increased demand response, where one of the functions involved is remote control of consumption. It is expected that smart metering systems and new infrastructure for communication and data processing will make it economically beneficial and realistic to control customers' consumption according to the needs in the power system, signalized through price variations.

An analysis called 'The value of load shifting - An estimate for Norway using the EMPS model' was accomplished in 2006, estimating how controlling customers' electric water heaters will affect the Norwegian power system in terms of prices and socio-economic surplus. The analysis concluded that a number of weaknesses in the model gave unrealistic results. Some of these elements are now improved, and it is of interest to repeat the analysis.

The tasks are the following:

1. Model load shift as in the earlier analysis in the existing model of the Nordic system and analyze/document the results.
2. Model/make use of options that now are available in the EMPS model, especially long-term price elasticity, quadratic losses and improved wind modeling.
3. Analyze the effect of varying exchange prices with the continental areas.
4. Compare and discuss the results in 1. 2. and 3.

Assignment given: 03.03.2011

Preface

This master thesis is accomplished during the spring 2011 as a final part of my master degree at the Department of Electric Power Engineering at the Norwegian University of Science and Technology .

I would like to direct my gratitude to my supervisor Gerard Doorman for sharing his knowledge and giving me valuable advices throughout the work. It would be difficult to complete this thesis without the help from Stefan Jaehnert, who has answered many questions and helped me learning the EMPS model. I am also very grateful for the support from my fellow students and from my boyfriend Daniel Asp.

Trondheim, July 10

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Contents

List of Tables

*

List of Figures

*

Chapter 1

Introduction

The increasing need to ensure secure supply of electricity and at the same time reducing emissions of CO_2 requires large changes and development within the structure of the existing electricity grid. Climate goals have been agreed upon on an international level, as well as the Norwegian government has committed to emission reduction targets and goals to increase renewable energy production. Smart Grid is the notation of an electricity grid that is enabled to handle these future challenges.

Smart Grid involves utilization of advanced control systems and two-way communication which open for new opportunities for the customer to participate more actively in the power system. The installation of smart metering systems in every household in Norway includes the opportunity to control customers' consumption, which is signalized through price signals. This will result in a smoother load curve.

This study analyses the effect of disconnecting water heaters in Norwegian households, which in total constitutes that 600 MW of power consumption is moved from typical peak load hours to low load hours. In situations of power shortage, small reductions in demand can result in considerably reduced prices.

This report gives an analysis of the effect that load control provides on the Norwegian power system by running simulations in the EMPS model, which is a well suited model used in the Nordic power market for price forecasting, hydro scheduling and general market analyses. The effect will be considered in terms of difference in social surplus and electricity prices with and without the implementation of load control in the model. Several newly improved elements in the EMPS model is utilized in order to make the modeling as realistic as possible.

Chapter 2 provides background information about Smart Grid and demand elasticity and emphasizes the benefits of increased demand elasticity. Chapter 3 gives the necessary theory behind the EMPS model. In chapter 4, the method for the modeling of load shift and for the calculation of socio-economic surplus is explained. The input data to the system model is described in chapter 5, while in chapter 6, the description of the various simulations and the results of each simulation are given. Finally a discussion of the results and a conclusion is given in chapter 7 and 8.

Chapter 2

Background

2.1 Smart Grid

2.1.1 General description

The electricity grid of today is designed for one way energy flow, characterized by large, centralized power stations delivering power to the high voltage transmission network. The electricity is transported through the distribution network before ending up at more or less passive consumers.

The Smart Grid concept is all about utilizing two-way communication and control strategies to integrate all users connected to the power grid. Moreover, Smart Grid will facilitate for a proportion of the electricity generated by large conventional plants to be displaced by distributed generation, renewable energy sources, demand response, demand side management and energy storage [8]. Customers will be equipped with smart meters and be enabled to react on price signals, which will contribute to reduce peak load in the power system and even out the spot prices. Smart Grid will improve the potential of energy storage including batteries in electric vehicles as well as pumped hydro and possible compressed air energy storage (CAES). It will also enable renewable energy production from small distributed generation units such as solar panels at the consumer level. [9].

There is no official definition of Smart Grid, but several can be found in the literature. Based on these, a proper definition is proposed [9]:

"Smart Grid is an electricity network that utilizes two-way communication, control and sensing systems in order to ensure a cost efficient, reliable and sustainable power system with high levels of quality and security of supply."

2.1.2 Demand Response

The functions in Smart Grid that appear on the demand side are often associated with the term demand response. Demand response can be defined as the *"changes in electricity consumption by end users from their normal consumption patterns due to response to changes in electricity prices over time"* [10], i.e the same meaning which is entailed in the term change in demand elasticity. Demand response or demand elasticity is likely to be increased when customers are provided with the right technologies and given the right economic incentives. Demand response technology is represented by smart metering systems, which is described in the next chapter.

Economic incentives can be given by either offering the participants in a demand response program payments, or by implementing a time varying tariffs, where the price depends on the load in the power system over time. The customer will thus be awarded for load reduction during peak load hours.

2.2 Smart metering systems

2.2.1 Description and functions

The functionality of a smart metering system is to frequently meter, to communicate and to control electricity consumption of customers. The system may be divided into three system levels:

1. A customer level at households and industry locations with metering points and displays for electricity consumption
2. A communication system that transfers data between customer and central level
3. A central level at the network company

The system's main functions are to provide the opportunity to:

- *Reduce energy consumption* by letting customers be more aware of own energy consumption and electricity prices
- *Reduce power consumption* at peak load hours by letting customers react on real-time electricity prices
- *Remotely control customers' load* in order to reduce consumption peaks

The Norwegian Water Resources and Energy Directorate (NVE) has in their last hearing about the installation of a smart metering system stated that smart meters are to be installed for all customers in Norway within 1st of January 2017. [11]

2.2.2 Load Control

Remote load control is one of the functions included in a smart metering system. The concept entails that electricity supply to a large number of customers is turned off during peak periods. The automatic load disconnections are typically performed by a signal from the network company to a relay in each household's fuse box. The relay disconnects the heaters from the electricity until a new signal is sent for reconnection. This will result in a load shift from typical peak load hours to hours of lower load, which gives a smoother load curve in the power system. Participating in a load control program means for the customer to be willing to offer load reduction if they are compensated economically, often performed by offering time differentiating network tariffs. Several programs have been accomplished in the USA and in Australia, resulting in a reduced peak electricity consumption. [12] The effect on the load curve is illustrated in figure 2.2.1, where the stippled line indicates the original load curve and the black line indicates load curve with load control implemented.

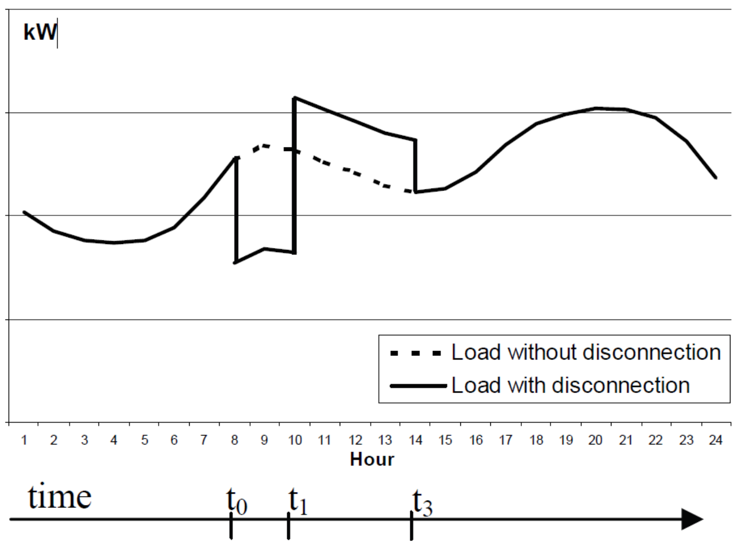

Figure 2.2.1: Effect on the load curve of a household during a day with and without disconnection of water heaters. [12]

As the figure shows, existing peaks of electricity consumption are cut, but there are certain "pay-back" effects during the low load hours; When loads are reconnected at the same time, it may result in new consumption peaks. This however depends on the level of consumption at both peak load hours and low load hours. The problem may be solved by cycling the disconnection/reconnection. [12]

A study [12] estimates that load control of water heaters in Norway result in load reduction per household of between 0.36 kWh/h and 0.58 kWh/h in the morning hours and 0.18 kWh/h up to 0.60 kWh/h in the evening. The reconnection gives payback effects of up to 0.28 kWh/h per household.

Water heaters constitute approximately 10% of the electricity consumption in Norwegian households. [12] The fact that hot water has the potential to be stored for long periods of time without significant heat loss, makes it well suited to heat water at one period of the day and to use this water at another period. Remote load control of water heaters has therefore been widely applied to reduce peak load. If all heaters have elements of 2 kW-rated capacity, the maximum theoretical load reduction potential is 2 kWh/h per heater. [12]

A pilot project accomplished in 2004 [13] found that physical disconnections together with time differentiating network tariffs and energy products give an average response of 500 W per customer. This gives 600 W of reduced production, taking transmission losses into account(20%). Assuming 2 million residential customers in Norway, and that 50% are using load control load, this gives an average reduction of 300 W per customer, resulting in potential of shifting 600 MW (300 W/customer * 2 000 000 customers) in the residential sector. If 600 MW is moved from two peak load hours to a low load period, it implies that 6 GWh (5 days x 2 hours) is moved per week. [13].

2.3 Demand Elasticity in Norway

The demand elasticity in the Nordic power system has traditionally been seen as very low in the long run and close to zero in the short run. This is explained by the structure of the power market. A crucial factor for how well the spot market is connected to the end user market is the way that customers are exposed to the electricity prices. If customers are exposed to real time variations in the spot marked and able to react to them, the demand elasticity will be increased.

Most of the contracts that are used within general demand in Norway are spot, variable or fixed price contracts. In the residential sector, the most common contract has traditionally been the variable price contract. The use of spot price contracts has however increased steadily since 2003, and reached a share of 55% by the first quarter of 2011.Less than 10% of the residential customers use a fixed price contract. [14] The choice of contract determines how fast a change that happens in the spot market will affect the end users. While using a spot price contract gives an immidiate effect, as the price of the contract changes according to the variations in the spot market, it takes longer until the variable price and fixed price contracts' prices are affected. These can be fixed for periods from weeks and up to years. [3]

The literature concludes that the end user market and spot market is in the

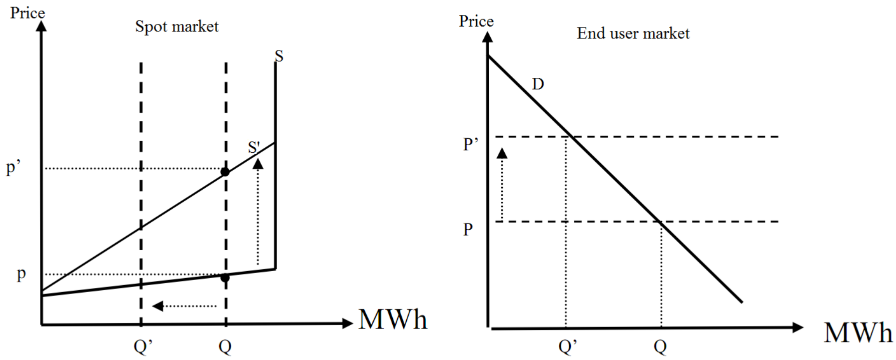

Figure 2.3.1: The connection between the spot market and the end user market. [3]

mid-term relatively well connected, while on short term, the two markets are almost distinct. [3] The connection between the spot market and the end user marked is illustrated in figure 2.3.1. The figure to the left shows the spot market. The customer is in the spot market represented by the electricity supplier, who submits inelastic bids in order to satisfy the customers' demand. The original demand curve is noted Q. The curve noted S is the supply curve when there is a satisfactory amount of water available in the reservoirs. With less energy available in the power system, the supply curve shifts to S' because the value of the water is increased. The demand level of Q results in the price p. When the supply curve shifts, the price increases to the price p'. The consumers will not have the incentives to reduce the consumption immediately because the price is not yet changed in the end user market. When the contract price is changed from P to P' in the end user market, as the figure to the right shows, the consumer will however reduce consumption from Q to Q'. This shows that there is some demand elasticity in the market, but that the connection between the end user market and the spot market is slow. [3]

A second element of importance within the discussion of demand elasticity is the procedures for consumption metering and settlement. Today, only customers consuming annually more than 100 000 kWh are being hourly metered. These are power intensive industrial consumers and some customers within service and industry. The power intensive industry often have contracts directly with supplier and are expected to have in-depth knowledge about the spot market, and thus be able to act strategically on the market. However, experience shows that the full potential of demand response is difficult to utilize because peak prices do not occur on a regular basis. [15] Within the service and industry sector, one could think that there would exist some price elasticity, as 80% in this sector are using spot price contracts. [14] The problem is however that the settlement for very few customers in this group is based on the hourly metered data, which means that an average price of the variations in the spot market through the settlement period is paid. [15]

The installation of a smart metering systems is expected to improve the connection between the spot market and the end user market as the customers will be exposed to real time prices and have incentives to react on them.

2.4 Benefits of increased demand elasticity

Increased demand elasticity implies a number of benefits for the customers, for the operation of the power market and the power system and for the environment. The central benefits in each category are listed below:

The customer:

The benefits of increased demand elasticity are experienced through lower electricity prices and possible incentive payments for participating in a demand response program.

The power market:

Firstly, the ability of market players to exercise market power is reduced through increased demand elasticity. It is estimated that during the California electricity crisis in 2000-2001, a reduction of demand by 5% could have resulted in a 50% price reduction. [10] This is due to the fact that the supply curve becomes very steep at the point when production reaches towards maximum capacity, as shown in the left illustration in figure 2.4.1. A more elastic demand curve would in this situation decrease the price significantly. Secondly, reduced and less consumption peaks will lead to more stable prices.

The power system:

Increased demand elasticity is likely to increase the system reliability by reduced risk of outages [10]. Moreover can increased demand elasticity result in avoided or deferred infrastructure costs, and cost reductions of expensive generation, imports and rationing. That is, increased demand elasticity may be of large importance in a situation of power shortage.

Figure 2.4.1 illustrates the effect of increased demand elasticity in a situation of power shortage. The supply curve becomes vertical when there are no possibilities to generate more power. This curve will shift to the left when there is even less

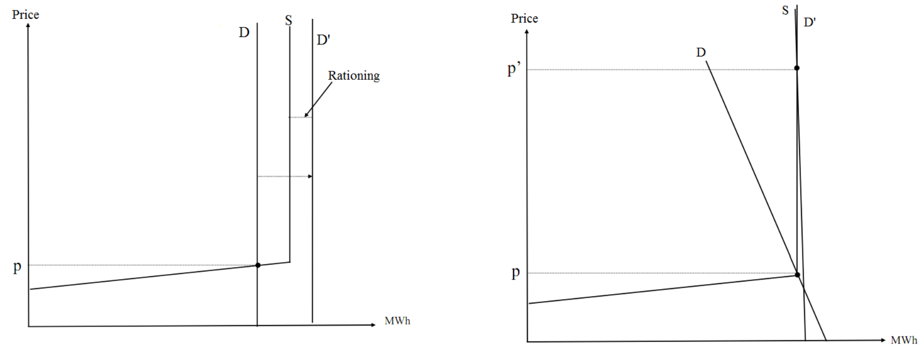

Figure 2.4.1: Effect of increased demand elasticity in a situation of power shortage. [3]

power available. In the left figure, the demand curve is totally inelastic. Market cross is obtained when the level of demand is at D, resulting in a price of p. If the level increases, and the curve shifts to D', there is not enough power available, and rationing will be necessary. In the figure to the right, the demand curve is more price elastic. The effect is that market cross is obtained, and as well as the price decreases considerably. [3]

Environmental benefits:

Environmental benefits are present in terms of deferred or avoided new electricity infrastructure such as transmission and distribution lines and avoided start-up of generation units of high greenhouse gas emissions.

Chapter 3

The EMPS model

In power systems where a large share of the production is hydro power, production scheduling is a complex task. Uncertainty regarding future inflow, demand, thermal generation and exchange with international power markets are elements that need to be considered in order to achieve optimal scheduling of such systems. The EMPS model is a stochastic model for optimization and simulation of system operation, that accounts of this kind of uncertainty. [6]

The EMPS model can be used to obtain results such as [6]:

- Hydro system operation (reservoirs, flows, generation, pumping)
- Thermal generation
- Power consumption, curtailment
- Exchange between areas
- Economic results
- Emission
- Incremental benefits of increasing the capacity of various facilities (hydro, thermal, transmission system

The EMPS model consists of two parts; one strategy part where the strategy for the use of reservoir water is determined, and a simulation part which simulates the system based on the incremental water values.

In the strategy part, the water values are calculated for aggregate reservoirs for a number of subsystems. The calculations are based on use of stochastic dynamic programming for each subsystem. The simulation is done for a number of historical inflow alternatives, typically 30-100 years. Optimal operational decisions for weekly hydro and thermal-based generation is calculated for each time step

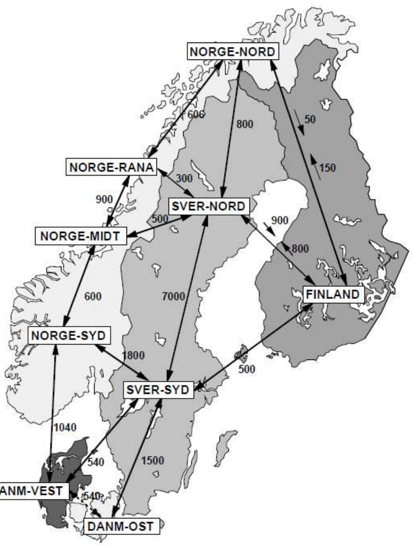

Figure 3.1.1: Example of a system model. Here the Nordic system is used as an example. [4]

via a market clearing process based on the water values of the subsystems. The processes are explained in details in sections 3.2 and 3.4.

A short description of the EMPS model is given in this chapter. Further details about the model may be found in [4], which has provided large parts of the contents to this chapter.

3.1 The system model

The EMPS model uses data for a defined system, consisting of several geographic areas. The interconnections between the areas are described by transmission capacity between the areas, losses and a transmission fee. An example of a system model is illustrated in figure 3.1.1. The system is in this case the Nordic countries, consisting of nine areas. Transmission capacities are here indicated as numbers on the connections between the areas.

Each area is described by the components hydro power, thermal power, wind power and demand. All areas do not have to contain all the elements. Figure 3.1.2 illustrates the description of an aggregate area with all its components. [4]

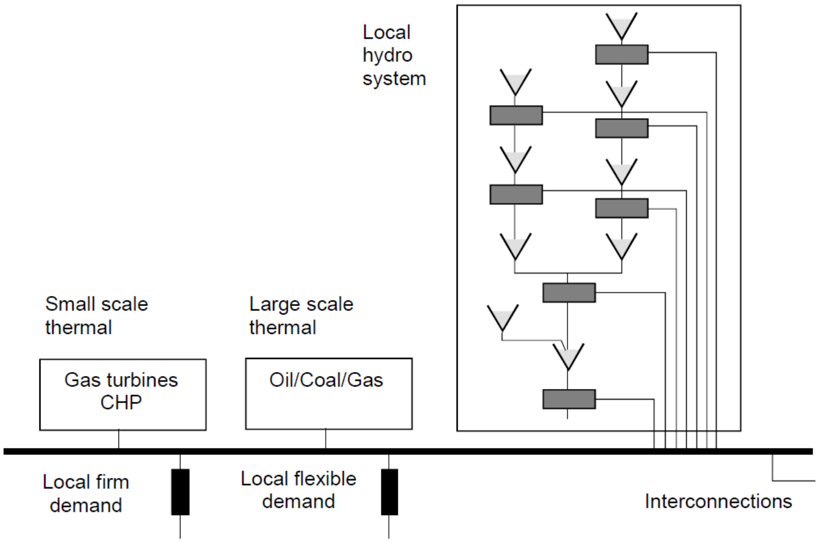

Figure 3.1.2: The aggregate area model, with the describing components supply and demand. [4]

3.1.1 Hydro power

Hydro power is described by standard hydro modules consisting of a reservoir with storable and non-storable inflow and a power station, as shown in figure 3.1.3. Different endpoints may be defined for plant discharge, bypass and spillage. Plant discharge and bypass may go to the reservoir downstream, while the spillage may be lost. [4]

Reservoir

A reservoir is always characterized by its volume, given in Mm^3. A piecewise linear curve can describe the relation between the volume and level for a real reservoir, where the level is given in meter above sea level (masl). [4]

Plant

The discharge capacity in m^3/s and the energy equivalent in kWh/m^3 must always be specified for a plant. The energy equivalent determines the amount of energy that is stored in each m^3 of water in the reservoir. This is calculated by formula 3.1.1. [4]

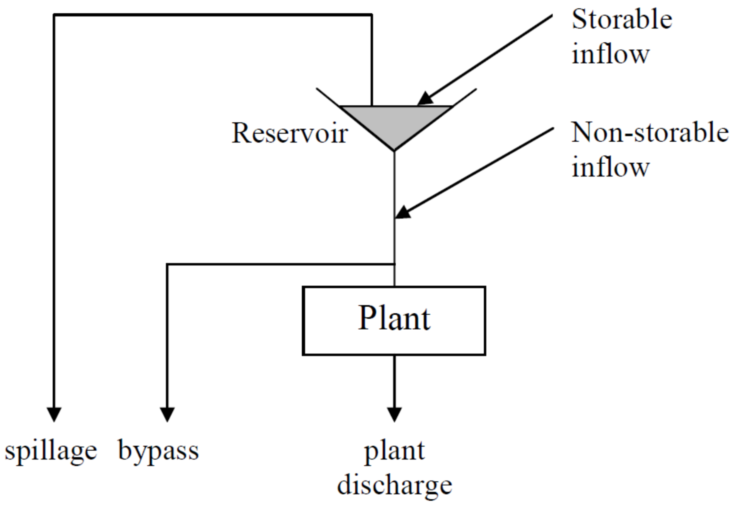

Figure 3.1.3: Standard hydro power module. [4]

$$e = \frac{1}{3,6 \cdot 10^6} \gamma g H \eta \tag{3.1.1}$$

where

γ = water density [kg/m^3]
g = gravity acceleration [m/s^2]
H = plant head [m]
η = plant efficiency

Inflow

Inflow is defined as storable and non-storable. Non-storable inflow must be used directly, and if this volume exceeds discharge capacity, the excess results in spillage. Inflow is specified as an average annual volume in Mm^3 for a certain time period and a reference record that describes the weekly and annual variation. High quality of these data are required in order to obtain realistic results in the EMPS model. [4]

Constraints

The modules have one or more of the following constraints [4]:

- Maximum and minimum reservoir level
- Maximum and minimum plant discharge
- Maximum and minimum bypass

Some constraints are set so that they must be satisfied at any cost, while some are met only if it does not lead to lost production.

Pumping

Pumping is modeled by a linear relation between the pump head and maximum pumping capacity and the capacity in MW used for pumping. Both reversible turbines and pumping turbines may be modeled. [4]

3.1.2 Thermal power

The thermal generation units are defined by expected available capacity and variable production costs, which depends on the fuel costs. The expected availability can be modeled using an expected incremental cost curve (EIC) for each time step. [4]

For some fossil fueled plants, special considerations has to be made regarding constrained inflow of fuel. These can be either be modeled as a hydro module, treating the gas contract as inflow and gas storage as a reservoir, or specified by a fixed energy volume available in the power system per week. [4]

3.1.3 Wind Power

Wind power production is given by historical data of wind speed for specified geographic areas, given as fixed hourly input to the model. The level of detail regarding geographical variation depends on the dataset for wind power production that is chosen to use.

The dataset Susplan is used in this study. It contains hourly wind data from the years 1947 - 2005, but uses the data that corresponds to the inflow years that are used in the simulation. This gives variation in wind production between years and between weeks. When simulations that include of start up costs of thermal production are run, variation in wind production within the weeks are included by aggregating the hourly data into the price periods defined in the model, so that an average of the data that belongs to the period is used. When simulations are run without start-up costs, the definition of the price periods are not taken into account, which means that an average production of the week is used.

3.1.4 Demand

Demand is modeled as firm demand and as price elastic demand.

Firm demand is defined by an annual quantity in GWh, an annual load profile and a within-week profile. The within-week profile is given by load factors that describes the load in certain price periods during the week. Firm demand can be made dependent on temperatures and on price, using a linear or exponential function to describe the relation between the price level and consumption quantity. [4]

Price elastic demand, also referred to as flexible demand, is defined by a weekly quantity in GWh and a disconnection price. When the marginal costs exceed this price level, the quantity is disconnected and not consumed. Normally, flexibility for boilers and some power intensive industry is specified in flexible demand. A new functionality in the model makes it possible to improve the distinction between short and long term price elasticity. The functionality is described in section 3.5. [4]

3.1.5 Power exchange

Power exchange between interconnected systems is modeled as spot exchange or contractually fixed exchange:

Optimal spot exchange is result of the market clearance process described in section 3.4, given by power costs, transmission capacity, losses and fees. When power exchange is modeled as fixed exchange, import and export is modeled as contracts that are used for certain time periods. These are specified by exchange volumes and prices.

3.2 Strategy part

In the strategy part, the expected marginal water values are computed as function of reservoir level and time, using stochastic dynamic programming. An aggregate model representation of the hydro system within each area, i.e an aggregate energy reservoir with an equivalent power plant and energy time series for storable and non-storable inflow is used to limit the computational burden. [6]

3.2.1 Energy inflow to aggregate system

For the aggregate model, the inflow has to be modeled in a special way in order to get realistic utilization of the reservoir. Considerations of overflow and spillage will be different from the modeling of inflow for the separate reservoirs. Storable and non-storable inflow is therefore calculated as shown below [4]:

Non-storable inflow =

	Generation due to non storable inflow to the power systems
+	Generation due to minimum discharge and/or bypass constraints
+	Generation necessary to avoid spillage
-	Energy used for pumping to avoid spillage

Storable inflow =

	Sum production (including time-of-use purchase contracts)
+	Increase (or - decrease) in reservoir volume
-	Energy used for pumping

3.2.2 Water values

The optimal operation of a hydro power system implies to minimize the operational costs of every week for the period of analysis. The total operational costs at a certain time equals all variable operational costs throughout the analysis period plus the costs of the change in reservoir level. This is also equal to the operational costs during the first week, plus the total operational costs, from time step $k+1$ until the end of the planning period. Equation (3.2.1) gives the mathematical description. The function $J(x,k)$ represents the value of the total expected operational costs from week k until the end of the planning period, where x indicates the reservoir level and k the week number. [4]

$$J(x,k) = S(x,N) + \sum_{i=k}^{N} L(x,u,i) = L(x,u,k) + J(x,k+1) \tag{3.2.1}$$

where

$S(x,N) =$ The costs if the change in reservoir, i.e the value of the start reservoir minus the value of the remaining content as a function of reservoir level x at the end of the period, time step N.
$L(x,u,i) =$ Operation dependent costs when going from period i to $i{+}1$. $L(x,u,i)$ includes costs of purchasing power, costs of own thermal power generation, costs of curtailment of firm power and income from spot power sales.
$u =$ Energy drawn from own reservoir to produce a certain quantity of power.

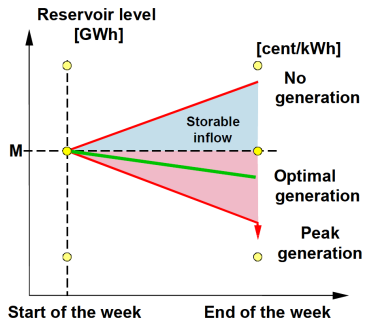

Figure 3.2.1: Optimal decision based on the water value. [4]

The value of u has an impact on the costs. The challenge is therefore to find the u that minimizes the costs, which means

$$min_u J = min_u L(x, u, k) + J(x, k + 1) \Rightarrow \frac{dJ}{du} = 0 \tag{3.2.2}$$

The solution of this gives that the condition for optimal strategy for period k is

$$\frac{\partial L}{\partial u_k} = \frac{\partial J}{\partial x_{k+1}} \tag{3.2.3}$$

where

$\frac{\partial L}{\partial u_k}$ = Marginal operation dependent costs associated with purchase, sale, curtailment
$\frac{\partial J}{\partial x_{k+1}}$ = Marginal total future dependent costs associated with the reservoir level, i.e the marginal water value at the time $k + 1$.

Optimal handling of hydro power for each week is achieved by using the water value as the resource cost of hydro power, i.e optimal use is when purchase and sales marginal costs equals the water value.

The optimal decision at the reservoir level m is illustrated in figure 3.2.1 for a given inflow, assuming that the water value is known by the end of the week.

This derivation assumes that inflow is known. To take uncertainty in inflow into account, this calculation must be run with a number of inflow scenarios. When stochastic inflow is used, the water value has to be calculated for each of the different inflow scenarios. Each inflow occurs with certain probability. The optimal water value is then given by equation (3.2.4).

$$\kappa_0 = \sum_{i=1}^{n} \kappa_i k_i \tag{3.2.4}$$

where
κ_i = the water values for the different inflow scenarios
k_i = the probability of the inflow scenario to occur
κ_0 = the resulting water value

3.3 Calibration

The water values that are calculated for one area must be modified so that exchange with other areas are taken into account. This is what is referred to as calibration of the model, and it is done manually. The objective is to minimize the total costs or maximize the social surplus. What mainly is considered in order to obtain this is reservoir handling and changes in total costs. [4]

Important signals for the reservoirs are:

- Distribution of the remaining reservoirs before spring culmination
- Emptying of large reservoirs with a high degree of regulation(size of reservoir/mean annual inflow) in dry years
- Filling up reservoirs in the autumn

Three calibration factors are being used. They are described one by one below, in the order of importance. [4]

Feedback factor - modification of firm demand

The quantity of firm demand is of large importance for the water values and simulated reservoir handling. The factor models the feedback of demand in other areas and therefore controls the volume of firm demand that is considered in the water value calculation. It therefore has an impact on the iso price curves and the curves describing the reservoir handling.

Form factor - annual distribution of demand

The form factor describes the annual distribution of demand over the year in one area compared to the interconnected system's annual distribution. A value of 1.0 gives a distribution equal to the interconnected system's. A higher value gives higher demand during the winter and lower during the summer, while a lower one gives the opposite.

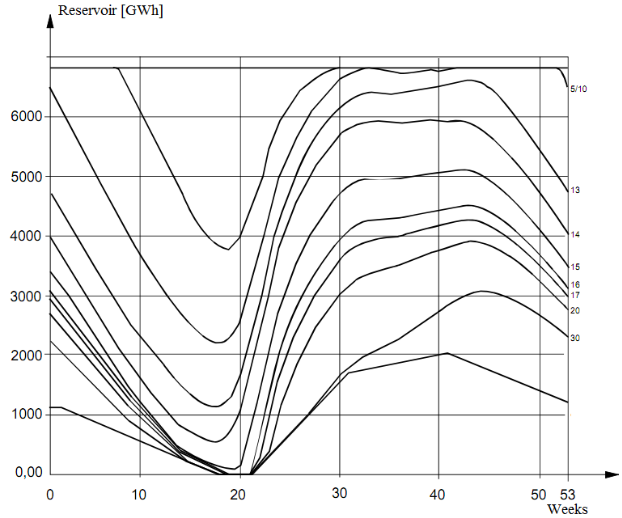

Figure 3.3.1: Iso price curves for given water values. [4]

Elasticity factor of price flexible demand

This factor has an impact on the quantity that is available at each price level of the demand curve, i.e the elasticity of the demand curve. Reducing the factor makes the demand curve steeper, which results in closer iso price curves and thereby the space for reservoir handling is reduced.

A method for automatic calibration is developed, that requires less from the user. The program seeks for the optimal socio-economic surplus by changing the calibration factors up and down by increasingly smaller step sizes. Finally a local optimum is found, which is seen as a satisfactory good result.

3.4 Simulation part

After calculating the water values in the strategy part, the simulation part is run in order to find the system operation state for the different inflow scenarios. The simulation is run in two stages: First the optimal decision on the aggregate area level using the computed water values is done, where costs, losses, capacities and constraints are taken into account. Then a detailed reservoir drawdown strategy is used to distribute the optimal total production between the available plants. It is here verified if the desired production is obtainable with all constraints associated. [4]

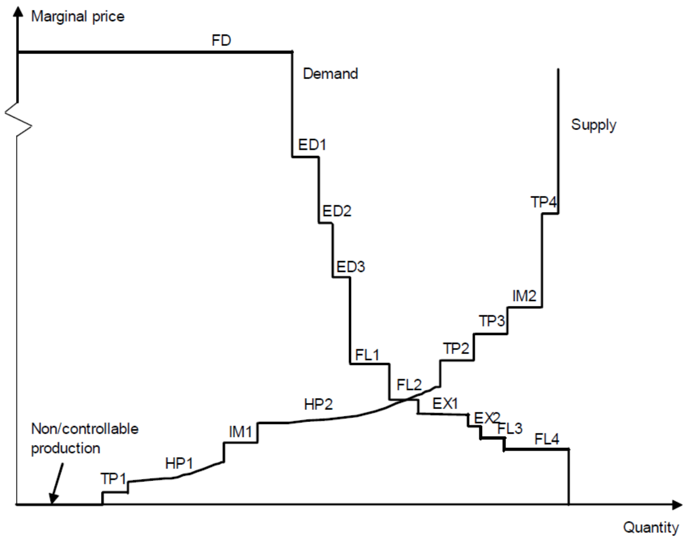

Figure 3.4.1: Market balance in the area optimization. [4]

Figure 3.4.1 shows the market clearance process in the area optimization. The incremental cost tables calculated for each aggregate regional hydro system are used to find weekly operational decisions on hydro and thermal power generation and consumption. The market clearance is decided by the supply and demand curves, where the intersection point gives the production and consumption volume. The supply curve is constructed so that the cheapest production is first used, and then price ranged. For the demand curve, the unit having highest disconnection prices is first used. FD indicates firm demand, which is given very high costs, i.e the rationing cost. Firm demand may also be described as elastic (cf. section 5.1), which here is given in discrete levels noted ED1-3. The categories FL1-4 represent flexible demand such as dual fuel boilers and power intensive industry. EX1-2 represents export. The supply curve is given by thermal power (TP1-4), import (IM1-2) and the water values function (HP1 and HP2). The optimal solution is found at the intersection of the supply and demand curves, which also gives the optimal hydro production in the aggregate model.

After the area optimization, the reservoir drawdown model is run separately for each area. The hydro generation is now distributed among available plants for each level of demand each week. If the production decided in the area optimization is not obtainable within the constrains at the detailed level, a new area optimization is run and modified. Figure 3.4.2 illustrates the steps of the simulation process.

The reservoir drawdown model uses two types of reservoirs [4]:

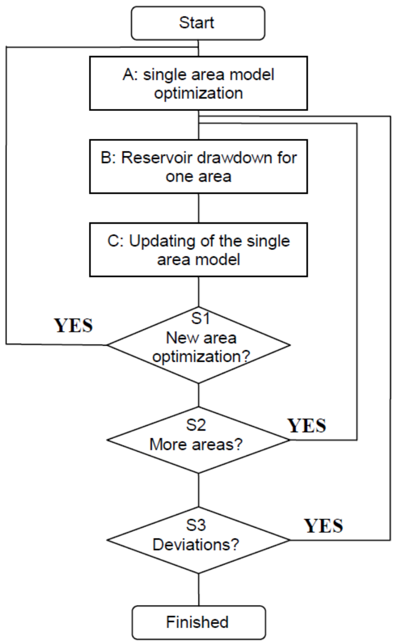

Figure 3.4.2: The steps of the simulation part in the EMPS model. [4]

- Buffer reservoirs: These are run according to guide curves, specifying the reservoir level as a function of the week number. They are having a low degree of regulation (ratio between reservoir number and annual inflow), and thus little impact on the results in the model.
- Regulation reservoirs, run according to a rule based strategy for allocation of stored water between the reservoirs.

The goal of the reservoir drawdown strategy is to produce a specified amount of energy with minimized expected future operational costs. This includes minimizing the risk of spillage during the filling season(late spring, summer and early fall) *and* avoiding loss of power capacity during the depletion season(late fall, winter, early spring). [6]

3.5 Improved modeling of flexible demand

A newly developed method in the EMPS model called *gradual adaption of consumption* provides the opportunity to model flexible demand in a more realistic manner. The method involves that instead of disconnecting consumption instantly when the market price exceeds disconnection price, the change in consumption adapts gradually to the market variations, where the consumption level depends on the general price level during the last weeks instead of only current spot price.

Two types of demand are normally modeled in the EMPS model as flexible; power intensive industry and electric boilers. Power intensive industry often has long term energy contracts with electricity supplier. They are however often interested in shutting down parts or the whole production in periods of long lasting high prices, in order sell contract volumes back to the market. This requires planning, and will not be performed by short term price peaks. The market for electric boilers is characterized by that the consumer is able to switch from electricity to other types of fuel in cases of high electricity prices, mainly oil. The consumption will be dependent on the relation between electricity prices and oil prices. [16] A second decisive element is the customers' contract type; a fixed price contract gives less incentives to adapt to short term price variations. The new method also allows to implement gradual adaption of firm demand. As this is not used in this report, the function is not further discussed.

3.5.1 Gradual adaption of flexible consumption

Using gradual adaption of flexible consumption means that flexible consumption will gradually adapt to the general price level; when the market prices stay high over time, the consumption will gradually reach towards minimum consumption.

When short term price variations occur, there will be less reduction of consumption. The effect is a more realistic distinction between short and long term price elasticity. [5]

Gradual adaption of flexible consumption can be implemented by two different methods; asymptotic and linear adaption. By lasting high prices, the flexible consumption will with these two methods respectively asymptoticly and linearly reach towards 0. Both are implemented by including an inertial parameter. [5]

For both methods, the total contract volume is divided into three parts:

Flexible capacity: The share of the total capacity that is disconnected in current week if the market price exceeds the disconnection price.
Inflexible in: The share of the total capacity that is consumed in current week no matter how high the price gets. This volume depends on last week's consumption volume.
Inflexible out: The share of the total capacity that is not consumed in current week no matter how low the price gets. This volume depends on last week's consumption volume.

The effect on the consumption curve of using the two methods and the original method on one contract of flexible demand is illustrated in figure 3.5.1. When the original method is used, the consumption is changed instantly when the price exceeds the disconnection price. This results in that the consumption level is nearly always at 0 or at maximum. This method is from now referred to as *instant adaption*. Comparing the two methods asymptotic and linear adaption, one can see that at low consumption levels, the consumption increases more rapidly when using asymptotic method than with the linear method. The consumption reduction is stronger for linear adaption than for asymptotic adaption. [5]

The consequence of specifying asymptotic or linear consumption adaption instead of instant consumption adaption depends on how large share of flexible demand that is included, the disconnection price and the parameters that are chosen in the implementation.

It is in this report chosen to use linear adaption because using asymptotic adaption makes the time until all flexible consumption is disconnected very long, as figure 3.5.1 shows. This method is described in detail in the next section.

3.5.2 Linear consumption adaption

Linear consumption adaption is implemented in the model by including an inertial parameter β_t, of which the value is specified by the user. The total capacity's three parts are for this method following [5]:

Flexible capacity is a constant share of the capacity in current week. If the

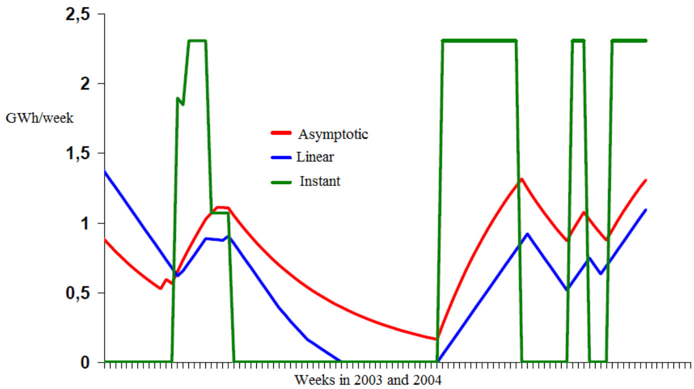

Figure 3.5.1: Flexible consumption using different methods for adaption. [5]

capacity is 15 GWh/week and the flexible share is a factor 3/15, the flexible capacity is 3 GWh/week.

Inflexible in is the demand of the current unit during last period minus half of the flexible capacity. If the unit consumed 10 GWh last week and the flexible capacity is 3 GWh/week, then 10 GWh/week - 3/2 GWh/week = 8.5 GWh/week is inflexible in.

Inflexible out is the total capacity in current week minus flexible capacity minus inflexible capacity in, i.e 15 - 3 - 8.5 = 3.5 GWh/week.

Mathematical description

Linear consumption adaption is given by the equations (3.5.1) - (3.5.4). [5]

$$y_t^{in} = y_{t-1} - (1 - \beta_t) \cdot y_t^{cap} \tag{3.5.1}$$

$$y_t^{flex} = 2(1 - \beta_t) \cdot y_t^{cap} \tag{3.5.2}$$

$$y_t^{out} = y_t^{cap} - y_t^{flex} - y_t^{in} \tag{3.5.3}$$

$$y_t = y_t^{in} + y_t^{flex} \, | p_t < c_t \tag{3.5.4}$$

where

t = week number
y_t^{cap} = the maximum capacity of the unit in week t
y_t^{in} = Inflexible in in week t
y_t^{out} = Inflexible out in week t
y_t^{flex} = Flexible capacity
y_t = Consumption in week t
c_t = Disconnection price of flexible consumption in week t
p_t = Electricity market price in week t
β_t = Inertial parameter for linear adaption in week t

If (3.5.1) gives that $y_t^{in} < 0$, then (3.5.1) is replaced by (3.5.5).

$$y_t^{in} = 0 \tag{3.5.5}$$

In addition, flexible capacity must be adjusted when the limit of maximum consumption is reached. If $y_t^{in} + y_t^{flex} > y_t^{cap}$, then 3.5.2 is replaced by (3.5.6)

$$y_t^{flex} = y_t^{kap} - y_t^{in} \tag{3.5.6}$$

3.5.3 Expected spot price

The gradual adaption can be based on the electricity price and disconnection price in current week, but may also be based on historical weekly prices or on an average disconnection price for a future time period.

Adaptive expectation of prices

Adaptive expectation of prices indicates that the price expectations are decided by historic data of prices, as in (3.5.7):

$$E[p_\tau] = \sum_{t \geq s \in S} a_s p_s \forall \tau > t \tag{3.5.7}$$

where S is a set of historic weeks, for instance last 4 weeks, a_s is the relative weight of the price in a given historic week (including current week). [5]

Today's electricity price may often be a good estimate of future price for some weeks ahead. It is possible to implement current week's spot price as expected spot prices by setting $S = t$ in (3.5.7). In order to reduce short term price

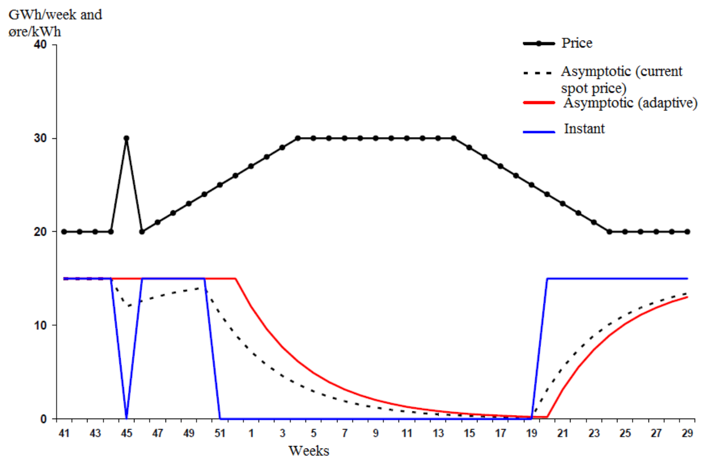

Figure 3.5.2: Load profile using asymptotic adaption with adaptive expectations and current spot price expectations and instant adaption. [5]

variations' effect on the expected prices, one may choose a more general type of adaptive expectations than by this specification. [5]

The difference between using instant adaption, gradual adaption with expectation of current spot prices and gradual adaption with adaptive expectation of spot prices is shown in figure 3.5.2. Expected price is set as average prices of last month. The figure shows that short term peaks in price do not affect consumption when using adaptive expectations, and that there are larger delays by lasting high prices when using adaptive expectations. [5]

3.6 Implementation of quadratic losses

In the original system model, the interconnection losses between areas are calculated using a linear approximation. The losses in a transmission line are in reality quadratic in relation to transmitted energy. A more realistic method representation of interconnection losses is developed, where quadratic calculation is used. When linear approximation is used, it is insignificant to consider the time of when energy is transmitted on a line. Using quadratic losses makes it more expensive to transmit at the times when the capacity of the line is fully utilized. Thus will the flexibility of the lines be reduced. [17]

When using quadratic losses, the capacity of the line is divided into a number of segments. The length of the segment indicates the transmission capacity of the given segment. The loss coefficient is for each calculated as given in equation (3.6.1):

$$Loss_i = (\frac{P_i}{P_{Max}})^2 \cdot Loss_{Max} \tag{3.6.1}$$

where
$Loss_i$ = the loss coefficient of line segment i
$Loss_{Max}$ = the maximum loss coefficient of the line
P_i = aggregated transmission capacity up till line segment i
P_{Max} = maximum transmission capacity

Chapter 4

Method

4.1 Basis

The effect of shifting load from the peak load periods to the low load periods on the Norwegian power system is analyzed using the EMPS model. The effect is analyzed in terms of:

- Change in social surplus
- Reduced average electricity prices during peak load hours and increased average electricity prices during low load hours
- Reduced prices in extreme situations, i.e when very high prices occur

The effect on price changes is limited to analyze the prices in the South-East part of Norway, in the model noted as the area Østland,

The basis for this study is Gerard Doorman and Ove Wolfgang's (SINTEF Energy Research) report "The value of Load Shifting - An estimate using the EMPS model" [6]. The work did not result in the expected positive result, and it was concluded that several elements in the model could be improved. In this report, the same simulation with the existing model of the Nordic system is first run before following new elements are implemented in the model:

- Improved wind modeling
- Improved modeling of flexible demand
- Quadratic losses

Finally it has been looked at the impact of varying the exchange prices with the Netherlands and Germany, which are modeled by financial contracts.

The simulations were run in several turns, numbered as simulation A - E. Note that two cases of the model are defined: a reference case and a load shift case. The reference case is defined as the model where flexible demand is modeled as of today. The load shift case is defined as the model where a load shift of 600 MW is implemented between the peak load periods Norwegian High and Swedish High and the low load period Low Day. These two cases are independent of the options that are implemented in each of the simulations and are used throughout the report for several simulations, to compare the results from the simulations with varying functions.

4.2 Model description

The system model is obtained by SINTEF Energy Research [18], which includes data for inflow of the years 1951-1990, hydro power plants, thermal power plants, wind production, demand and interconnection capacities. The original model contained all areas in Northern Europe, as illustrated in figure 4.2.1. In this study, the continental areas were disconnected so that the model only contains information about the Nordic countries. The interconnections to the Netherlands, Germany and Poland are instead described by financial contracts. All updated input data are described in chapter 5.

Calibration of the model is performed by using a script that runs through simulations with the changing calibration factors iteratively, seeking to find the highest value of social surplus.

4.3 Value of increased demand elasticity using social surplus as a measure

The general effect of demand response on social surplus explained as in [6] is given below. Figure 4.3.1 illustrates the effect.

Socio-economic surplus is defined as the area between the demand curve and the supply curve, i.e consumer surplus, which is the area below the demand curve down to the price, *plus* producer surplus, being the area above the supply curve up to the price. When demand response is implemented, the demand curve becomes more price elastic. This gives an apparent reduction in consumer surplus.

The two demand curves 'less elastic demand' and 'more elastic demand' indicates respectively the original demand curve and the demand curve where demand response is implemented and has resulted in more price elastic behavior. VOLL is the point where demand is totally inelastic, set at a very high price level. The demand curves is somewhat elastic down to a certain point, where the demand will not increase more, even at a price of zero.

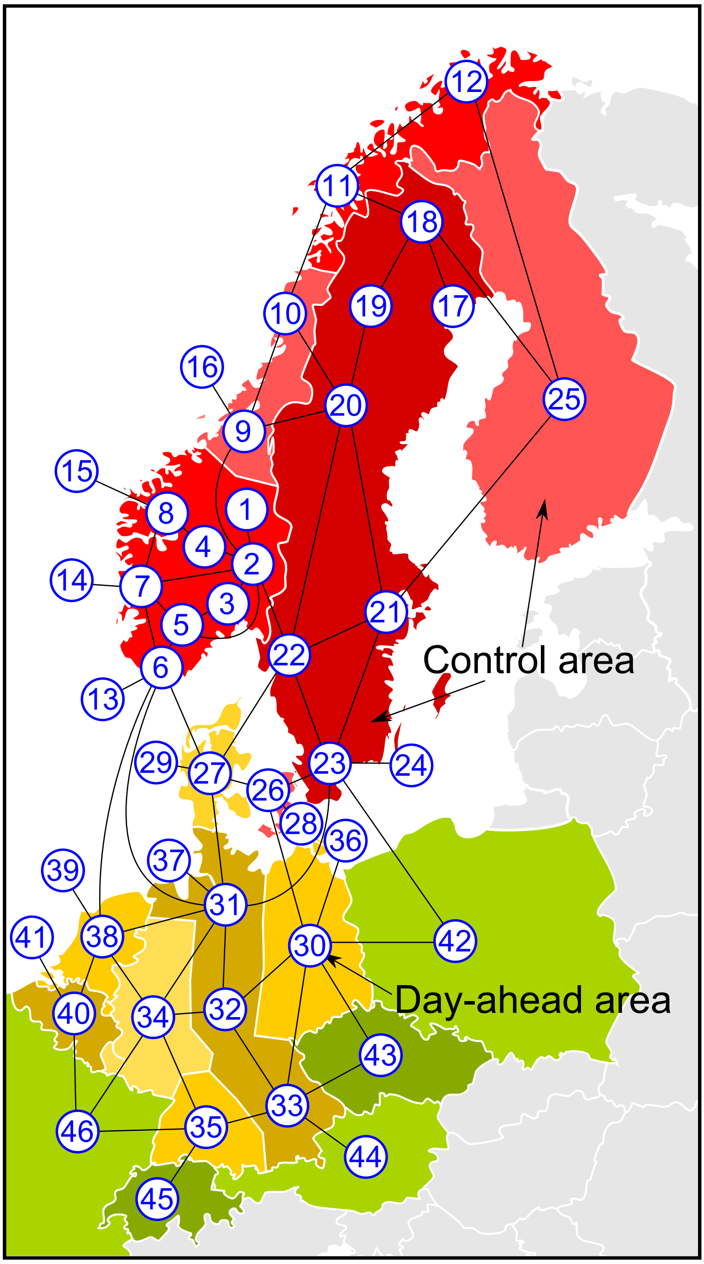

Figure 4.2.1: The system model, with Europe attached.

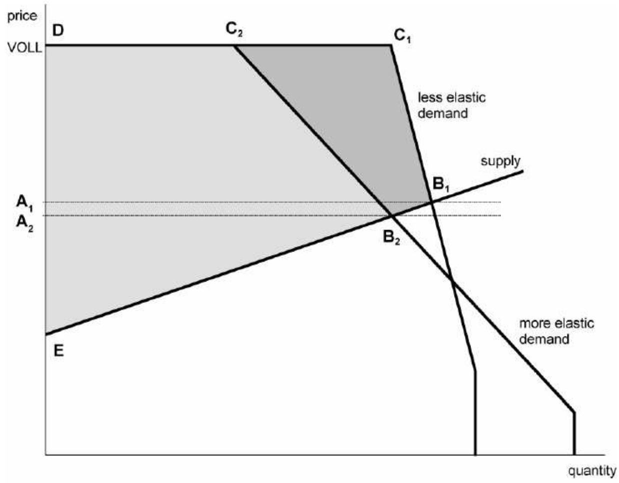

Figure 4.3.1: Change in social surplus due to increased demand elasticity. [6]

With demand response implemented, social surplus has decreased from the area B_1C_1DE to the area B_2C_2DE. As the figure shows, the apparent reduction in social surplus is mainly caused by the reduction in consumer surplus from $A_1B_1C_1D$ to $A_2B_2C_2D$.

The apparent reduction in consumer surplus is however somewhat misleading. Firstly, the increased elasticity may already have been existent among the customers, but not visible because of the market structure where customers are not exposed to real time prices. When this is changed, the demand elasticity is revealed. This phenomenon must be compensated for in a calculation of difference in social surplus. [6]

The increased demand elasticity gives reduced prices, which increases consumer surplus. With a very inelastic supply curve, the effect of this may be larger than the apparent reduction in consumer surplus. [6]

By the method that is used to implement load shift in this analysis, the demand curve will not change to become more price elastic, as in figure 4.3.1, the demand and supply curves are simply shifted by a certain volume for each of the price periods. The illustration still shows the main effect that demand response has on social surplus. Another important note is that the shift in the demand curve may lead to a reduction in consumer surplus in one period, while it leads to increased consumer surplus in the period that load is shifted to. [6]

A second measure that is used in this report to see the effect of load shift is the changes in electricity prices in Østland. Lower prices do not always coincide with increased social surplus, although it is often the case. Still, lower prices as a result of that more customers react to prices and reduce their demand, is an evidence of a more efficient market, which probably gives less need for new investments in generation capacity and transmission lines. [6]

4.4 Implementation of load shift

The load shift is based on the potential of disconnecting electric water heaters in Norwegian household described in 2.2.2, which indicated that 600 MW of electric water heaters can be disconnected during the peak load hours in Norway. This gives that 6 GWh/week (600 MW*2h*5days/week) can be shifted from peak load hours to low load hours.

The load shift is in the model distributed among the areas according to their share of firm electricity demand, so that for instance an area having 30% of total firm demand in Norway is allocated 30% of the total load shift, i.e 30%*6 GWh = 2 GWh. The exact numbers of the areas' consumption shares and how the load is distributed can be found in appendix A.1.

It is not obvious how to implement the load shift in the EMPS model. Fixed demand is described by a weekly load profile, given by relative factors. The variations within the year is given by an annual profile. A change in the weekly profile for allocation of 6 GWh from peak load hours to low load hours would only give relative change and not an absolute change. A second option is to implement the load shift as units of flexible demand. Removing exactly 6 GWh from the peak load hours is however difficult, as one unit is described by a volume and a disconnection price. [6]

The load shift is therefore implemented as a new generating unit during the peak load hours Norwegian High and Swedish High and a new consuming unit during the low load hours Low Day. The generating unit is connected at a price of zero, i.e it will always be producing. The consumption unit is given a very high disconnection price, so that it is always consuming, no matter how high the market price is. This means that instead of shifting the demand curve during the peak load hours, the supply curve is shifted by the same quantity in the opposite direction, which gives the same effect on the prices. It is important to note that this method requires an adjustment of estimated social surplus in the load shift case. The calculation of the adjustment is described in detail in appendix A.2, and is calculated according to equation (4.4.1):

$$A = \Delta V_{LS} \cdot t \cdot p_{LS} \tag{4.4.1}$$

where

A = Adjustment of socio-economic surplus in the load shift case, given in MEUR
ΔV_{LS} = the volume of the load shift, given in MWh/week

t = the number of weeks that load shift is implemented during the analysis period
p_{LS} = disconnection price of the consumption unit that is implemented during the low load periods

The adjustment A must be subtracted from the calculated socio-economic surplus that is calculated in the load shift case.

Chapter 5

Input Data

This chapter describes the data that are changed or added to the system model for this study.

5.1 Weekly profile of firm demand

The weekly profile can be divided into up to 12 price periods. It is here chosen to use 7 periods, as shown in table 5.1.1.

Table 5.1.1: Price periods used in the model

Number	Name of period	Hours per week
1	NH (Norwegian High)	5
2	SH (Swedish High)	5
3	HD (High Day)	28
4	LD (Low Day)	37
5	Night	45
6	WD (Weekend Day)	30
7	WN (Weekend Night)	18

It was seen as important to use a realistic weekly profile in this project, as the purpose was to see the effect of changed load during certain hours. The system model originally used a division of price periods where the period of highest demand had a duration of 30 hours per week. This is not identifying the peak that occurs in the power system satisfactory well, and it is likely to give little effect of load shifting. New price periods were therefore defined as described below.

5.1.1 Norway and Sweden

New relative hourly values of demand for Norway and Sweden were calculated by using data of hourly consumption for the years 2003-2007, provided by NordPool. The peaks are highest during the winter, and it is most interesting to see the effect of load shifting for this period. It is therefore chosen to base the weekly profile on the demand data of the winter weeks, i. e. week 49 to week 9.

The hourly consumption data included consumption from all sectors, that is, general demand, power intensive industry, boilers and pumping. General demand in Norway was calculated by subtracting consumption in power intensive industry and electric boilers from the total consumption. Hourly registrations for each sector were not available. Energy consumption in power intensive industry is however relatively constant over the year, except for a small decline during the summer. This variation is not taken into account, and hourly consumption of power intensive industry and boilers was therefore found by dividing yearly consumption by number of hours in the year. Energy for pumping is assumed to occur only in the weeks 19-44 and is thus not subtracted from the consumption data.

The dataset in the EMPS model does not contain information about Swedish flexible demand, all Swedish demand is included as general demand. The weekly profile is therefore based on data of total consumption in Sweden.

Relative hourly values were calculated by first finding the average value of hourly demand during the week, i.e 168 values. Hourly general demand is then normalised so that the annual average is 1. Corresponding values relative to this are called Per Unit values or relative values. This gives a relative demand profile throughout the week. As these relative values are estimated only for the winter weeks, they are high relative to average consumption; all above 1. To get more intuitive values, the PU values are again normalised so that the average is 1 (i.e the average of hourly consumption over the winter weeks). The resulting within week averages are illustrated in figure 5.1.1.

By studying the variations given in figure 5.1.1, new price periods were found. The highest peaks in Norway (from which load is preferred to be moved) were identified as hour 9 every working day, i.e hour 9, 33, 57, 81 and 105, and constitutes the period 'Norwegian High'(NH) 106 and 107 were also found to be peak hours, but for practical reasons which will be explained below, these were placed in the 'High Day' period. The afternoon peak occurs in Norway in hour 18 on every working day except Friday, i.e hour 18, 42, 66 and 90. Friday afternoon has lower consumption and therefore no peak. The peaks in Sweden are occurring at the same time as the afternoon peaks in Norway, giving this period the name 'Swedish High'(SH).

A load shift will be implemented from two peak load hours every day, that is NH and SH. This means that in order to implement load shift in the model,

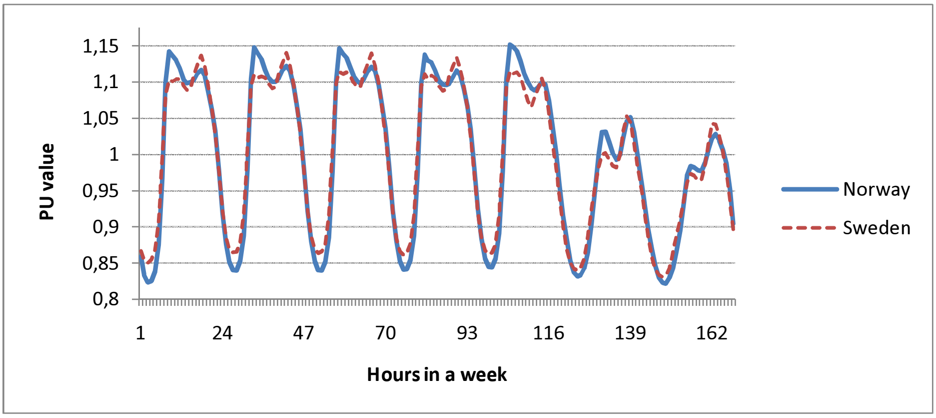

Figure 5.1.1: Average relative values for Norway and Sweden within a week. Based on values from the years 2003-2007.

it is convenient that these periods include the same hour of the day every day. Therefore, hour 106 and 107 are not included in the NH period and hour 114 is included in the SH period, although it is not seen as a peak load hour.

The remaining hours are classified into the periods 'High Day'(HD), 'Low Day'(LD), 'Night'(N), 'Weekend Day'(WD) and 'Weekend Night'(WN), distributed according to their PU values. The resulting PU values for the periods through the average of the PU values in that period. Table 5.1.2 gives an overview of the period names and the hours they include with belonging PU values.

The duration curves for the electric load in Norway and Sweden during the different price periods are illustrated in figure 5.1.2. The curve starts from the right with the period of highest relative load and continues with decreasing relative loads. As also can be seen by the the values in table 5.1.2, the order of the price periods is not the same for the two countries. This means that for Norway, the curve starts at NH, then comes HD, SH, LD, WD, N and finally WN. Sweden starts at SH, NH is second highest, then HD, LD, WD, N and WN.

As the figure shows, Norway has a sharper load profile than Sweden; the peak is higher and the bottom value is lower. This is not expected, as Norway uses more electricity for heating, which should give a more flat curve. The reason why this is not the case is probably that industrial consumption and boilers are not included for Norway while it is for Sweden. This gives a sharper profile for Norway.

Table 5.1.2: Price periods with belonging PU values

Period	Hours included in the period	PU value Norway	PU value Sweden	Number of hours
NH	9, 33, 57, 81, 105	1.146	1.111	5
SH	18, 42, 66, 90, 114	1.115	1.131	5
HD	10,11,12,13,17,19, 34,35,36, 37,41,43,58,59,60,61,65,67,82, 83,84,85,89,91,108,109,106,107	1.121	1.110	28
LD	8,14,15,16,20,21,22,32,38,39,40, 44,45,46,56,62,63,64,68,69,70, 80,86,87,88,92,93,94,104,110, 111,112,116,117,118, 113,115	1.083	1.077	37
N	1,2,3,4,5,6,7,23,24,25,26,27,28, 29,30,31,47,48,49,50,51,52,53, 54,55,71,72,73,74,75,76,77,78, 79, 95,96,97,98,99,100,101,102, 103, 167,168	0.890	0.905	45
WD	128,129,130,131,132,133,134, 135,136,137,138,139,140, 141,142,152,153,154,155,156, 157,158,159,160,161,162,163, 164,165,166	0.990	0.986	30
WN	119,120,121,122,123,124,125, 126,127,143,144,145,146,147, 148,149,150,151	0.862	0.864	18

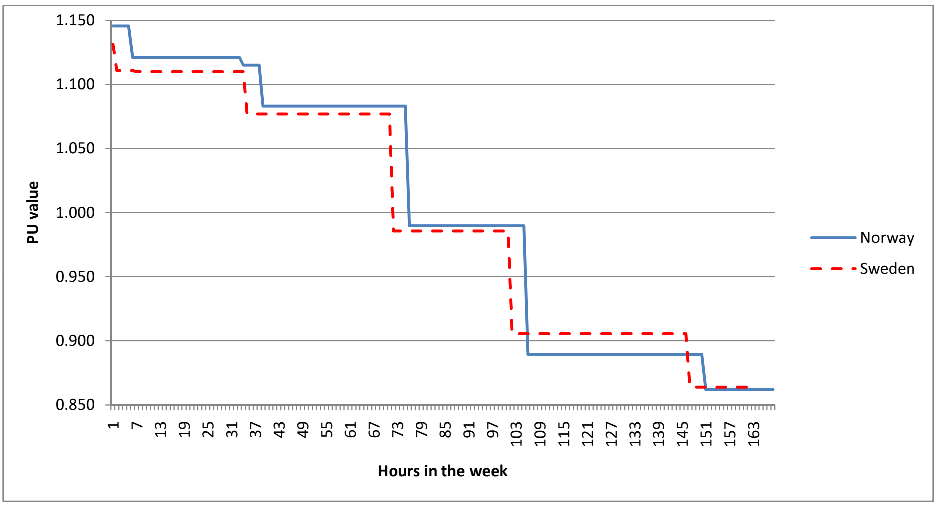

Figure 5.1.2: Duration curves for electricity consumption during the week in Norway and Sweden, sorted from the high load periods to the low load periods.

Denmark and Finland

For Finland and Denmark, the relative values that were already included in the dataset of the system model were used.

Table 5.1.3: Relative values for Denmark and Finland during the different price periods

	Denmark	Finland
NH	1,249	1,133
SH	1,249	1,133
HD	1,162	1,072
LD	1,079	1,047
Night	0,782	0,865
WD	0,925	0,973
WN	0,719	0,849

Because the price periods were changed for Norway and Sweden, some modifications had to be made so that the PU values for Denmark and Finland would fit into the model as well. The PU values used are given in 5.1.3. The highest values were put in NH and SH, the former 'Høy Kveld' were set in HD, 'Lav Dag' to LD, 'Natt' to N, 'Helg' to WD, and the average of 'Natt Lørdag' and 'Natt Søndag' was set as WN.

The duration curve for Finland and Denmark is illustrated in figure 5.1.3

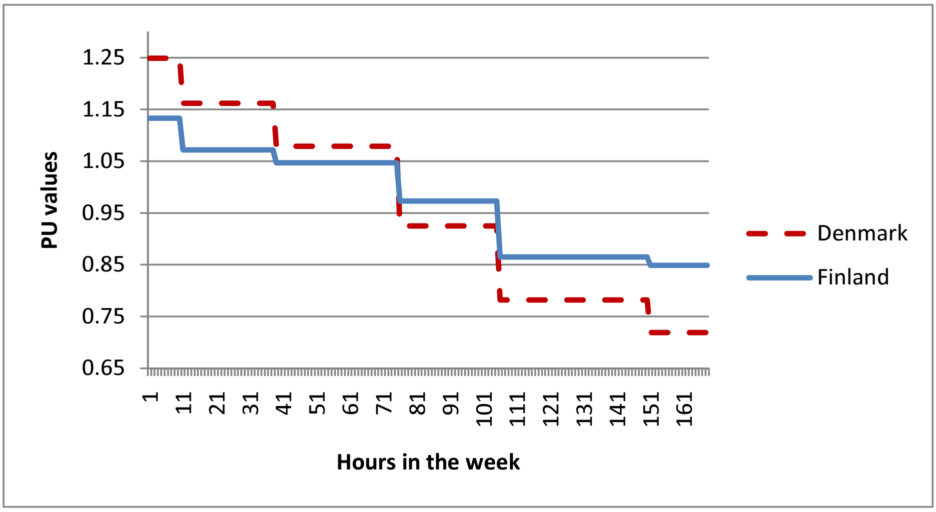

Figure 5.1.3: Duration curves for electricity consumption during a week in Finland and Denmark.

5.2 Reserves

There must always be reserves available in the power system, mainly due to uncertainty and short term variations in demand and generation and transmission system outages. A certain amount of generation reserves is responsible for this, which means that they produce below their maximum value. This is here modeled by reducing maximum capacity of power plants in Norway, Sweden, Denmark and Finland. The volume that is reduced of power plants in the different countries is defined in table 5.2.1. These volumes are the same as used in [6], which are based on considerations of the required primary and secondary reserves in the Nordic power system. The volumes of capacity reduction were set somewhat lower than the actual requirement, because it would be too pessimistic to remove all this, meaning that the required reserve capacity never serves demand, even in extreme situations.

Table 5.2.1: Modeled reserves

	Capacity	Type
Norway	1100 MW	Hydro power
Sweden	1200 MW	Oil power plants
East Denmark	415 MW	Thermal power
West Denmark	310 MW	Thermal power
Finland	840 MW	Thermal power

Norway

In Norway, the reserves were modeled by reducing maximum capacities of the largest hydro power modules in the areas that contain high hydro power production. It is important that the reduced capacities is distributed among different reservoirs, as too large reduction could lead to too low water values and in worst case spillage.

Sweden

In Sweden, about 1200 MW of generation were removed by reducing capacity from oil power plants having high marginal costs. Capacities were reduced by about 950 MW in south, 140 MW in east, 100 MW in the western part.

Denmark and Finland

Thermal capacity of high marginal cost was removed in Denmark and Finland, together constituting the amount given in 5.2.1. More details about the reduced maximum capacities in Norway, Sweden, Denmark and Finland are given in appendix B.1.

5.3 Modeling the continental areas

The import from and export to the continental areas are modeled by financial contracts. These are given by specified prices and volumes for three defined time periods based on the price periods given in table 5.1.1: Off-peak, base and peak. Off-peak includes the price periods 5 and 7, base includes 4 and 6, while the peak contract is used in the periods 1, 2 and 3. This gives six contracts for each connection, as shown in table 5.3.1.

Table 5.3.1: The six types of contracts that are modeled for Europe.

Contract number	**Type**	**Price segments**	**Number of hours per week**
1	Import	Off-peak - 5,7	63
2	Import	Base - 4,6	67
3	Import	Peak- 1,2,3	38
4	Export	Off-peak - 5,7	63
5	Export	Base - 4,6	67
6	Export	Peak- 1,2,3	38

The following connections from the continent to the Nordic countries are modeled:

- Connection to the Netherlands by the NorNed cable from south of Norway
- Connections to Germany from Denmark West, Denmark East and south of Sweden

5.3.1 The Netherlands

The Netherlands are connected to South of Norway by the NorNed cable. This has a capacity of 700 MW both ways. [1] The contract volumes are determined by the transmission capacity and the number of hours that the contract is used. The prices of the contracts are set by investigating prices in the Dutch market as well as the prices resulting from simulations in south of Norway. The prices were adjusted in order to get a realistic power flow between the countries, which is further described below. Information about the contracts with the Netherlands is given in table 5.3.2.

Table 5.3.2: Contracts modeled for the Netherlands

Contract number	**Contract type**	**Price [Eurocent /kWh]**	**Capacity [MW]**	**Number of hours per week**	**Volume [GWh]**
1	Import off-peak	5.2	700	63	44.1
2	Import base	6.4	700	67	46.9
3	Import peak	7.5	700	38	26.6
4	Export offpeak	5.2	700	63	44.1
5	Export base	6.4	700	67	46.9
6	Export peak	7.6	700	38	26.6

5.3.2 Power flow on the connection to the Netherlands

It is important that the connections with Europe are modeled so that reasonable energy flow between the countries is obtained. The energy flow on the connection is therefore evaluated to make sure that Norway will export most of the time during a wet year because it is cheaper to produce than to import and mostly import during a dry year because it is at this point cheaper than producing. Also, the flow should mainly go from Norway to the Netherlands during the high load periods and the other way during the night. This is due to the fact that the production is less expensive during the night in the Netherlands than in Norway because thermal generation has high start-up costs. It is thus profitable to run the power plants also during the night, which leads to low night prices in Europe.

The figures 5.3.1, 5.3.2 and 5.3.3 show results of the simulations of the power flow on the NorNed cable during three periods; Low Day, Norwegian High and Night. The positive values along the y-axis indicate import to South of Norway from the Netherlands. The 0 percentile-curve can be seen as a wet year in Norway, while the 100 percentile-curve represents a dry year.

One can see that during Low Day, the average flow goes from Norway to the Netherlands, while Norway has maximum import during a dry year. During a wet year, the export is at maximum.

Figure 5.3.2 shows that during the Norwegian High, the flow is mainly going from Norway to the Netherlands, except for during the winter and spring in a dry year.

The average power flow during the night goes from the Netherlands to Norway, except for in the spring, summer and fall in a wet year.

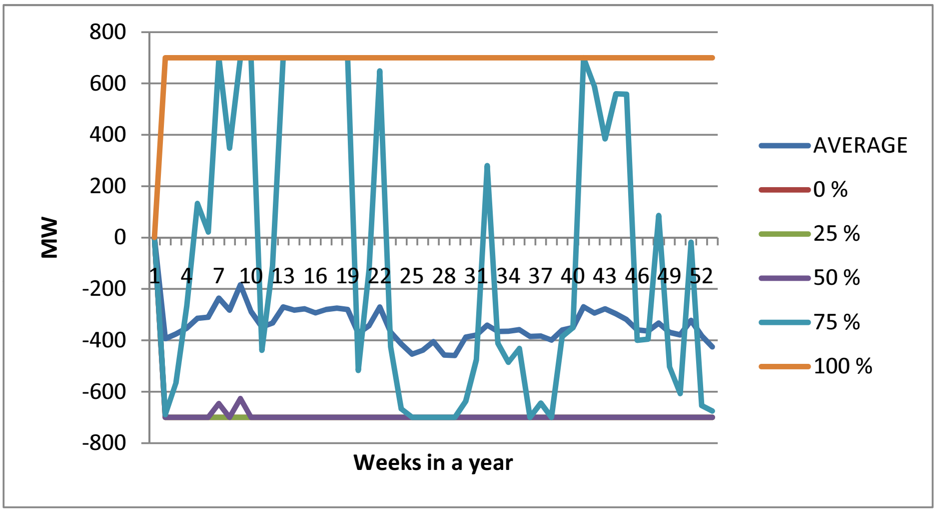

Figure 5.3.1: Average power flow between South of Norway and the Netherlands during Low Day.

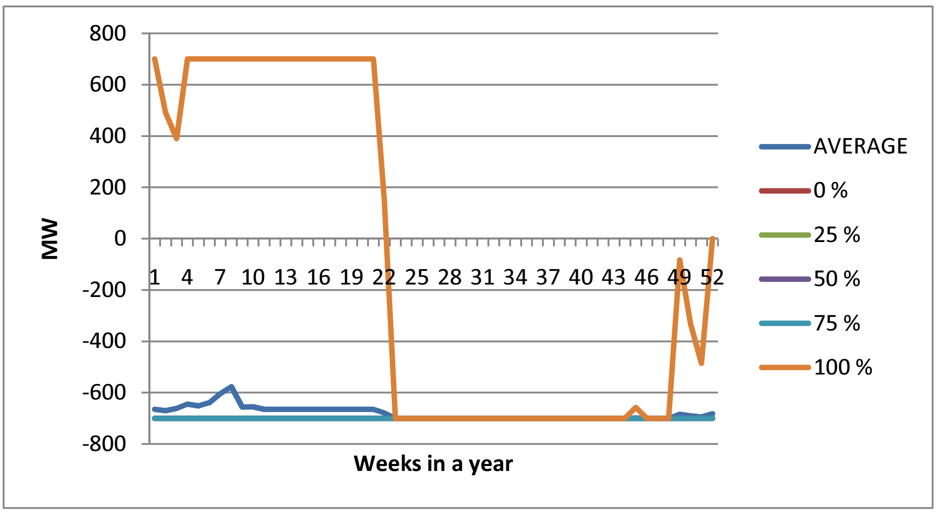

Figure 5.3.2: Average power flow between South of Norway and the Netherlands during Norwegian High.

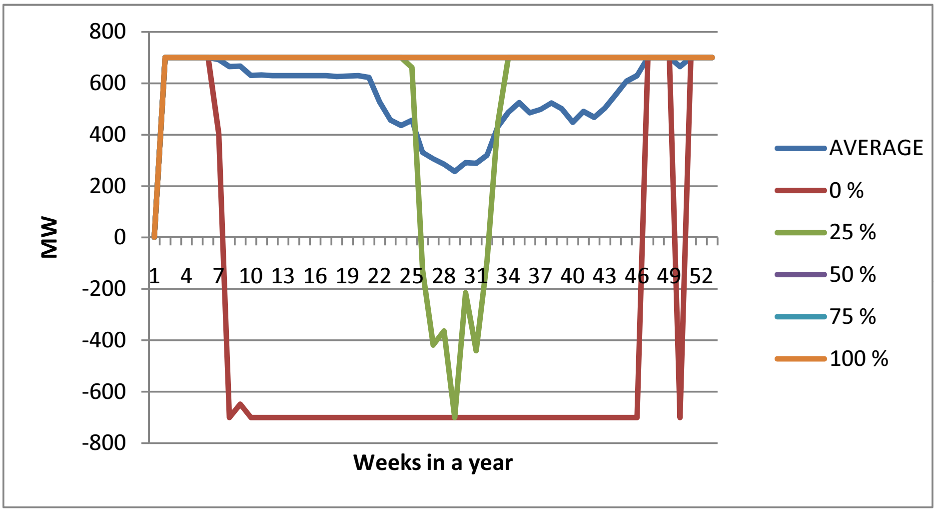

Figure 5.3.3: The average power flow between South of Norway and the Netherlands during the night.

5.3.3 Germany

The six contracts in table 5.3.1 are formulated also for Germany. Since the German and the Dutch markets are coupled, the prices in Germany are assumed to be relatively similar to the prices set in the contracts with the Netherlands. The prices that were given in 5.3.2 were thus used for the German contracts as well.

Germany's three connections to the Nordic countries with corresponding maximum transmission capacities are presented in table 5.3.3. Note that the connection to Germany is in reality only 600 MW, but since there is a cable going from Sweden to Poland as well, this connection is included by increasing the connection with this capacity of 600 MW. The assumption is reasonable as the prices in Poland is not very different from the German prices. [19]

Table 5.3.3: Connections between Germany and the Nordic countries with corresponding maximum transmission capacities. [1]

Connection	**Capacity to Germany**	**Capacity from Germany**
Denmark West	1500 MW	950 MW
Denmark East	600 MW	600 MW
Sweden	1200 MW	1200 MW

The exchange volume resulting from the capacities of the lines and the contract duration is for each contract given in table 5.3.4.

Table 5.3.4: Exchange volumes for the modeled German contracts.

Contract type	**Denmark West**		**Denmark East**		**Sweden**	
	Export [GWh]	**Import [GWh]**	**Export [GWh]**	**Import [GWh]**	**Export [GWh]**	**Import [GWh]**
Offpeak	94.5	59.85	37.8	37.8	75.6	75.6
Base	100.5	63.65	40.2	40.2	80.4	80.4
Peak	57	36.1	22.8	22.8	45.6	45.6

5.3.4 Power flow on the connections to Germany

Also for these connections, the power flow was analyzed to make sure that the contracts are reasonable modeled. The most important is, as for the NorNed cable, that the flow goes from the Nordic system to Europe during peak load periods and the other way during the nights in an average year. Wet and dry years should give the Nordic countries respectively more export and more import. In average, the import and export volumes should be almost the same.

Figures showing the power flow on the connections between Denmark East, Denmark West and Sweden during Low Day, Norwegian High and Night can be found in appendix B.2, showing reasonable results of the power flow. One small weakness is seen in the power flow between Sweden and Germany during Norwegian high, but it is assumed that this is not affecting the results of the simulations that will be done.

Chapter 6

Simulations

6.1 Simulation A - Reference Case

Simulation A involves a simulation of the reference case using the system model with the updated input data described in chapter 5, which is expected to behave as similar as possible to the power system.

6.1.1 Annual balance

Table 6.1.1: Average annual electricity balance for Norway, Sweden, Denmark and Finland, given in TWh.

	Hydro	**Thermal**	**Wind**	**Net Import**	**Demand**	**Rationing**
Norway	113.18	5.20	4.42	1.63	123.56	0.02
Sweden	62.36	84.97	3.12	3.22	152.78	0.03
Denmark	0.00	36.38	8.84	-6.58	38.10	0.00
Finland	12.07	59.15	0.56	4.77	76.56	0.04
NordPool	187.60	185.69	16.94	3.03	391.00	0.09

Table 6.1.1 shows the annual balance of production and consumption of electricity in Norway, Sweden, Denmark and Finland as average of the simulation years used in the model. The small unbalance between production and consumption represents transmission losses.

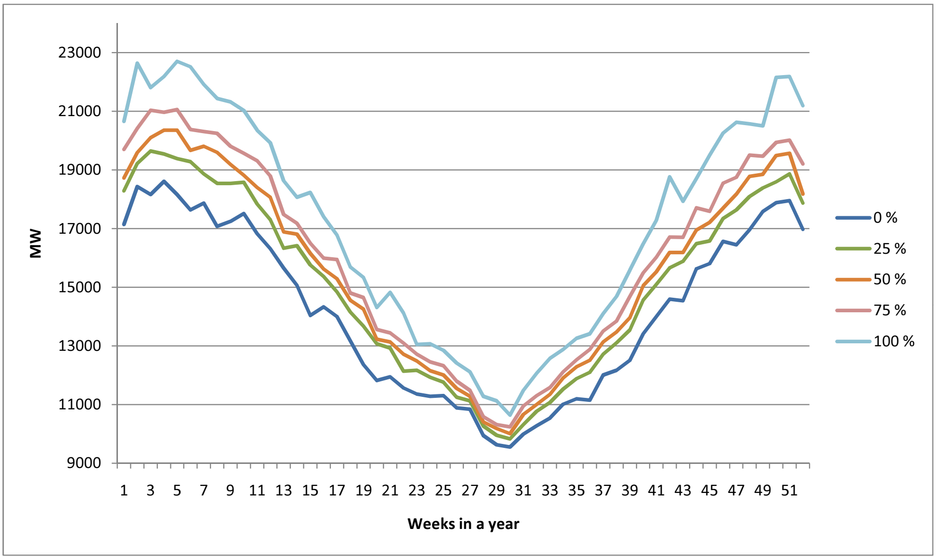

Figure 6.1.1: Maximum power consumption in Norway during the year, shown by 0, 25, 50, 75 and 100 percentiles

6.1.2 Maximum power consumption

Maximum power consumption is given in figure 6.1.1, showing 0, 25, 50, 70 and 100 percentile curves of consumption during the period Norwegian High. The curves show realistic results regarding annual variations of demand, but the peak is lower than what is observed in the power system, where a new consumption peak of 23 994 MW was observed during the winter 2009/2010 [20]. A reason that this is not present in the model is firstly the model's ability to distinguish between short and long term price elasticity of demand. When the original modeling of flexible demand is used, the units modeled as flexible demand is immediately disconnected when the market price exceeds the disconnection price. This coincides with the hours of high firm demand, which results in lower consumption peaks than what is realistic. Secondly, the model does not take use of heat pumps perfectly into account. When the temperatures get low, the efficiency of the heat pump is reduced, which increases the demand of electricity for heating.

6.1.3 Prices

The average prices[1] in all price periods are shown in figure 6.1.2. The most interesting factor in this case is the difference between the electricity prices in

[1] Average price means in this report the average price of all inflow alternatives

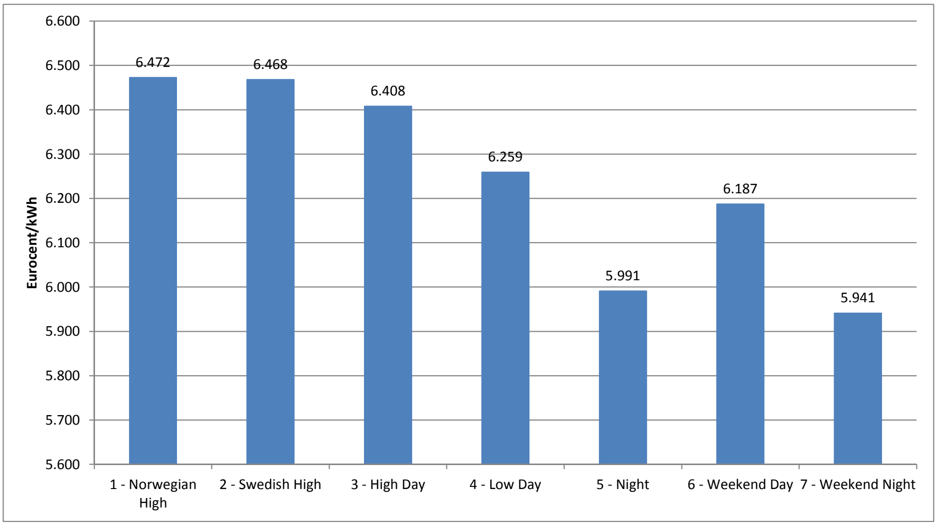

Figure 6.1.2: Average prices in all price periods in Østland in simulation A.

the peak load periods[2], and the low load period Low Day. These indicate if there is a potential and value of shifting load between the periods. The figure shows that the average price difference between the peak load periods and Low Day is 0,21 Eurocents/kWh. There are thus on average basis visible price differences over the day.

Nord Pool's data of electricity prices [2] in South East of Norway from the years are 2008 - 2009 are given in table 6.1.3. The peak load period is here set as an average of hour 9 and 18, while the low load period is an average of hour 15 and 16. The electricity prices in the market are somewhat lower than the simulations gave. This can be because the model is not perfectly adjusted to the real market variations at all times, which would require frequent updates of the model. As the important numbers are still the price differences between the peak load periods and low load periods, this is not problematic. The price differences in Nordpool appear close to the simulated prices, showing an average price difference of 0.19 cent/kWh. 2009 had very low electricity prices and lower price differences as well, which are not typical for the prices that are seen in 2010 and up till now in 2011.

The variation of prices between the inflow alternatives during the year as average of all price periods is illustrated in figure 6.1.3, shown by average and 0, 25, 50, 75 and 100 percentile curves. The 100 percentile curve's peak is at 24.3 cent/kWh. The figure clearly shows that there are relatively few price variations represented in this dataset. There are extreme cases given by the 100 percentile curve, but

[2] Peak load periods are from now defined as the periods Norwegian High and Swedish High. When referring to the price in peak load periods, the average of the prices in Norwegian High and Swedish High is used.

Year	Average price [EuroCent/kWh] Peak load periods	Low load periods	Price difference [EuroCent/kWh]
2008	5.68	5.45	0.23
2009	3.52	3.46	0.06
2010	5.80	5.54	0.26
Average	5.00	4.81	0.19

Table 6.1.2: Electricity prices and price differences for the peak and low load periods in the price area Norway South East, the years 2008-2010 [2]

between the 20 and 75 percentile curve, the prices variations are very small, the prices are mostly varying between 5 - 7 cent/kWh.

The 100 percentile curve is mainly represented by the dry year 1970. To show this, figure 6.1.4 is given, where the prices in year 1970 are excluded. The maximum price is now at only 10 cent/kWh. Identifying the representation of such situations is important because it is mainly in these cases that the largest value of load shift can be achieved. That is, if it is a situation of power shortage and the price cross is obtained at the very steep part of the supply curve cf. section 2.4. It is in these situations large price differences between the periods, and load shift between these periods will thus reduce the peak prices considerably.

The variation of price differences between the peak load period and Low Day is shown in figure 6.1.5. The largest price difference between the peak load periods and Low Day is at 38.625 cent/kWh.

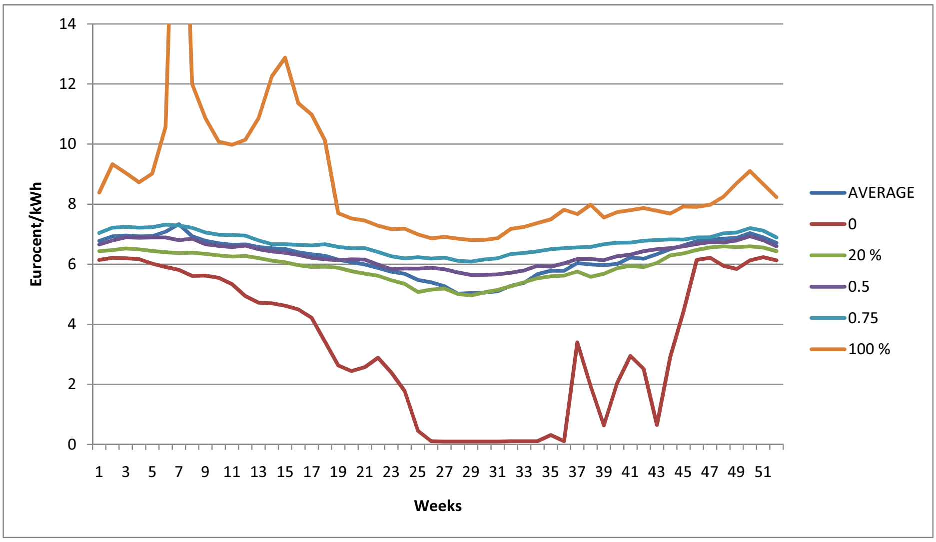

Figure 6.1.3: Variation of prices through the year in simulation A

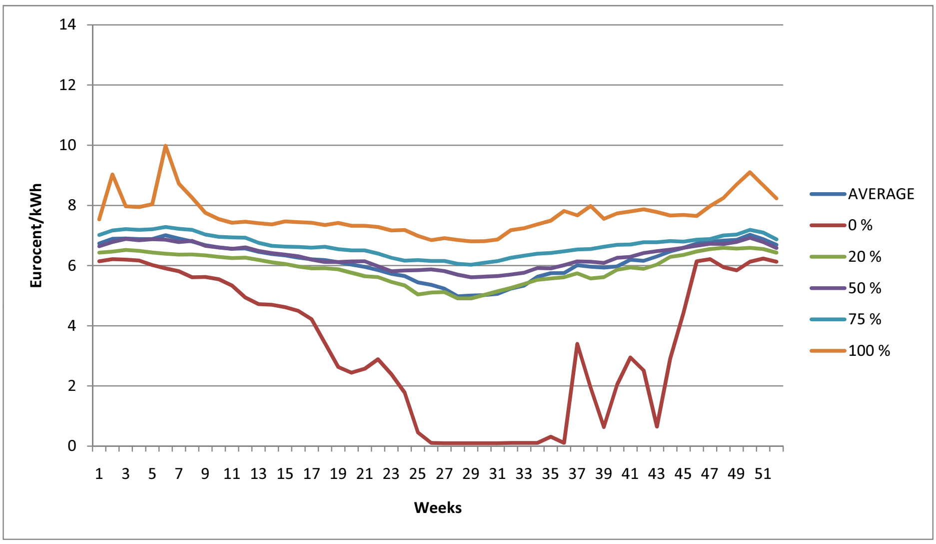

Figure 6.1.4: Variation of prices as average of all price periods through the year in simulation A shown by percentiles of all simulation years excluded 1970.

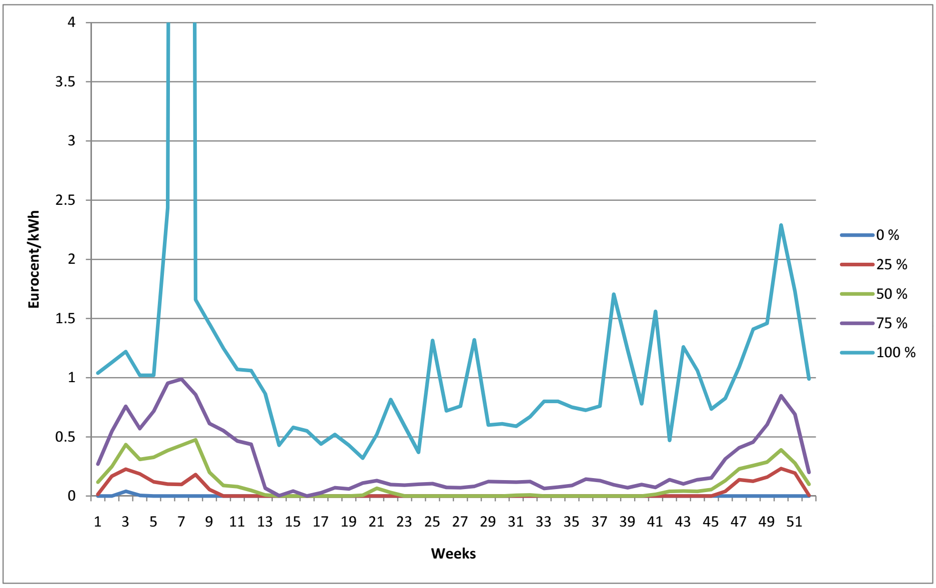

Figure 6.1.5: Price differences between the peak load periods and Low Day through the year in simulation A given by percentiles.

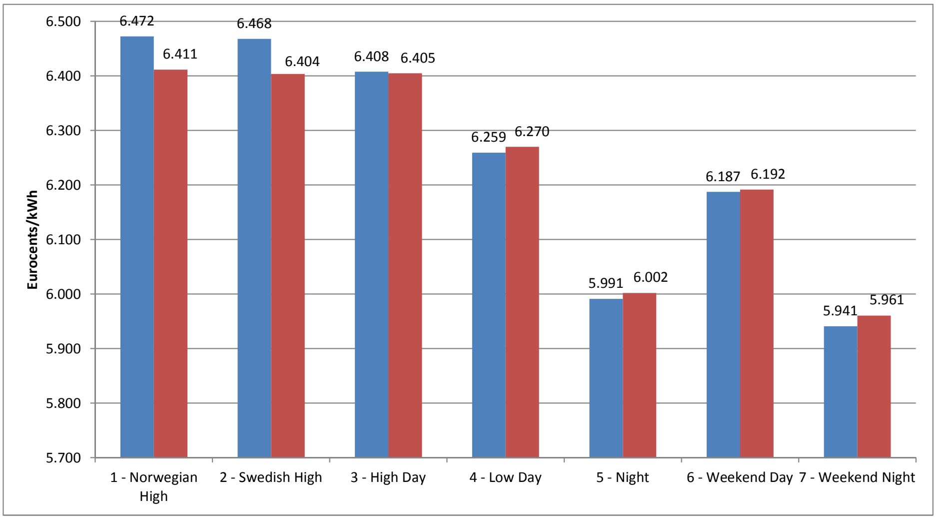

Figure 6.2.1: The average prices in each price period before(blue columns to the left) and after(red columns to the right) the load shift implemented.

6.2 Simulation B - Load Shift

Simulation B is based on the same system model as in simulation A, except that 600 MW is moved from the peak load periods Norwegian High and Swedish High to the low load period Low Day in Norway. The load shift is implemented according to the description in 4.4.

The simulation is run both with a model that is calibrated after the load shift is implemented, and with one that uses the same water values as calculated in simulation A.

6.2.1 Prices

The prices resulting from the simulations without recalibration of the model are given in appendix C.1. These were not very different from the prices found by the calibrated model, given in figure 6.2.1. The average prices in the peak load periods have decreased significantly from simulation A, by in average about 0.06 cents/kWh. The prices during low load is increased by about 0.01 cents/kWh.

In order to find the time of when the large price reductions occur, it has been looked into the maximum, the average and the minimum change in the prices in the peak load periods of the inflow alternatives. This is given in figure 6.2.2. As one can see, the largest reduction occurs in week 7, where the price is reduced by

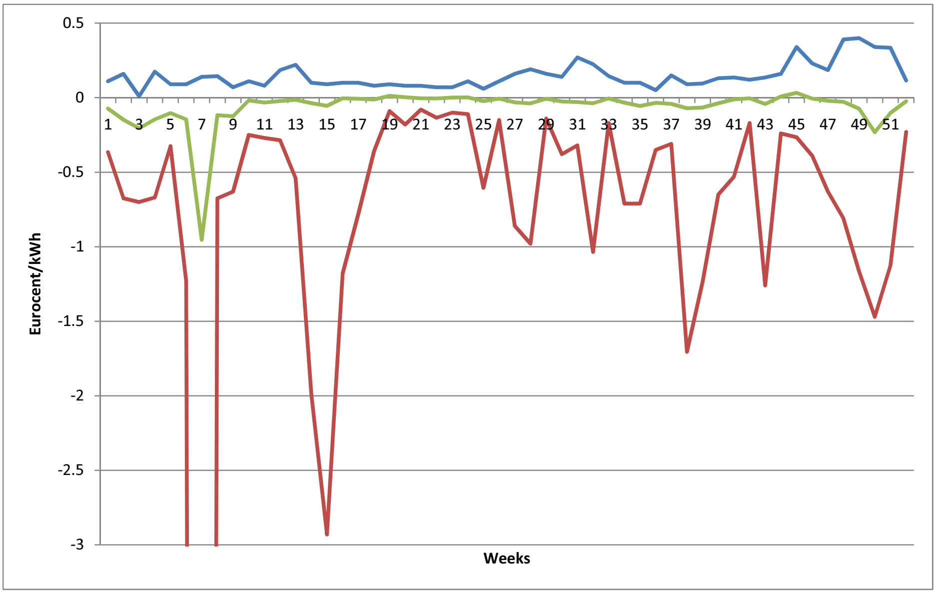

Figure 6.2.2: Price change in the peak load periods from the reference case to the load shift case, shown by maximum, average and minimum change of all inflow alternatives.

33.02 cents/kWh. The situation is given by the inflow in 1970. This proves that the load shift has large effect in extreme cases.

The exact effect of load shift in extreme situations is closer analyzed by looking at the prices in week 7 in 1970. In this situation the price differences between the periods are very large. This means that the price cross is obtained at the limit of maximum power capacity, and the potential of an effect of shifting load between the periods is thus large. The average price changes in all price periods in week 7 1970 are given in figure 6.2.3, clearly proving the large effect that load shift has in these situations. The prices in the peak load periods are reduced from above 50 cent/kWh to below 20 cent/kWh. The prices during Low Day have decreased slightly, which is the opposite of expected effect. This is explained by that the model was calibrated before running this simulation, which implies that new water values are calculated. The stochasticity of the water value calculation give varying water values for each simulation. This witnesses of an uncertainty in the exact numbers in the results of the simulation. It is still clear that a large effect of load shift is achieved, although the exact numbers are uncertain.

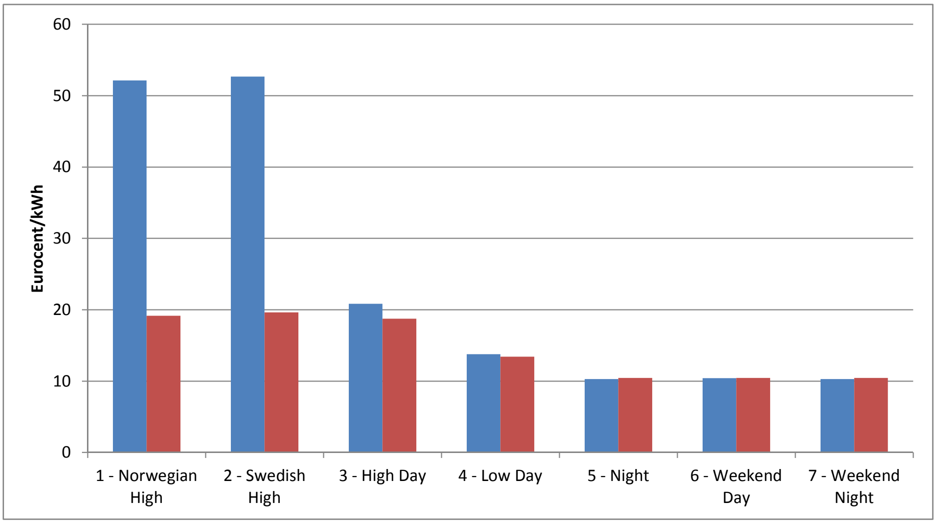

Figure 6.2.3: Prices in all periods before and after load shift in week 7 in 1970 in simulation A and B.

6.2.2 Socio-economic Surplus

The difference in social surplus from simulation A to simulation B when using a calibrated model is presented in table 6.2.1, showing the net gain of shifting load from the peak load periods Norwegian High and Swedish High to the low load period Low Day.

An adjustment of the social surplus calculated for simulation B is made according to the theory described in appendix A.2. Equation (4.4.1) gives an adjustment A of

$$6000MWh/week \cdot 52weeks \cdot 300.1Eurocent/kWh = 936.312MEUR$$

where the analysis period is one year, load shift is implemented for 52 weeks in the analysis period and the disconnection price p_{LS} is set to 300.1 Eurocent/kWh, which is slightly above the rationing price 300 cent/kWh.

The results without a calibrated model gave a net gain of load shift of -0.052 MEUR, which is close to what was found in [6]. The number is clearly not realistic, as it indicates no gain of load shifting. This proves that the system model is more sensitive for adjustments than expected, a new calibration of the model is necessary to get an optimal reservoir handling. More detailed numbers on the calculation of social surplus by the simulation without calibration is given in appendix C.1.

Table 6.2.1: Difference in social surplus from simulation A to simulation B

Social surplus simulation B	301315.3	MEUR
- Social surplus simulation A	300358.8	MEUR
=	956.52	MEUR
-Adjustment	936.312	MEUR
Net gain	**20.208**	**MEUR**

The exact value of difference in social surplus is uncertain due to that different water values are used in simulation A and simulation B. A clear positive value of load shift is still present.

6.3 Simulation C - Improved wind modeling

Modeling of wind power production is improved compared to the model used in Doorman and Wolfgang's report [6]. The dataset used in this work allows variation of wind production within the week, between weeks and between years, whereas the wind modeling used in Doorman and Wolfgang's work only gave variation between years and not within the week and between years.

Variation within the week is however not taken into account in simulation A, B, D and E. The reason is that the model requires that start-up costs of thermal power plants is included in the simulation in order to use the functionality. Simulation C involves a simulation of the system model with start-up costs, i.e variation within the week is included. This is performed in order to see if larger price differences between the periods of a day are identified. It was intended to include the variation in simulation D and E as well, but due to problems in the simulations when these different functionalities were combined, this was unfortunately not manageable. It is still of interest to see the general effect of including variation of wind production within the week as an indicator of how it affects the results.

The price variation is not changed very much from simulation A, shown in figure 6.3.1, where the peak is at 23.84 cent/kWh. Figure 6.3.2 shows that the largest price differences between the peak load periods and Low Day is increased, the largest price difference is at 36.075 cent/kWh. The average differences between the periods are slightly higher than the differences found in simulation A. It is however found that a load shift gives an average smaller reduction of the peak load prices than in simulation B, the reduction is now 0.048 cent/kWh. The effect in the extreme situations is also clearly smaller, the largest price reduction is now of 8.46 cent/kWh. An explanation for this is that since the variation of wind power production has caused larger differences between the periods, the

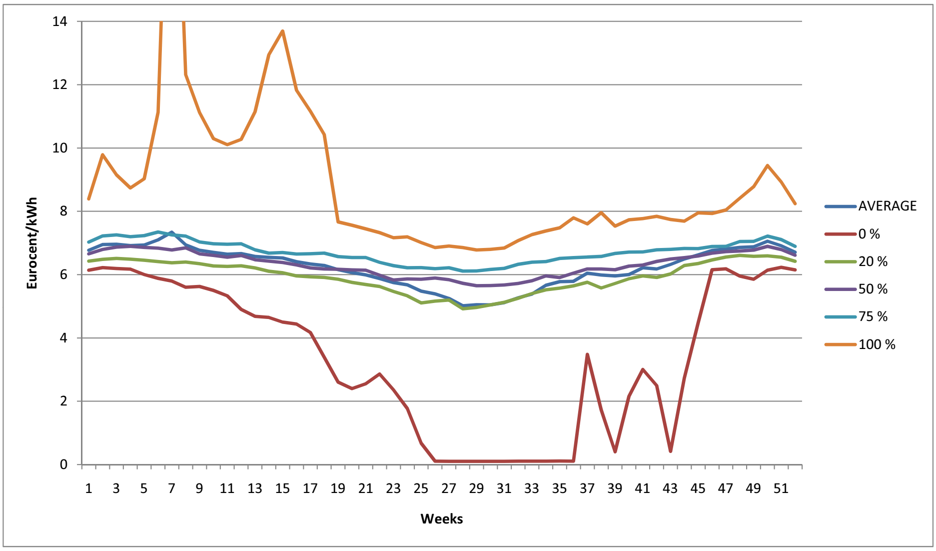

Figure 6.3.1: Variation of prices through the year in simulation C.

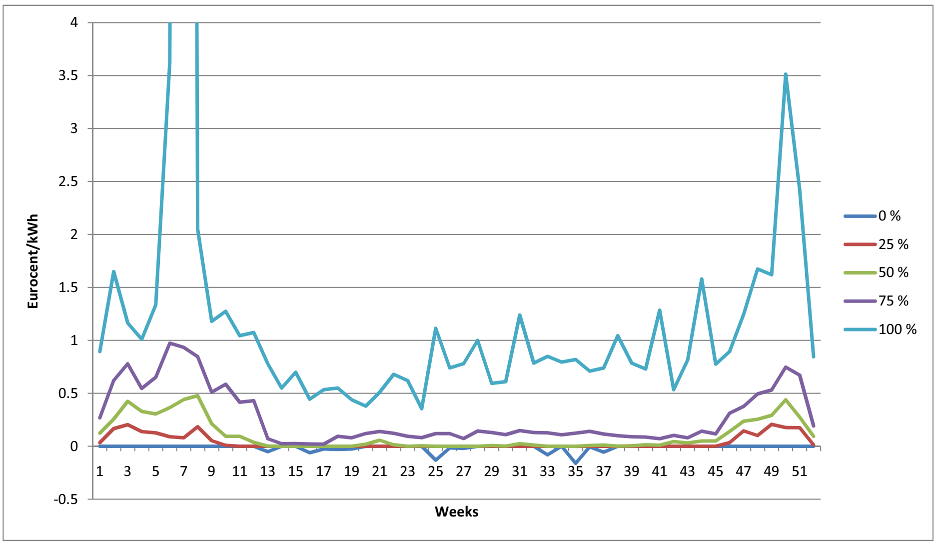

Figure 6.3.2: Price differences between the peak load periods and Low Day through the year in simulation C given by percentiles.

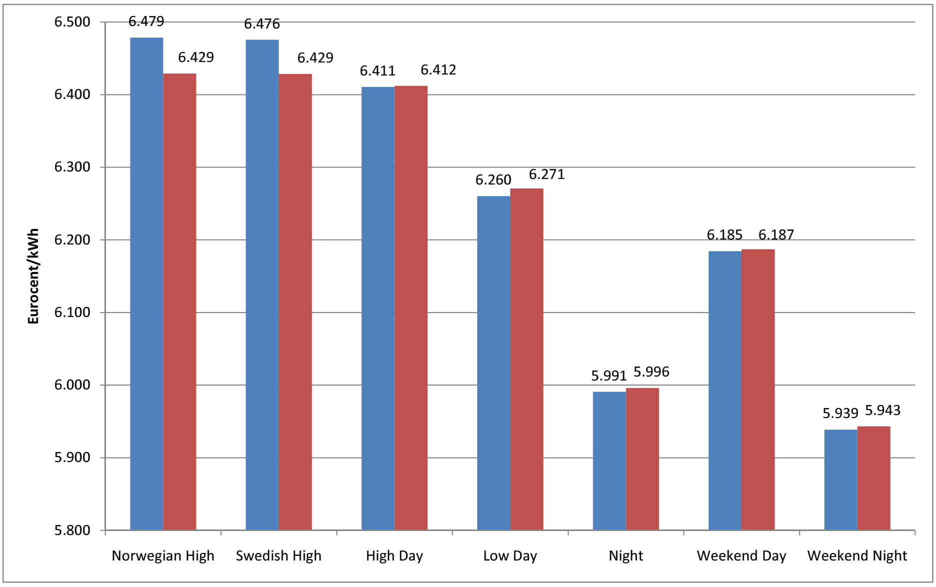

Figure 6.3.3: The average prices in each price period before and after the load shift implemented in simulation C.

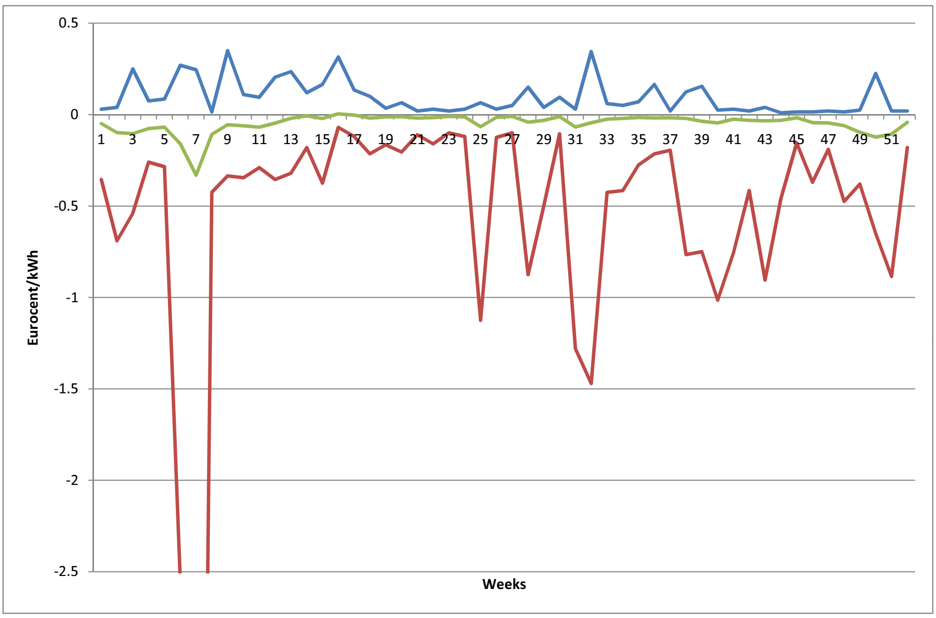

Figure 6.3.4: Price change in the peak load periods from the reference case to the load shift case, shown by maximum, average and minimum change of all inflow alternatives in simulation C.

prices are to a larger extent decided by the wind power production, rather than the size of the load in the given period. The load shift has thus a smaller impact on the prices than the variation of wind power production has, which causes a smaller value of load shift although the price differences are larger.

6.4 Simulation D - Improved modeling of flexible demand and implementation of quadratic losses

Improved modeling of flexible demand and implementation of quadratic losses are utilized in this simulation in order to obtain a more realistic model. Simulations are first run with each of the elements included, showing the general impact of each of them. These simulations are not calibrated. After this, a simulation of the model with both elements implemented are run, where the effect of load shift again is investigated. The load shift case is simulated both using a calibrated model and an uncalibrated model.

6.4.1 Improved modeling of flexible demand

Modeling of flexible demand is improved by implementing gradual consumption adaption, using the method described in 3.5. The original modeling gives an unrealistic reduction of demand at high prices, as consumption is immediately disconnected at high price levels. Implementation of gradual consumption adaption will result in that flexible demand will to a larger extent be modeled as long term price elastic rather than short term price elastic, which is more consistent with the real market behavior.

Based on the discussion in 3.5, it was decided to use linear adaption. This method is expected to give a faster disconnection for a significant volume of flexible demand than the method asymptotic adaption does. There are little experience with the use of this method, and thus challenging to set accurate parameters. In order to choose a reasonable value as inertial parameter, three parameters of different sizes are tested. Further, the value giving the most realistic effect on the consumption curve and the prices will be used in a calibrated simulation where implementation of quadratic losses as well is included.

The three inertial parameters 20%, 50% and 80% are tested in terms of consumption levels and prices. Each of the parameters are tested for both the reference case and the load shift case. For all simulations, adaptive expectations of two weeks are used, i.e present week and previous week, each weighted 50%.

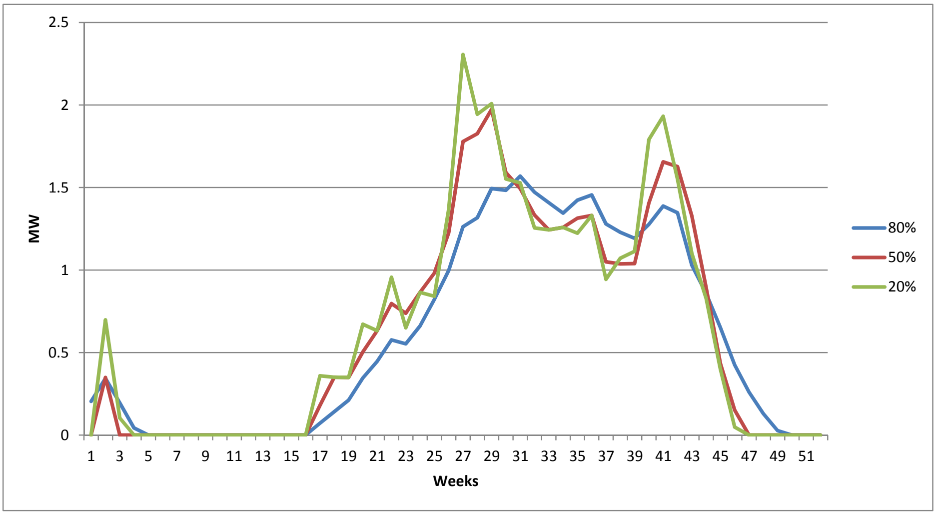

Figure 6.4.1: Average consumption of one flexible unit for three different parameters.

Flexible consumption

Figure 6.4.1 shows the average consumption over the year for one unit that is modeled as flexible demand in the area Østland. The unit has a disconnection price of 4.39 cent/kWh. The results of simulations with the three different values of the inertial parameters are shown. Using 20% as inertial parameter gives fast consumption changes with varying prices; the curve increases rapidly when prices decrease and the other way around. A parameter of 80% gives a much slower reaction on prices; an apparent price reduction in around week 26 - 30 does not affect the load curve enough to make it reach maximum. This indicates that the prices have to stay high over a period longer than these 4 - 5 weeks in order to make the curve reach maximum. Neither does the consumption decrease strongly when the prices increase again, which can be observed by the behavior of the 20% and 50% curves around week 32 - 40. The behaviour of the 80% consumption curve is more consistent with the real market, where it takes long for industry and boilers to adapt to the market prices, cf. section 3.5. The 50% parameter curve is somewhat between the curves of 20% and the 80%. It does change acoording to price variations, but reaches a lower maximum than the 20% parameter curve does.

Total flexible consumption in Østland consists in the model of 7 units, each having a specified disconnection price. Figure 6.4.2 shows the curves for total consumption in the area, having the three parameters implemented. The curve does not change very much with the varying parameters. The reason is that one large unit is modeled at a disconnection price of 18.75 cents/kWh, which means

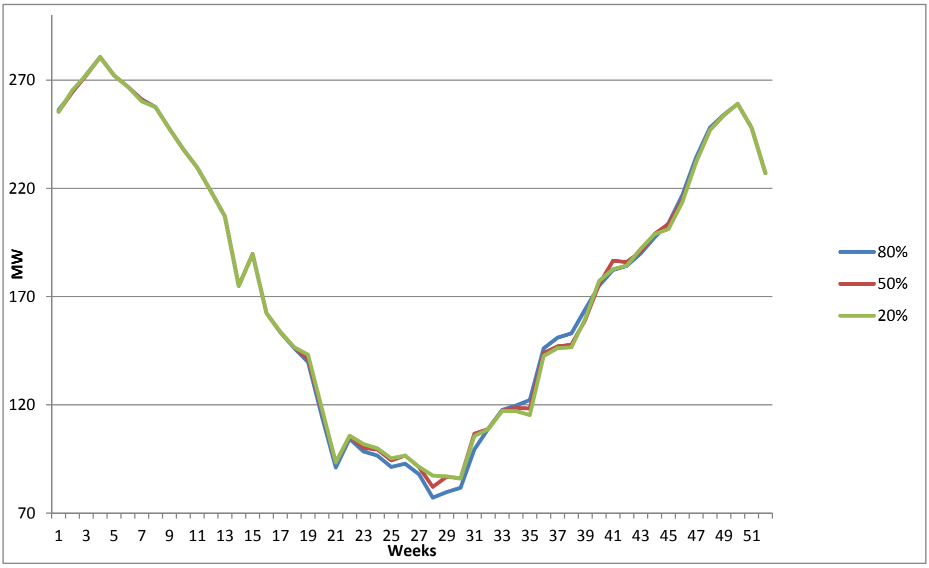

Figure 6.4.2: Average consumption of total flexible consumption in Østland for three different parameters.

that the consumption of this unit almost never react on market prices. As shown in section 6.1.3, the prices almost never exceed this level, only in 1970. Since the unit holds a very large share of the total flexible demand in the area, the variations of the other units are insignificant for the total flexible consumption curve. To see the effect of gradual consumption adaption on the total flexible consumption, one has to look at the situation in 1970, when the large unit disconnects.

Figure 6.4.3 shows total flexible consumption in Østland for only the price period Norwegian High during the year 1970. The only flexible unit that is connected is the large unit that was previously mentioned. The curve shows that this unit disconnect shares of the volume only in one week of the year, which is week 7. It is also evident that changing sizes of inertial parameters in this case give varying levels of disconnection volumes.

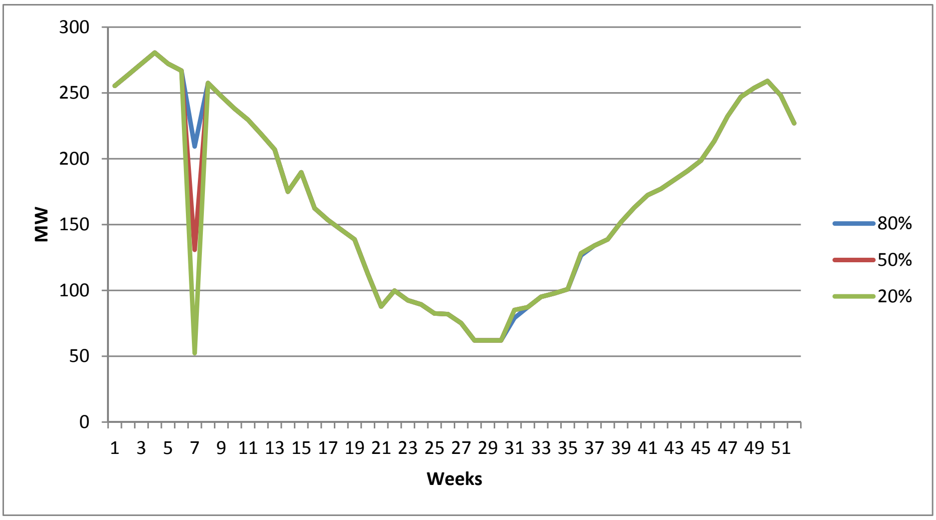

Figure 6.4.3: Average consumption of total flexible consumption in Østland in 1970 in the price period Norwegian High for three different parameters.

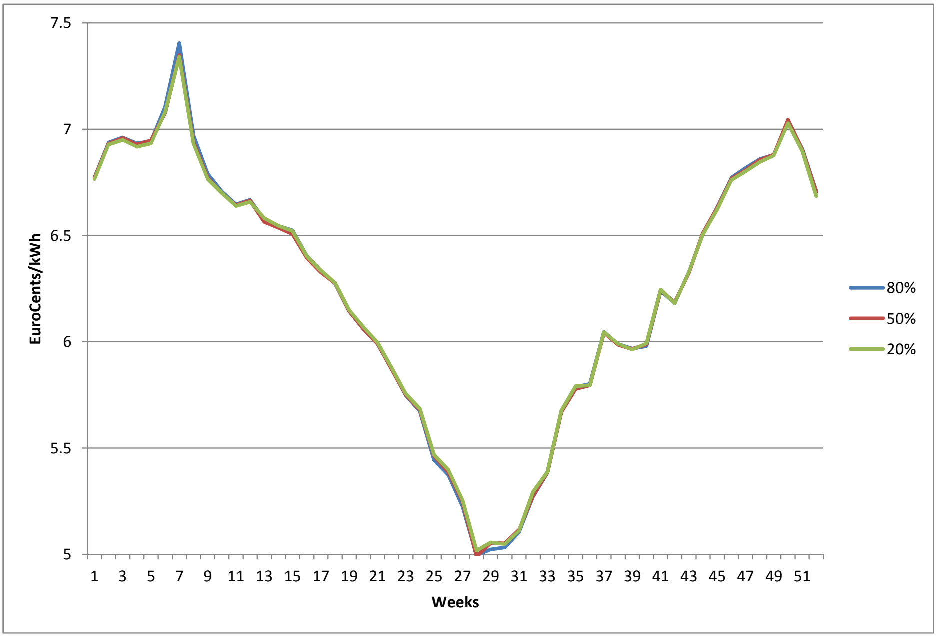

Figure 6.4.4: Average prices through the year for three different parameters.

Prices

The average(of all inflow alternatives and price periods) price variation during a year in Østland with inertial parameters implemented is illustrated in figure 6.4.4. It is clear that the average price changes for changing values of inertial parameters are very small. This is due to the fact that the introduction of gradual adaption has little effect on the total flexible consumption curve, as discussed in the previous section. A peak is still identified for the parameter 80%, which is expected since this parameter givess the lowest disconnection.

The prices in 1970 are analyzed in order to see if the price peak changes with varying inertial parameters. The yearly variation of prices, as an average of all price periods in 1970 in Østland is illustrated in figure 6.4.5. A maximum is as expected identified for an inertial parameter of 80%.

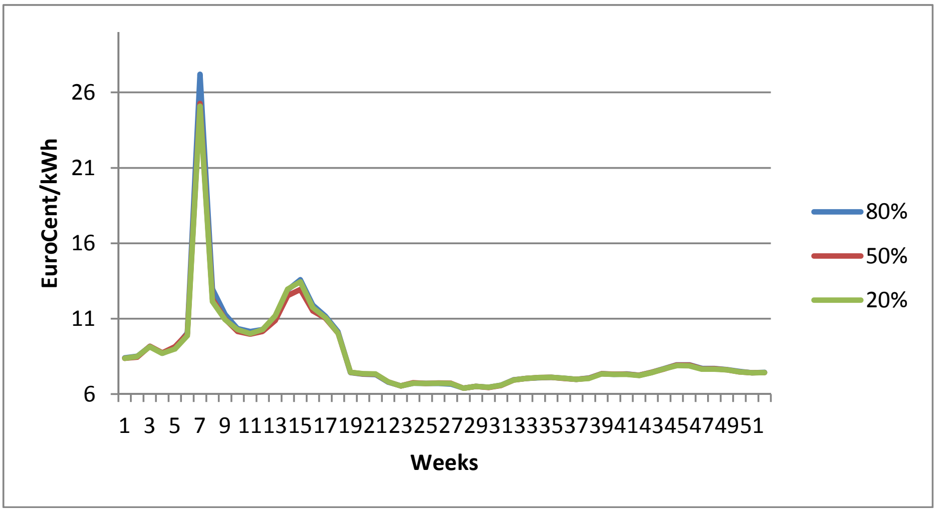

Figure 6.4.5: Prices as average of all periods in the dry year 1970 for three different parameters.

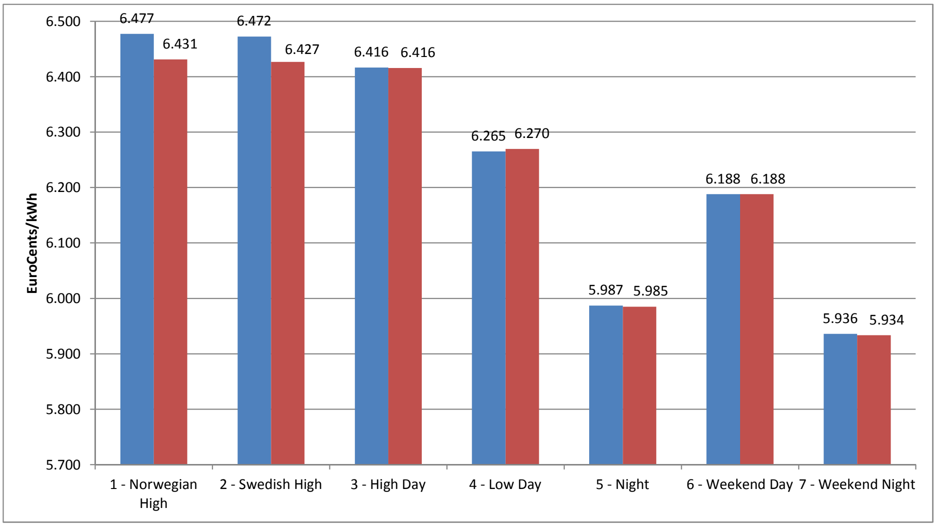

Figure 6.4.6: Average prices in all periods before and after load shift with the parameter 80% implemented.

Effects of load shift

The results of simulations of the reference case and the load shift case are presented, showing the price changes between the two cases. The implementation of three inertial parameters gives in total three figures.

The most important observations from the figures are summed up in table 6.4.1, showing the average price differences between the peak load periods and Low Day, in addition to the price reductions during the peak load periods due to load shift for all the parameters. It is found that the price difference between the peak periods and Low day in the reference case stays quite constant for all parameters, indicating that the price increase occur in all price periods with increasing parameters. It is also shown that the parameters 20% and 80% give respectively the highest and lowest price reductions during the peak load periods. Simulation B gave a peak price reduction of 0.06 cent/kWh. This shows that including gradual consumption adaption reduces the effect of load shift. This is looked closer into by investigating the prices in week 7 in 1970.

It is shown in table 6.4.2 that the peak prices in week 7 in 1970 obtains less price reduction from a load shift the higher the inertial parameter that is used. The reason is that gradual consumption adaption makes a smaller share of flexible demand disconnect, where the size of the volume decreases with higher parameters.

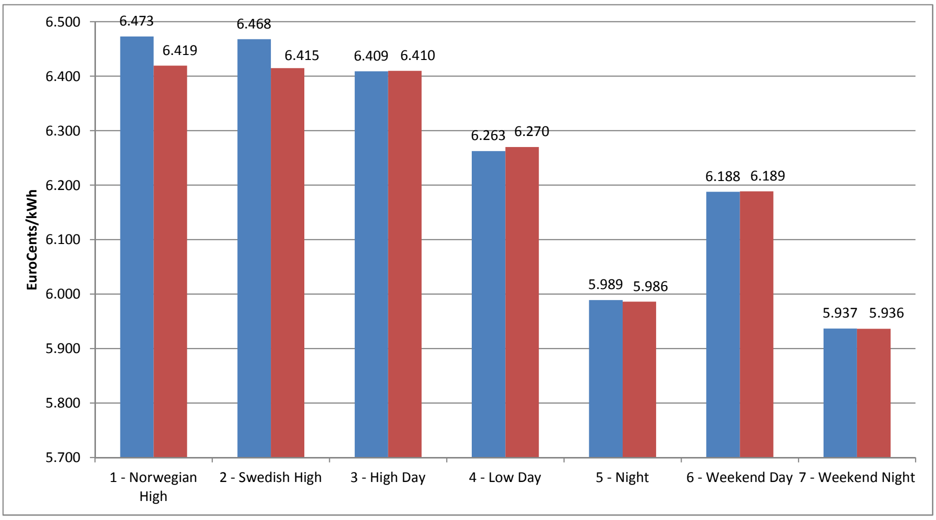

Figure 6.4.7: Average prices in all periods before and after load shift with the parameter 50% implemented.

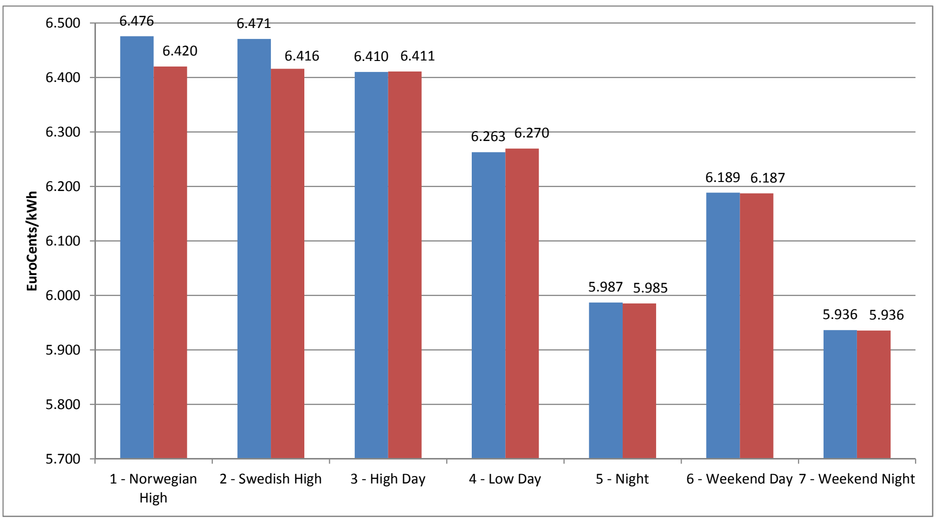

Figure 6.4.8: Average prices in all periods before and after load shift with the parameter 20% implemented.

Table 6.4.1: Price reduction in the peak load periods and the price differences between the peak load period and Low Day, given in Eurocent/kWh.

Inertial parameter	**Peak price reduction**	**Price difference peak periods/LD in reference case**
80 %	0.046	0.210
50 %	0.053	0.208
20 %	0.055	0.210

Table 6.4.2: Price changes from the reference case to the load shift case in all price periods in week 7 1970 given in Eurocent/kWh for all tested parameters.

Parameter		NH	SH	HD	LD	N	WD	WN
80 %	**Reference case**	52.67	52.67	35.88	16.82	10.66	11.1	10.66
	Load shift case	46.35	46.35	36.67	14.77	10.37	10.88	10.37
50 %	**Reference case**	52.67	52.67	25.37	14.36	10.4	10.96	10.4
	Load shift case	25.38	27.84	24.33	14.3	10.23	10.76	10.23
20 %	**Reference case**	52.14	52.14	24.5	15.41	10.32	10.75	10.32
	Load shift case	21.62	21.62	20.44	13.26	10.29	10.49	10.29

Choice of inertial parameter

Modeling the elasticity of flexible demand is a challenging task, as it involves many complex elements. The disconnection prices and volumes of power intensive industry depends on the types of industry, their strategy and their markets knowledge, while total disconnection volumes of electric boilers will to a large extent depend on factors such as oil prices or simply the effort they feel that takes for them to switch from electricity. It is difficult to draw conclusions of demand elasticity from existing consumption and price data, as there are a number of other factors contributing to the variations seen in demand. Figure 6.4.9 and 6.4.10 show respectively the system price in Nordpool through 2010 and the consumption of flexible demand, i.e electric boilers and power intensive industry in 2010. As one can see, no obvious conclusions of price elasticity can be drawn from this data; the price peaks that occur do not coincide with lower consumption. It is, as mentioned a number of other contributing factors. Finding good estimates of the elasticity would require large analyses and studies of data.

The choice of inertial parameter is in this study therefore based on some qualitatively considerations of the results of flexible consumption in Østland 1970 in figure 6.4.3, since this curve is, as has been shown, decisive for the effect of implementation of gradual consumption adaption in this case. A choice of using a parameter of 80% has been made based on following considerations: It is assumed that a rapid increase of price over a week such as in week 7 in 1970 is

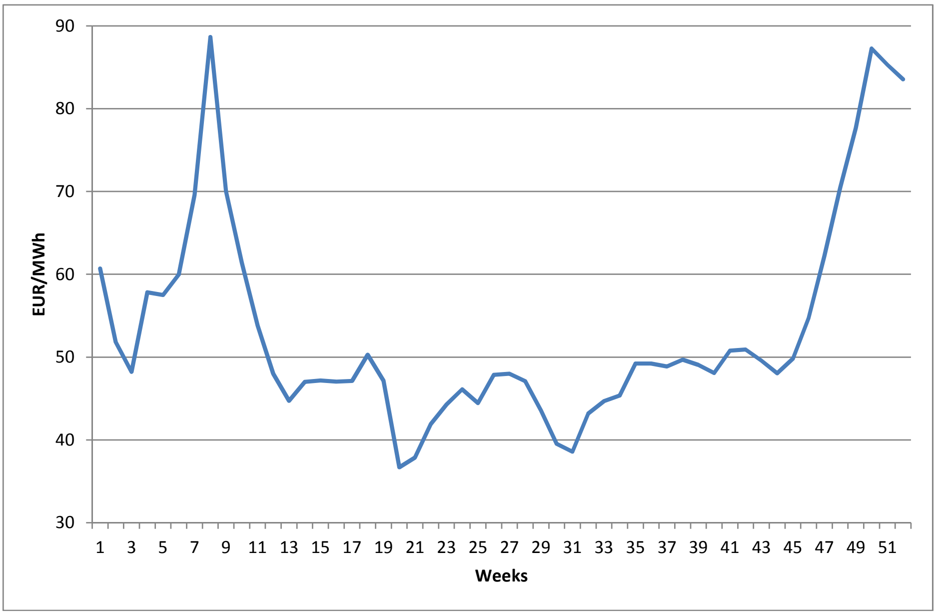

Figure 6.4.9: The system price in Nordpool during 2010 [2]

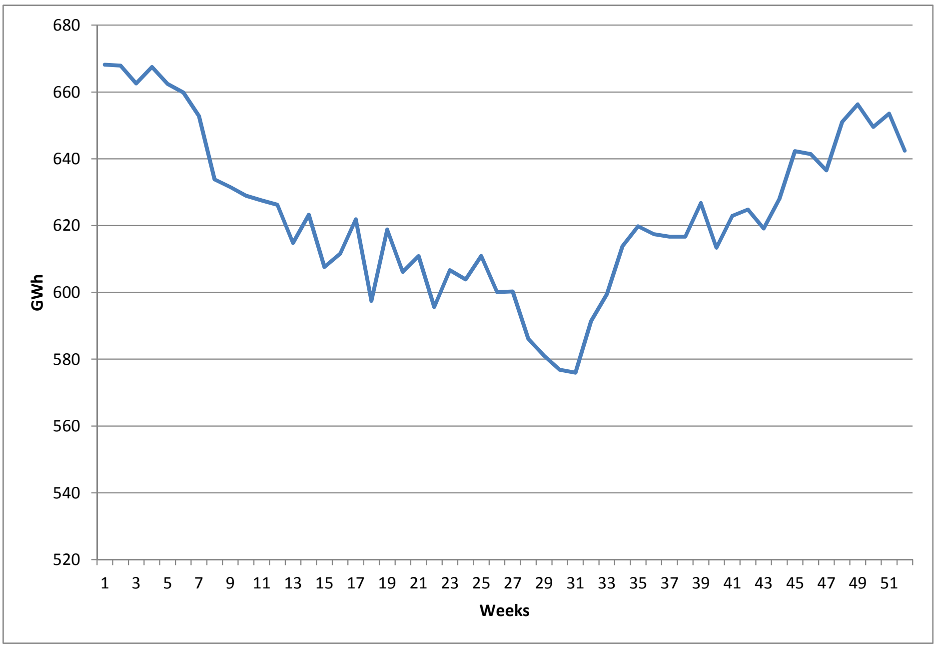

Figure 6.4.10: Flexible consumption in Norway during 2010 [7]

not sufficient to shut down large volumes within the industry. The parameters 20% and 50% give relatively large disconnection volumes. It is further assumed that the time for boilers to disconnect is somewhat shorter than for industry [21], and that a week of high prices is for some customers enough to switch from electricity to other fuel types. This means that overall, a relatively small part of flexible consumption will be disconnected when high prices occur for one week. The parameter of 80% is therefore assumed to give the most realistic modeling of flexible demand of the three parameters. This will be used in simulations where quadratic losses as well is included.

6.4.2 Implementing quadratic losses

Quadratic losses are included in this simulation according to the theory described in section 3.6. When testing the implementation is was found that the the method requires that the loss coefficient defined in the dataset needed to be updated in order to give reasonable simulation results. This is described in appendix C.2. The effect of using quadratic losses is investigated by looking at the duration curves for transmission and changes in prices and price differences between the periods.

Duration curves for transmission

The duration curve in figure 6.4.11 shows the general effect of using quadratic losses instead of linear losses. Note that the duration of each price periods is not taken into account here, which means that it is not a real duration curve, but the main effect of implementing quadratic losses is still shown. The connection that here is shown is randomly chosen, as the point is to show the general effect of implementing quadratic losses on the duration curves. One can see that the maximum capacity is somewhat shorter utilized, while there are less hours that the capacity of the lines is not utilized at all. The reason is that with quadratic losses it is more expensive to utilize the lines when transmission is reaching maximum capacity.

Prices

The average price differences between the peak load periods and Low Day is increased from 0.211 to 0.237 cent/kWh. This is shown in figure 6.4.12. The two compared simulations are based on the same water value calculation. The peak load period prices are considerably increased, while the prices in Low Day are somewhat increased, but less than in the peak load periods. The prices in the off-peak periods are staying at the same level as by linear losses. The reason is that it is now more expensive to import during the high load periods, and

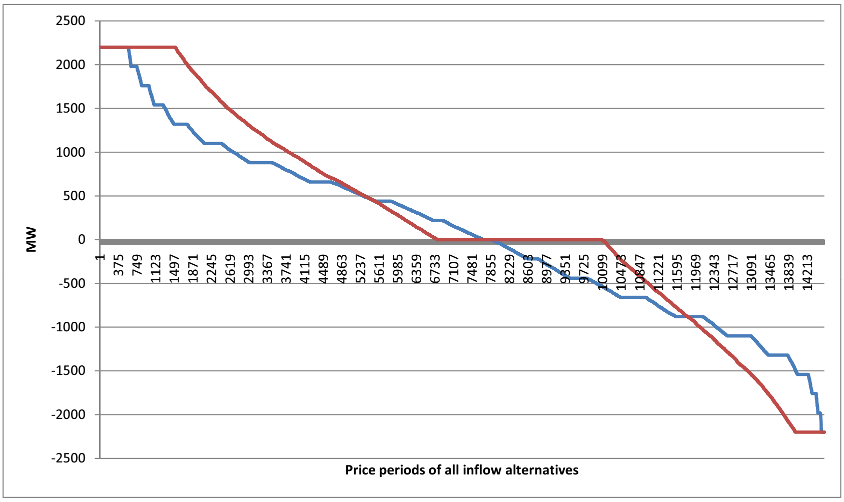

Figure 6.4.11: Duration curve for transmission between Norway East and Sweden Mid-West with linear losses(blue line) and without quadratic losses(red line).

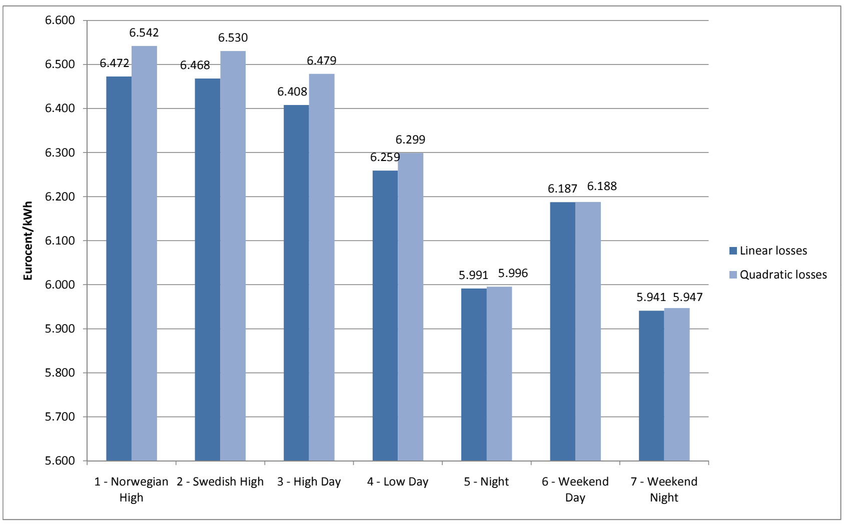

Figure 6.4.12: Comparison between the average prices resulting from simulations with linear losses and quadratic losses.

as Østland is net importer of electricity, it increases the prices in the high load periods.

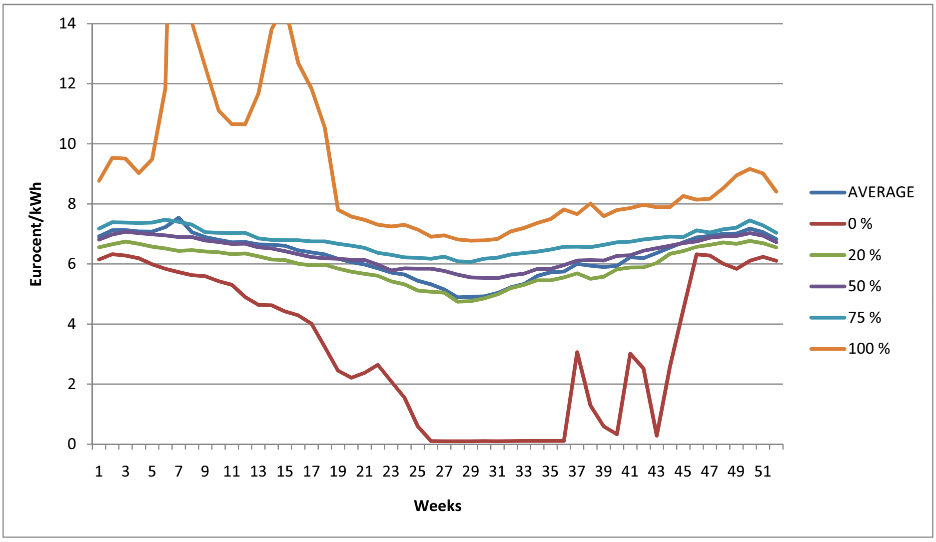

Figure 6.4.13: Variation of prices through the year in the reference case using gradual consumption adaption and quadratic losses.

6.4.3 Combining gradual consumption adaption and quadratic losses

Implementing these two functions should together give a more realistic model than was used in simulation A and B. For gradual consumption adaption the inertial parameter of 80% is used. Simulations both for the reference case and for the load shift are run. The load shift case is simulated using a calibrated model and an uncalibrated model.

Reference case

The reference case simulation gives higher price differences between the peak load periods and Low Day than observed in the earlier simulations. The average price difference is now increased to 0.241 cent/kWh. This is shown in figure 6.4.15, where the average price of the load shift case as well is included. The increased price difference is mainly caused by increased price peaks; the overall price variation is not very much changed, shown in figure 6.4.13. Figure 6.4.14 shows the varying price differences between the peak load periods and Low Day, where one can see in that the 100 percentile line is higher than in simulation A, but the differences below the 75 percentile curve stays at about the same level. The largest difference between the peak load periods and Low Day is of 36.95 cent/kWh.

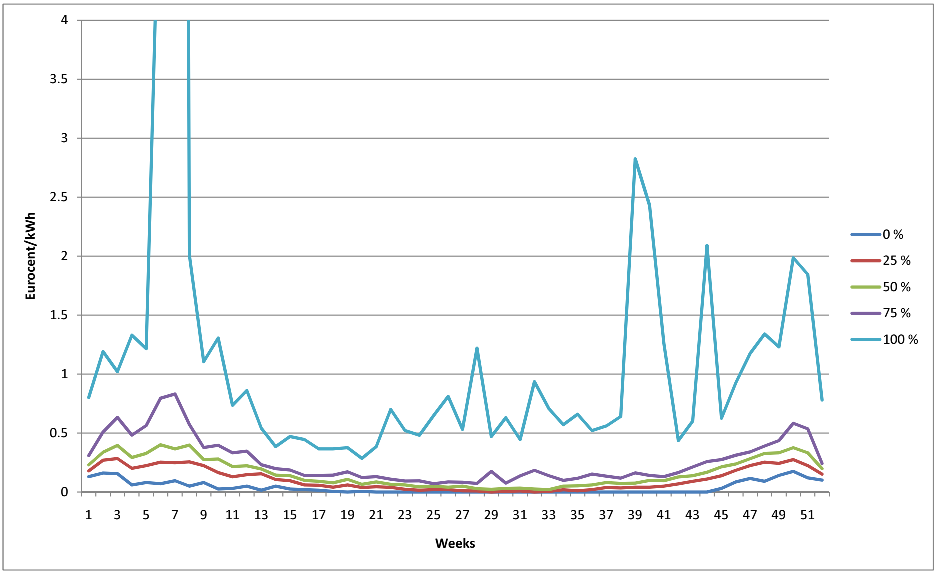

Figure 6.4.14: Price differences between the peak load periods and Low Day through the year given by percentiles.

Load shift case - uncalibrated model

It is found that load shift gives av average price reduction during the peak load periods of 0.06 cents/kWh, shown in figure 6.4.15, i.e the same average price reduction as was found in simulation B. Moreover, figure 6.4.16 shows that the maximum price reductions are much lower than in simulation B. The price changes in week 7 in 1970 in figure 6.4.17, illustrates the same phenomenon; the prices in the extreme cases are not to the same degree reduced as in simulation B. The same observation was done in the simulations where only gradual consumption adaption was implemented in the model, and it is here again verified - including gradual consumption adaption gives smaller effect of load shift in terms of reduced prices in extreme situations.

Load shift case - Calibrated model

The calibrated model for the reference case gives a very different handling of the reservoirs, which results in higher prices for certain weeks of dry years, that are not seen in the reference case. This makes it difficult to compare the price results of specific situations, as the highest prices does not occur at the same time in the two simulations. The price differences between the peak load periods and Low Day is still of interest to observe - there is now an average price difference between peak load periods and Low Day of 0.157 cent/kWh, that is the price

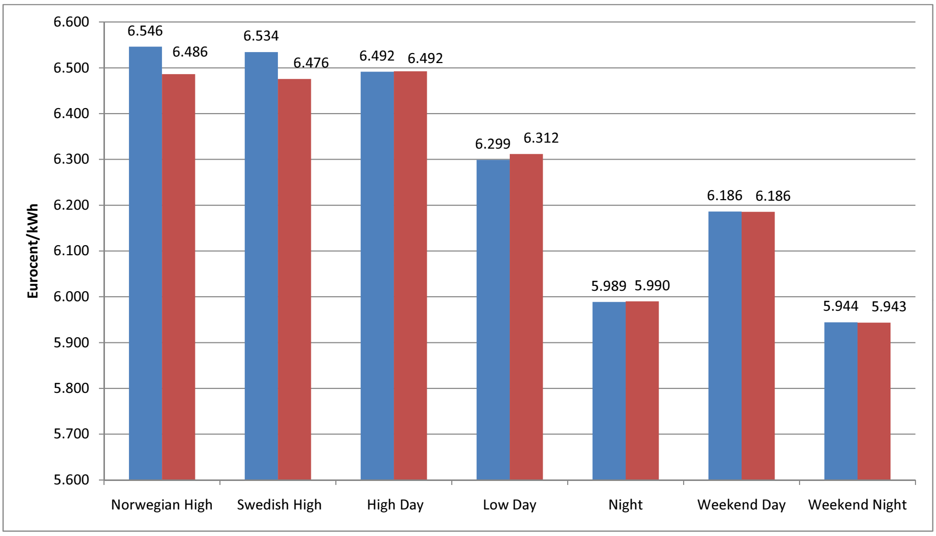

Figure 6.4.15: The average prices in each price period before and after the load shift using the uncalibrated model.

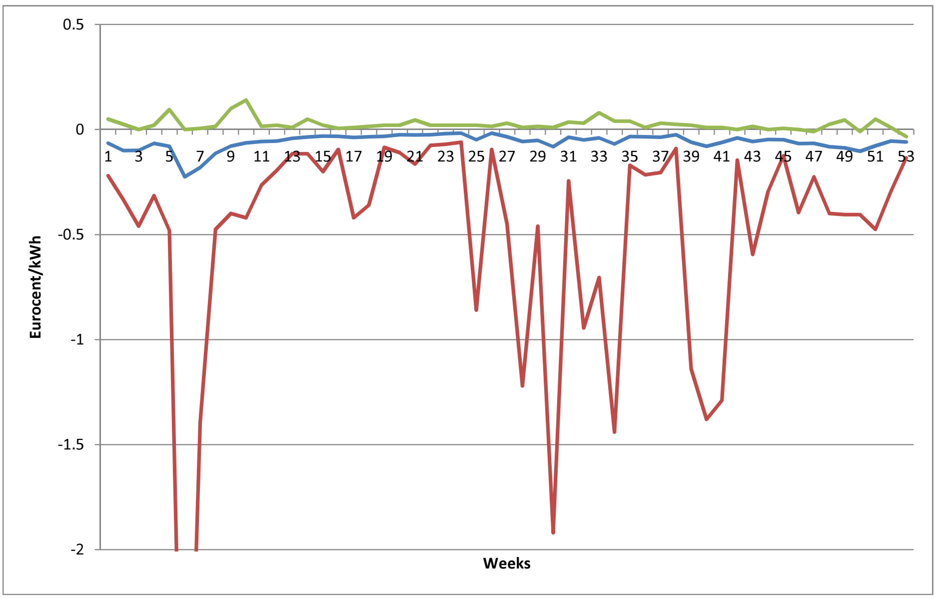

Figure 6.4.16: Price change in the peak load periods from the reference case to the load shift case, shown by maximum, average and minimum change of all inflow alternatives, using the uncalibrated model

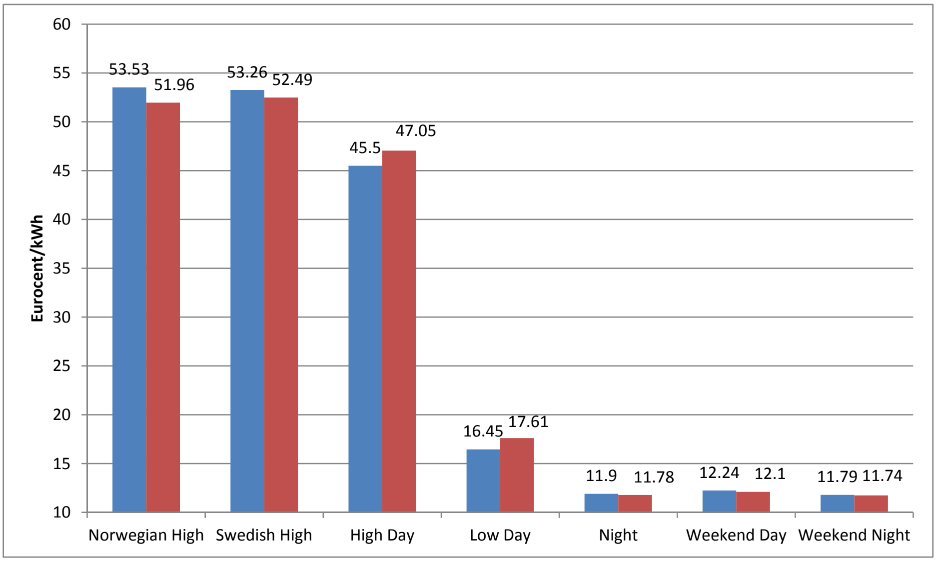

Figure 6.4.17: The average prices in all price periods before and after load shift in week 7 in 1970, using the uncalibrated model.

difference is significantly reduced from the reference case. It is however a larger price difference than obtained in simulation B.

Socio-economic surplus

The results of socio-economic surplus for the reference case and the load shift case both for the calibrated and the uncalibrated model are given in table 6.4.3. The same phenomenon as in simulation B is seen here; the uncalibrated model gives no gain of load shift. The calibrated model gives a net gain of 41.198 MEUR/year.

Table 6.4.3: Gain of load shift in social surplus

	Not calibrated	Calibrated	
Social surplus load shift case	301312	301353.4	MEUR
- Social surplus reference case	300375.85	300375.9	MEUR
-Adjustment	936.312	936.312	MEUR
Net gain	**-0.162**	**41.198**	MEUR

6.5 Simulation E - Varying the exchange prices with Germany and the Netherlands

Using financial contracts to model exchange with the continental areas excludes many effects of interactions between the markets, as the contracts only gives variations within the week by three defined price periods. These are used for all weeks of the simulation years. In order to see the impact on the results of varying prices in the Netherlands and Germany, the prices of the financial contracts with the Netherlands and Germany defined in section 5.3 are changed for three different scenarios. All the simulations are based on the improved system model where gradual consumption adaption and quadratic losses are implemented. All scenarios are simulated for both the reference case and the load shift case.

6.5.1 Scenario 1

Scenario 1 represents a simple sensitivity analysis of the prices of the import contracts for Germany and the Netherlands, involving that the prices of the off-peak and peak contracts are slightly changed. The new prices of the import contracts are:

Off-peak: 4.0 Eurocents/kWh
Peak: 8.0 Eurocents/kWh

The contract for the base load is not changed. The simulations gave that the price variation over the year for all inflow alternatives, see figure 6.5.1 is not very much changed from simulation A. The 100 percentile curve's peak is at 29.73 cent/kWh.

The average price difference between the peak load periods and Low Day has increased to 0.26 cents/kWh, and implementing a load shift now gives an average price reduction of 0.063 cent/kWh in the peak load periods. Figure 6.5.2 shows that the largest price differences between the peak load periods and Low Day are higher than in simulation A, but that the general price differences are about the same as for simulation A. The largest price difference between peak periods and Low Day is 35.725 cent/kWh. The maximum peak price reductions of all inflow alternatives are in general larger than in simulation B, see figure 6.5.4, but the largest peak price reduction is as in simulation D much lower, only 5.09 cent/kWh.

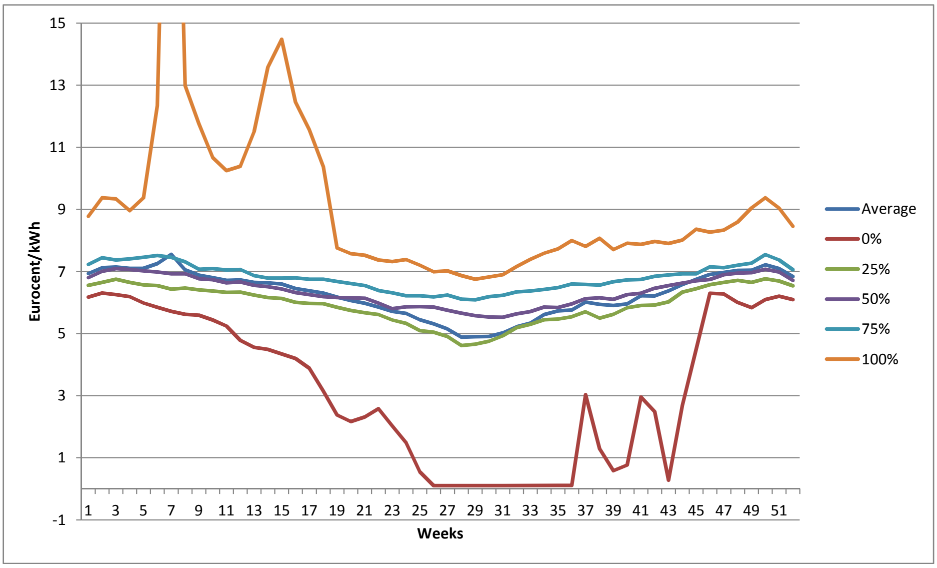

Figure 6.5.1: Variation of prices through the year in scenario 1.

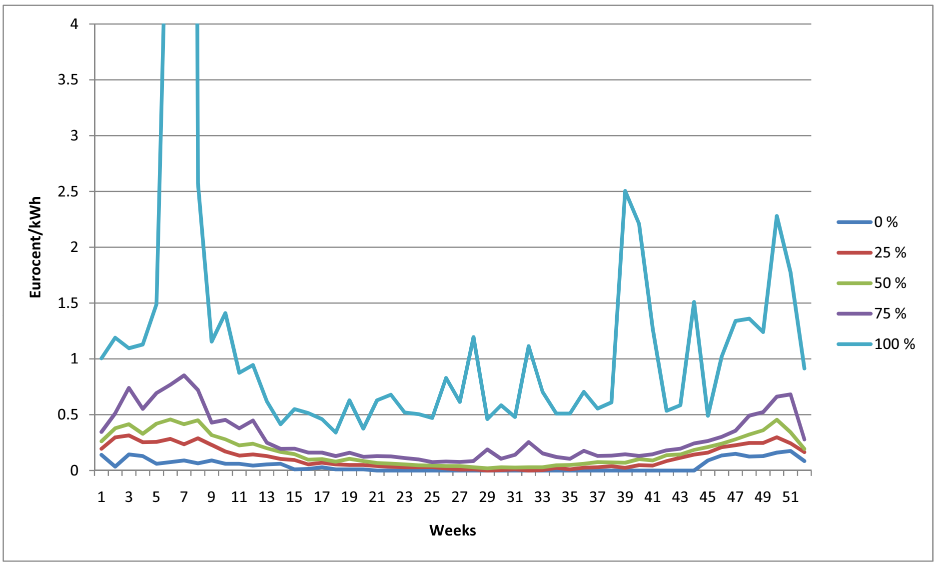

Figure 6.5.2: Price differences between the peak load periods and Low Day through the year in scenario 1 given by percentiles.

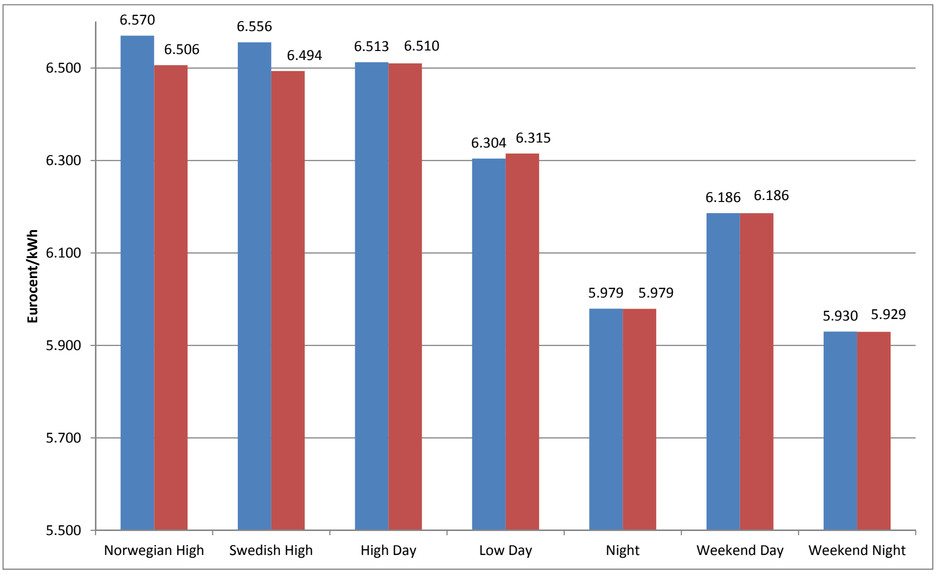

Figure 6.5.3: Comparison of the average prices in the reference case and the load shift case in all price periods in scenario 1.

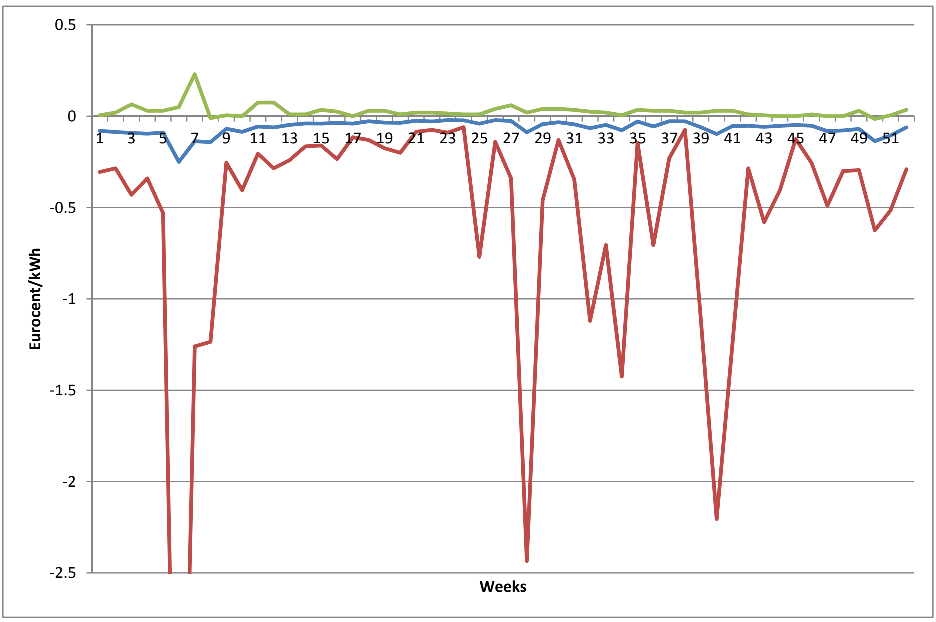

Figure 6.5.4: Price change in the peak load periods from the reference case to the load shift case in scenario 1, shown by maximum, average and minimum change of all inflow alternatives.

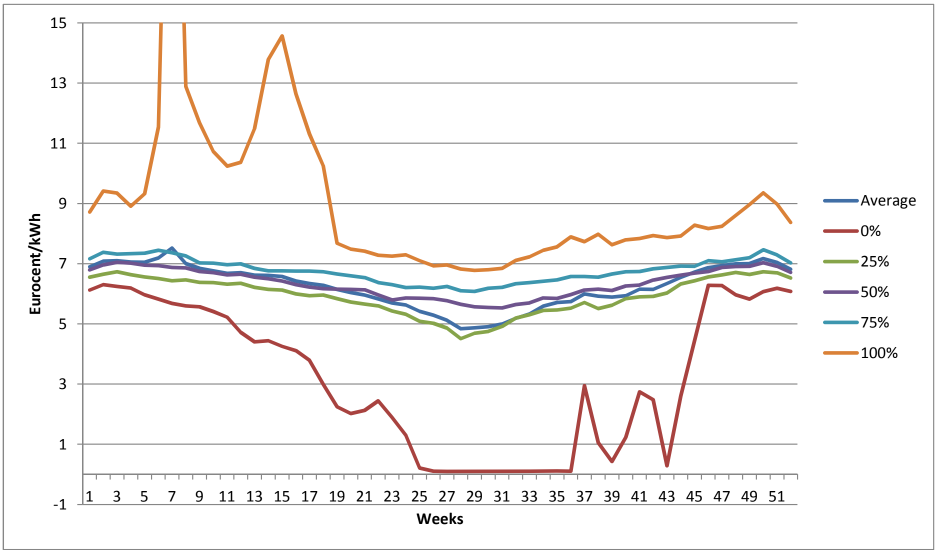

Figure 6.5.5: Variation of prices through the year in scenario 2.

6.5.2 Scenario 2

It is expected that increased wind power production in the continental areas and in Europe will for certain periods reduce the electricity prices, and for some hours reach towards 0. [20] This scenario is an attempt to see the effect of this by setting the price of the off-peak import contracts for Germany and the Netherlands to 0. Except this change, the prices of the financial contracts are kept as before.

The results show that the price variation is relatively similar to the results of simulation A, see figure 6.5.5. The peak is here at 29.52 cent/kWh. The largest price differences between the peak load periods and Low Day are somewhat higher than in simulation A, now at 36.95 cent/kWh. The general price differences are about the same.

In this case, an average price difference of 0.24 cent/kWh between the peak load periods and Low Day is found, that is, the difference is higher than in simulation D. Implementing a load shift gives in this case a peak price reduction of 0.06 cent/kWh on average basis, i.e the same reduction as found in simulation B and D.

The largest reduction in the peak load periods is at only 2.3 cents/kWh, which is even lower than the results of simulation D.

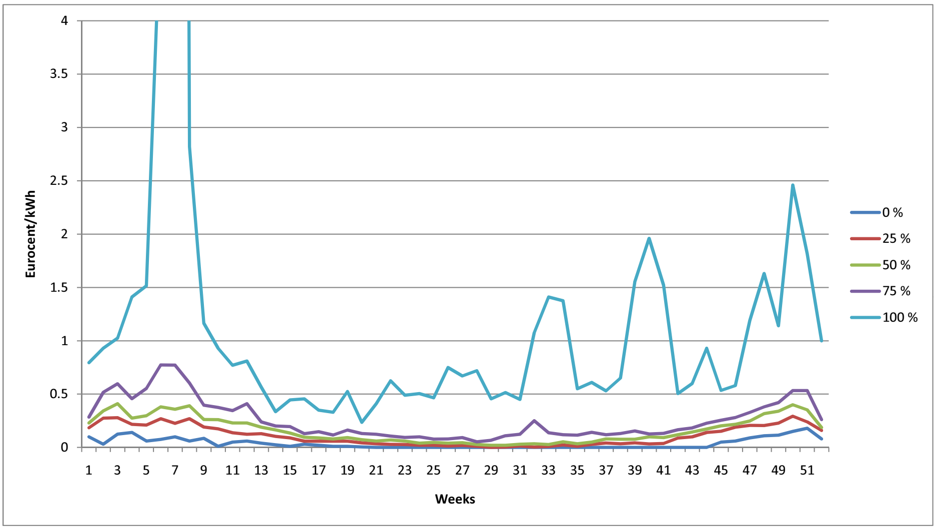

Figure 6.5.6: Price differences between the peak load periods and Low Day through the year in scenario 2 given by percentiles.

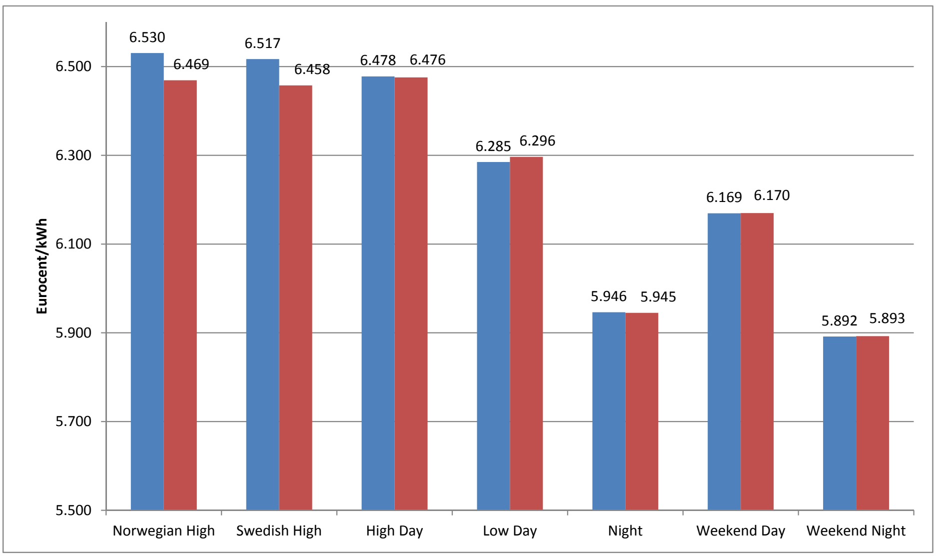

Figure 6.5.7: Comparison of the average prices in the reference case and the load shift case in scenario 2.

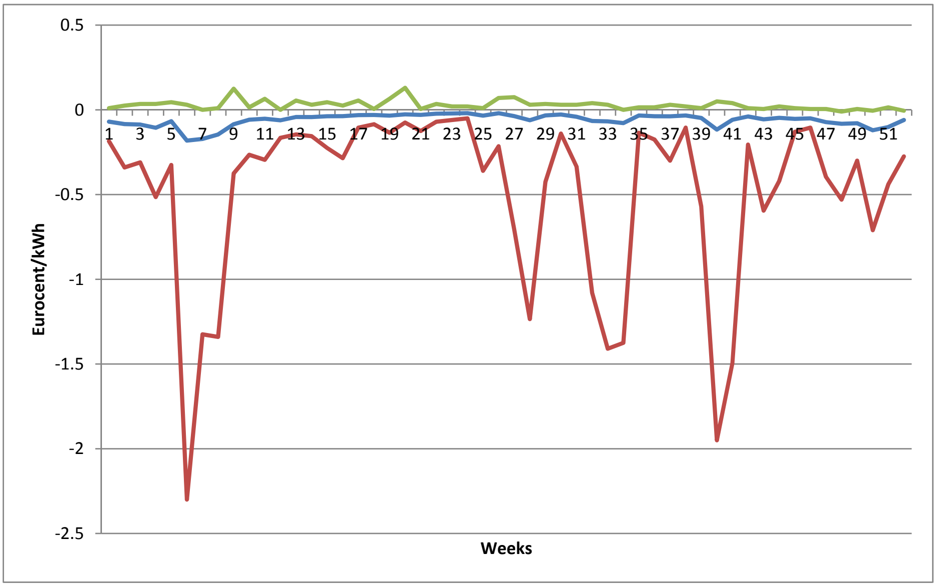

Figure 6.5.8: Price change in the peak load periods from the reference case to the load shift case in scenario 2, shown by maximum, average and minimum change of all inflow alternatives.

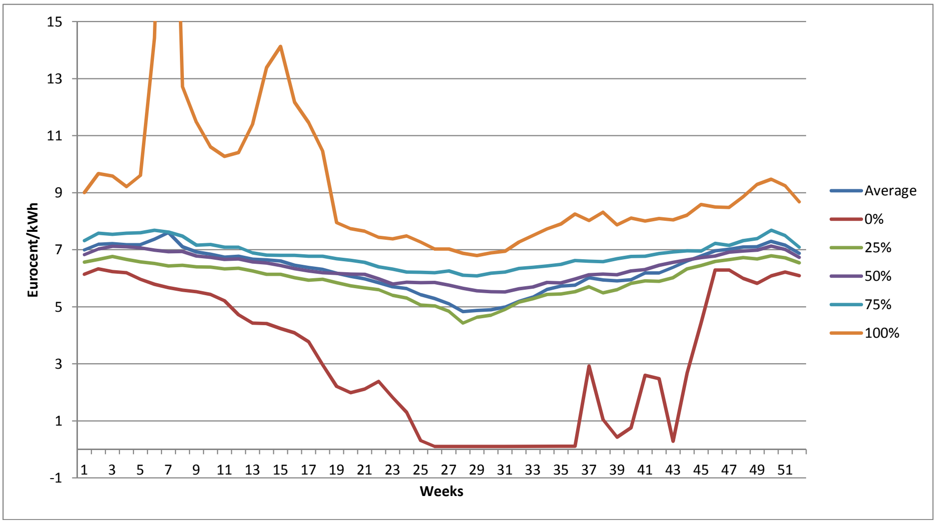

Figure 6.5.9: Variation of prices through the year in scenario 3.

6.5.3 Scenario 3

Scenario 3 models a situation where the prices in peak load periods are increased due to use of expensive gas power production instead of coal power, while the prices during off-peak periods are decreased because of increased wind production can be modeled by changing the import contract prices from Germany and the Netherlands to the following:

Off-peak: 0 cent/kWh
Peak: 9 cent/kWh

It is found that the general variation is not very different from simulation A, shown in figure 6.5.9. The peak is somewhat higher, now at 29.3 cent/kWh. The varying price differences between the peak load periods and Low Day over the is not very different from in simulation A, except that some of the largest differences are increased. This is shown in figure 6.5.10. The largest price difference is here 38.95 cent/kWh. The average price difference between peak load hours and low day is increased to 0.295 cent/kWh, which is a significant increase from simulation A. Simulations of the reference case and the load shift case show that load shift in this scenario gives large average price reduction in the peak load hours, see figure 6.5.11. Figure 6.5.12 shows that the largest price reduction in the peak load hours is now 10.48 cents/kWh, i.e a larger reduction than found in simulation D.

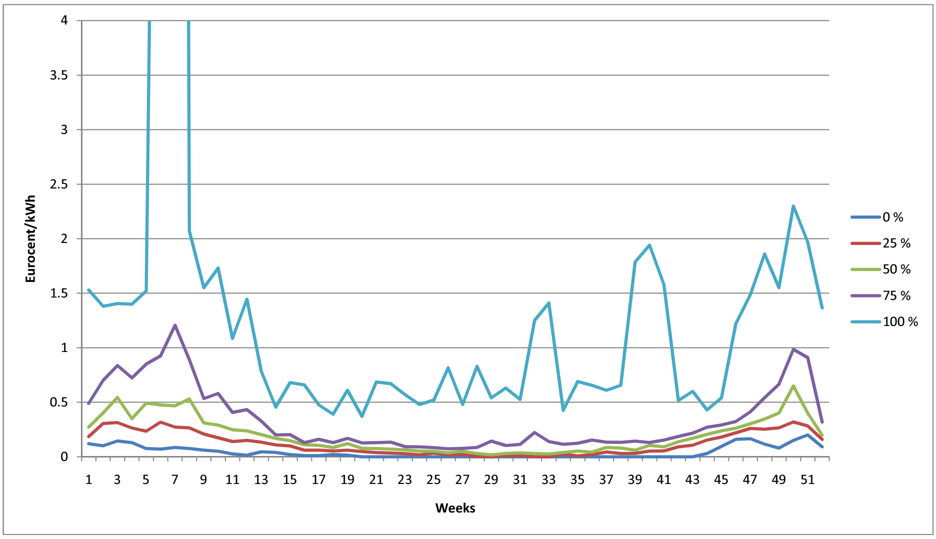

Figure 6.5.10: Price differences between the peak load periods and Low Day through the year in scenario 3 given by percentiles.

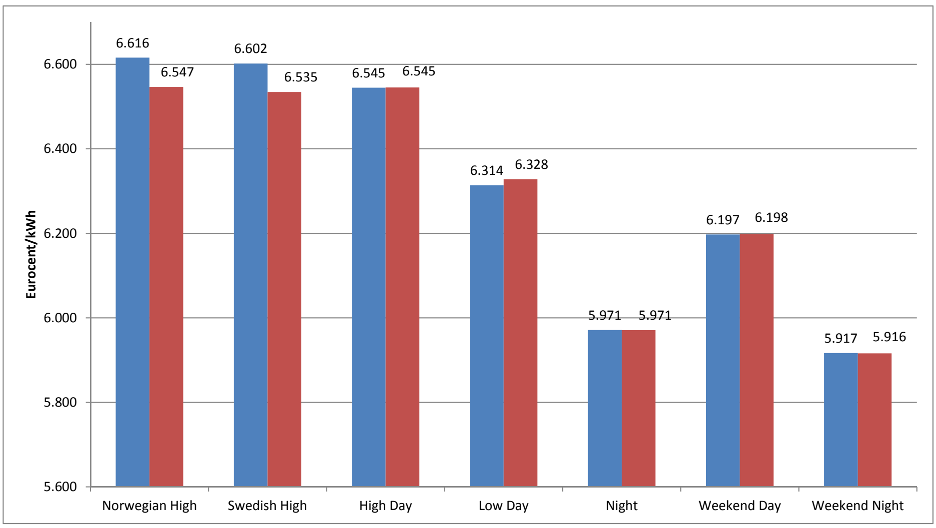

Figure 6.5.11: Comparison of the average prices in the reference case and the load shift case in scenario 3.

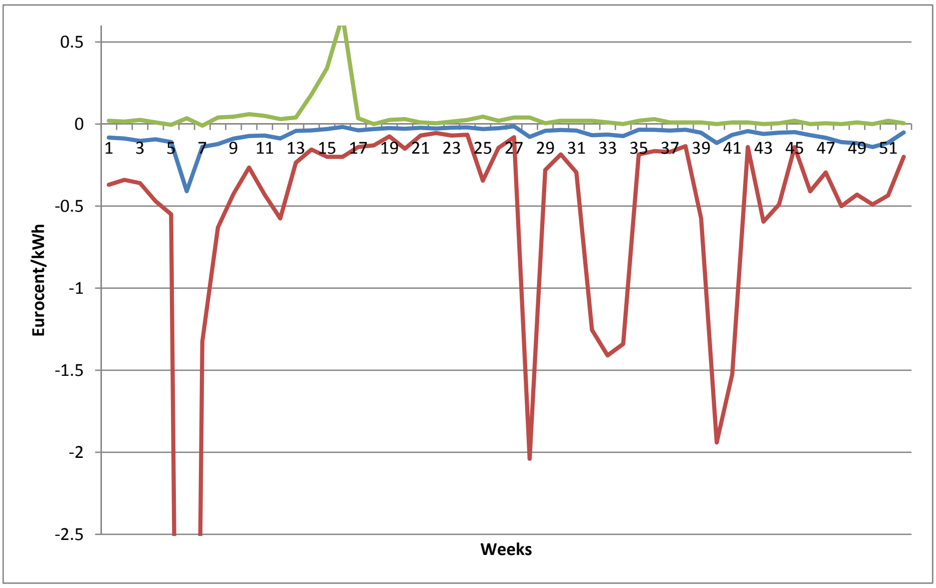

Figure 6.5.12: Price change in the peak load periods from the reference case to the load shift case in scenario 3, shown by maximum, average and minimum change of all inflow alternatives.

Chapter 7

Discussion

The simulations in this study have identified positive values of shifting load from peak load hours to low load hours in Norway. The results are varying as a consequence of implementation of different options in the EMPS model. An overview of the most important results are given in table 7.0.1, showing the average price differences between the peak load hours and Low Day and the price reduction that is achieved in peak load periods by load shift in each simulation. It is also given in the table whether the reference case and the load shift case of each simulation is based on the same water value or not. A challenge throughout this study has been to obtain realistic results for the reference case and the load shift case, which at the same time are comparable to each other. On the one hand, it is found that calibration of the model for the load shift case is necessary in order to obtain realistic results. On the other hand, calibration of the model gives a different reservoir handling, implying that new water values are calculated. The price level in each simulation is thus somewhat changed, which makes the comparisons difficult. This is especially the case for dry years, where the price levels are very sensitive to the reservoir handling. A different handling of the reservoirs may lead to very high prices for weeks where high prices did not occur in previous simulations. Simulations with uncalibrated models therefor give a better indication of changes in prices, while it for calculation of social surplus is necessary to perform a calibration to get realistic results.

Table 7.0.1: Comparison of key results, given in Eurocent/kWh

Simulation	**Average price diff. peak/LD in ref. case**	**Average red. of peak load price**	**Largest price red.**	**Same water value calc. used in ref/LS case**
B	0.211	0.063	33.02	No
C	0.217	0.048	8.46	No
D	0.241	0.059	3.79	Yes
E				
Scenario 1	0.259	0.063	5.09	Yes
Scenario 2	0.239	0.060	2.30	Yes
Scenario 3	0.295	0.070	10.48	Yes

7.1 Simulation A

The prices obtained by the simulations have shown that the dataset gives little variation of prices and that few cases of very high prices are represented. Only one extreme situation with high prices was identified, i.e where the prices exceeded 10 eurocent/kWh. Except for this case, the prices are mainly varying in the range of 5-7 cent/kWh. It is also a weakness that the maximum power consumption in Norway is modeled somewhat too low, showing a peak of below 23 000 MW, while the maximum consumption in the power system has reached close to 24 000 MW. This probably contributes to give somewhat low price peaks, which may result in smaller price differences over the day. Still it is shown that the average price difference between the peak load periods and Low Day is consistent with the market prices in Nordpool.

The simulations showed larger price differences than found in the work of Doorman and Wolfgang [6]. One of their conclusions was that poor representation of variation of wind power production was reason to the low price differences within the day. As the wind data is improved in the model used on this study, it is likely that this has increased the price differences and thus the effect of a load shift.

The results found by this study is to a large extent limited by the variation of prices in the dataset. An important, but challenging question is therefore to what extent this kind of study is able to set a value of a load shift in the Norwegian power system, as the results found are given only by the price variations of the dataset. On the other hand, setting a standard for what normal variations in the market are is difficult. This study therefore gives a good indication of the load control, based on the conditions of the dataset that is used. The results may also be used to indicate the effect load shift in specific situations.

7.2 Simulation B

In simulation B it turned out that calibrating the model was a decisive factor for the results. When the simulation was performed without calibrating the model, the difference in socio-economic surplus was slightly negative changed from the reference case. The fact that calibration of the model is necessary for small changes such as those that are made here is surprising, and gives reason to believe that simulations without recalibration in many cases may provide uncertain results. Calibration is however very time consuming, and in these kinds of studies it is not enough time to perform calibrations for all simulations.

The results obtained by the calibrated model showed an average price reduction of the prices in the peak load periods of 0.06 cent/kWh, which is not a large change. What is more important is the effect on the prices when demand is close to the capacity limit of the power system. It was found that the effect in these cases is large; in the extreme situation in week 7 in 1970, the peak prices were reduced from above 50 cent/kWh to below 20 cent/kWh.

7.3 Simulation C

Including variation of wind power production within the week increased the average price difference between the peak load periods and Low Day slightly. The impact of a load shift on the peak load prices was however smaller in this case, which is somewhat unexpected. The effect of a load shift is also much smaller in extreme situations, although there is still existing a large price difference between the peak load periods and Low Day. A reason can be that the variation of wind power production between the periods is now more significant for the price level than the variation of load is. A reduction of load in a certain periods gives thus a smaller impact on the prices. This simulation also includes start-up costs of thermal power, which may affect the prices. The impact should however not be large, as there is little thermal power modeled in the Nordic system.

It was intended to include variation of wind within the week in simulation D and E as well, but unfortunately there were problems with combining the functions used in simulation D. The results in simulations C still indicates that it is likely that a lower effect of load shift is gained than the results in simulation B, D and E show.

7.4 Simulation D

7.4.1 Quadratic losses

Implementing quadratic losses in the model required that a coefficient of maximum losses for each connection had to be assumed, otherwise the function gave overall very low losses and thus low prices. The coefficient was assumed to be equal to the loss coefficient already defined in the model multiplied by a factor of 5, which gave that the total losses of the system were close to the total losses found when using linear losses. Using quadratic losses showed larger price differences between the peak load periods and Low Day than in simulation A. As the function is based on little experience and testing, the results involves some uncertainty.

7.4.2 Gradual consumption adaption

Realistic modeling of flexible consumption is difficult, as there are many complex elements connected to it. Finding a reasonable assumption for a parameter of gradual consumption adaption thus proved to be challenging. A perfect assumption would require large studies of the behavior of the various consumption units, and at the same time it would be necessary to go into detail of the modeling of the different units. As it in this study has not been done detailed analyses of price elasticity of flexible demand, the assumptions are based on the effect that is observed in the simulations, as well as qualitatively considerations of flexible demand's market adaption.

The analyses of the effect by implementing gradual consumption adaption showed that the function has little effect on demand in this model, due to two main reasons: (1.) that one large unit within flexible consumption in Østland is modeled at a very high disconnection price (2.) that the dataset gives few extreme cases; the prices rarely exceeds the disconnection price of the largest unit within flexible demand. It is thus difficult to say anything about the effect of implementing gradual consumption adaption on general basis. It is however seen that in extreme situations, a varying size of inertial parameter does affect the level of flexible consumption and the maximum prices. Since the value of load shift as well is given by these situations, the value is affected by the implementation of this function.

Gradual consumption adaption did not result in the larger price differences within the day that it was expected to. The reason is that the same change in consumption level is present for both the peak load periods and the low load period.

Including gradual consumption adaption in the simulations showed that the slower the adaption to the market variation is, the smaller is the value achieved by a load shift. The reason is that the higher the inertial parameter is, the smaller is the volume that is disconnected at this level. This results in no large effect of a load shift in short periods of high prices. It is also possible that the effects of gradual consumption adaption and a load shift counteract each other. When load is moved away from a period, the price cross is at a lower point than it would originally be. If the market adaption of flexible demand is slow, this may result in that less flexible consumption is disconnected.

It is important to emphasize that the disconnection volume, and thus the total consumption level will always depend on many factors; the price level, the length of the time period of high prices, the disconnection price of flexible consumption and the volumes modeled as flexible consumption. In the dataset used in these simulations, there was just one extreme situation represented, which lasted for not more than a week. A dataset where periods of high prices lasted longer would probably result in larger disconnection volumes also with slower consumption adaption, which probably would give a larger effect of load shift.

The calibrated model in the load shift case where both quadratic losses and gradual consumption adaption is included showed somewhat different price results than seen in other simulations. Very high prices occurred for certain weeks, where it is not observed before. That is, the prices were clearly affected by differently reservoir handling, which makes the reference case and load shift case difficult to compare. The results however showed a net increase in socio-economic surplus of 41.198 EUR per year between the two cases. This number is uncertain due to the calibration, but it indicates a positive value of shifting load.

7.5 Simulation E

Using financial contracts to model connections with the continental areas simplifies the computations of the program, but at the same time it excludes considerations of dynamic effects between the power markets. The consequences of varying prices in the German and Dutch market were investigated by three simulations, showing that variations in these markets affect the prices in Østland. Larger price differences on the continental areas increases the price differences between peak load periods and Low Day in Østland, which gives a larger value of a load shift as well. With lower prices due to increased wind power production and high prices due to utilization of gas power plants instead of coal, the value of a load shift increased; the peak price reductions were larger than in earlier simulations, both on average basis and in extreme situations.

7.6 Modeling reserves

Reserve capacity is in this study modeled so that there is an amount of capacity kept unavailable in the power system, and never able to serve demand. This modeling is unrealistic especially regarding hydro power capacity, as these reserves in the model are unavailable to serve demand even in extreme situations. The modeling may affect the results by further increasing the prices in extreme situations.

Chapter 8

Conclusion

This study has found by running simulations in the EMPS model that there is a positive value in shifting 600 MW of consumption from two peak load hours to low load hours in Norway. The value is identified in terms of increased socio-economic surplus for Norway and reduced prices during peak load hours in the area Østland both on average basis and in extreme situations of very high prices. The simulations are performed using the existing model of the Nordic system and by implementing functions that improves the model. The improving functions are gradual consumption adaption and quadratic instead of flexible losses. A simulation where variation of wind power production within the week is included is additionally run. Effects of varying exchange prices in the continental areas are investigated by changing the prices of the modeled financial contracts.

8.1 Socio-economic surplus

Simulations using the original model has shown that the increase in socio-economic surplus by shifting load is 20.208 MEUR per year, while using the improved model where quadratic losses and gradual consumption adaption is implemented gives an increase in socio-economic surplus of 41.198 MEUR per year. The results regarding socio-economic surplus involves some uncertainty, as the simulations of the two cases that are compared, i.e the reference case and the load shift case, did not use the same calibration factors. There is however a clear positive value of load shift present. Simulations of the two cases when using the same calibration factors gave a negative value of load shift, meaning that a calibration of the model is necessary after shifting load in order to obtain optimal reservoir handling.

8.2 Impacts on prices

Implementing a load shift gave reduced average prices in the peak load hours and increased average prices in the low load hours. The average peak price reduction is for nearly all the simulations around 0.06 cent/kWh - both with and without including quadratic losses and gradual consumption adaption.

The effect of a load shift is to a large extent decided by the price differences between the periods that load is shifted between. Implementation of the new functionalities quadratic losses and gradual consumption adaption in the model did not change the overall price variations significantly, but changes in the peak prices were recognized. Using quadratic instead of linear losses in the simulations increased the average price differences between the peak load periods and Low Day, while implementing gradual consumption adaption did not result in larger price differences between the periods. Including variation of wind power production within the week gave slightly larger price differences between the periods.

Including variation of wind production within the week showed a smaller effect of load shift in terms of average reduced peak load prices than in the other simulations, showing an average peak load price reduction of 0.048 cent/kWh. This indicates that the effect of a load shift on the prices is in reality likely to be somewhat smaller than found in other simulations, where variation of wind power production within the week is not included.

The original model showed that a load shift gives large price reductions in extreme situations where the demand is close to the capacity limit of the power system. The price in the peak load periods were in one situation reduced by 33.02 cent/kWh. With the improved model, this large price reduction was not present. The reason is that when flexible demand slowly adapt to the market, the total consumption volume is higher, and the load shift is not enough to give considerable reductions of prices. The reduction of peak load prices due to load shift when using the improved model was only of 3.79 cent/kWh. The situation represented here is a week where the prices increase rapidly and stays high for about a week. A period of longer lasting prices would probably give a larger disconnection volume within flexible demand, which could give large price reduction also with this function implemented.

Varying the exchange prices with the continental areas showed that variations in these markets do affect the price differences between the periods in Østland. The value of a load shift was in these cases increased as well. A scenario were simulated where the prices in the Netherlands and Germany during off-peak are 0 due to increased wind power production, and the prices during peak load periods are increased due to use of gas power instead of coal. This gave that the average price difference was significantly increased, and an average peak price reduction of 0.07 cent/kWh was identified. The price reduction in an extreme situation was now 10.48 cent/kWh.

The results found in this simulation are based on a dataset where few and small price variations are represented. Whether this is representative for the Norwegian power system or not is difficult to say, as the value will differ form year to year, with regards to the variations occurring in the power system. It is shown in this study that there is a positive value of load shift with the given price differences between the periods and the represented extreme situations of high prices. This indicates that in a year of similar price differences, a load shift provides benefits for the Norwegian power system. In cases where few load peaks occur, the value of a load shift is more uncertain.

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Appendix A

Method

A.1 Allocation of the load shift

Table A.1.1 shows the exact numbers of how the volume of the load shift was allocated among the areas in Norway in the load shift case.

Table A.1.1: Overview of how the load shift is distributed among the areas in Norway.

Area name	**Fixed demand [GWh/year]**	**Share of total demand**	**Load Reduction NH and SH [MW]**	**Load Increase LD [GWh/week]**
Glomma	0	0.00	0	0.0
Ostland	34878	0.40	237.9	2.4
Sorost	8515	0.10	58.1	0.6
Halling	743	0.01	5.1	0.1
Telemark	1352	0.02	9.2	0.1
Sorland	7019	0.08	47.9	0.5
Vestsyd	8999	0.10	61.4	0.6
Vestmidt	1778	0.02	12.1	0.1
Midt	15054	0.17	102.7	1.0
Helge	1691	0.02	11.5	0.1
Troms	5976	0.07	40.8	0.4
Finnmark	1964	0.02	13.4	0.1
	168969	1.00	600	6

A.2 Adjustment of social surplus

Socio-economic surplus corresponds to the area between the demand curve and the supply curve, i.e the consumer surplus plus the producer surplus.

When implementing a load shift from Norwegian High and Swedish High to Low Day, the socio-economic will increase during Low Day since the demand is higher for all prices. The socio-economic surplus will decrease for the peak load periods, as demand is reduced.

The load shift is in this report implemented by adding a new generation unit during Norwegian High and Swedish High that produces the reallocated volume no matter how low the market price gets, and adding a consumption unit during Low Day that consumes no matter how high the market price gets. This way, the supply curve is shifted in the peak load period instead of shifting the consumption curve. The effect on the prices is the same, but the socio-economic surplus is not reduced during the peak load periods. Due to this, an adjustment for the socio-economic surplus has to be adjusted.

The adjustment is calculated as described in [6]:

> We start by considering how much the socio-economic surplus changes if we increase demand and supply within the same period, cf. figure A.2.1. This is analogous to what we have done except that we have increased demand in one period and supply in another period.
>
> Before the change in demand and supply the dotted line was the vertical axis, and the initial socio-economic surplus is marked "Initial surplus". The solid extensions of the demand- and supply curves on the left of the dotted line show the addition to the demand and supply, and the additional socio-economic surplus is marked "Additional surplus". Thus, if we reallocate demand from and to the same period with our methodology, the socio-economic surplus increases with the marginal value of the additional times the reallocated quantity. This amount must therefore be subtracted from the new socio-economic surplus. Now we will show that the needed adjustment is the same when the demand and supply is adjusted in two different periods.
>
> First we consider what the socio-economic surplus would be in the two periods if we had implemented the reallocation of demand by positive and negative shifts respectively in the demand curves for the low load and peak load periods. Thereafter we will show what the socio-economic surplus will be in the two periods when we implement the reduced remand in the peak load period as an increased supply. This identifies the required adjustment in the socio-economic surplus when the latter method is used instead of the former.
>
> Figure A.2.2 shows the socio-economic surplus after the demand has

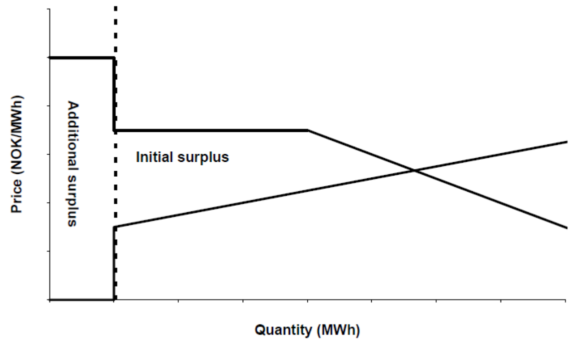

Figure A.2.1: Increased socio-economic surplus for an additional demand unit with marginal value above rationing cost and a corresponding increase in supply at zero costs. [6]

been reallocated by shifts in the demand curves. The size of the shift is marked with an Δ and the size of Δ is the same in all figures. The solid lines show the initial situation, while the dotted lines show the new demand curves when demand is reallocated from the peak load period to the low load period. The socio-economic surplus after reallocation of demand is given by the area $A + B + C$.

Figure A.2.3 shows the socio-economic surplus in the same two periods when the reduced demand in the peak load period is implemented as increased supply at zero costs and the increased demand in the low load periods is implemented by including additional demand that has a marginal value above rationing costs (rationing costs are given by the flat segment of the demand curves). The solid lines show the initial situation while the dotted lines show how demand and supply change in the two periods. Note that the right shift for the supply curve in figure A.2.3a (the horizontal distance between the solid and the dotted curve given byΔ) is the same as the left shift for the demand curve in figure A.2.2a and the right shifts for the demand curves in figure A.2.2b and figure A.2.3b.

The total socio-economic surplus in figure A.2.3 after demand has been reallocated with our methodology is $D+E+F+G+H+I+J$. If the thick gray line had been the vertical axis in figure A.2.3a, the demand curve had shifted by the reallocated amount compared to

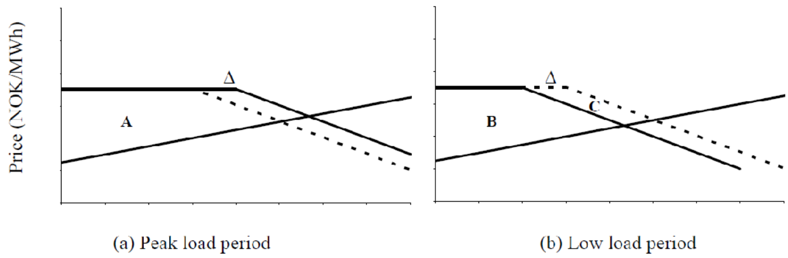

Figure A.2.2: Increased socio-economic surplus after reallocating demand by shifting the demand curve. [6]

> the initial situation. Thus, the demand curve seen from the gray vertical line towards the right is identical to the dotted demand curve in figure A.2.2a. Moreover, the dotted supply curve in figure A.2.3a is identical to the initial supply curve used in figure A.2.2a seen from the gray vertical line towards the right. Thus, seen from the gray line towards the right, the solutions after the changes are identical in figure A.2.3a and figure A.2.2a. It follows that $A = E + G$. In addition it is straightforward to see that $B = H$ and $C = I$. When we substitute this into the expression for socio-economic surplus for figure A.2.3a, we get $A + B + C + D + F + J$. The difference in the socio-economic surplus in figure A.2.2 and figure A.2.3 is therefore $D + F + J$, which is the area marked as "Additional surplus" in figure A.2.1.

The adjustment amount is given by equation (4.4.1), which for this case gives

$$6000MWh/week \cdot 52weeks \cdot 300.1Eurocent/kWh = 936.312MEUR/year$$

where $300.1Eurocents/kWh$ is the price of the additional consumption unit, which is set slightly above the rationing costs $300Eurocents/kWh$.

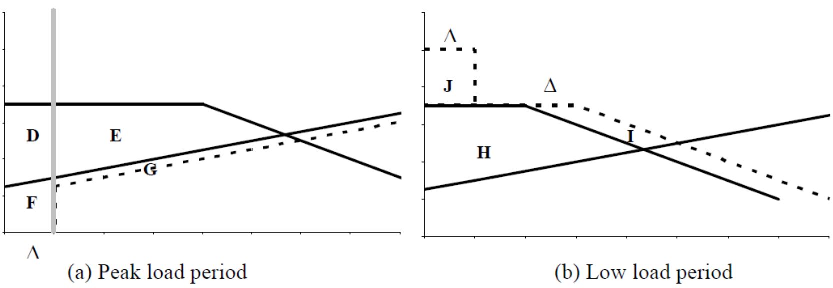

Figure A.2.3: Increased socio-economic surplus after reallocating demand with the described mehodology. [6]

Appendix B

Input Data

B.1 Modeling reserves

B.1.1 Reduced hydro power capacities in Norway

Table B.1.1 shows the reservoirs of which maximum capacity was reduced in order to serve for primary and secondary reserves in Norway and the corresponding reduction sizes.

Table B.1.1: Reduced maximum capacities for reserves

Area Name	Reservoir name(s)	Max cap. reduced by [MW]
Nor-Ostland	Tokke	150
Nor-Sorland	Tonstad	260
Nor-Vestsyd	SANDSA+LAUV	340
Nor-Vestmidt	REMBESDALSVA	200
Nor-Helge	Akersvatn	150
		1100

B.1.2 Reduced thermal power in Sweden, Denmark and Finland

Table B.1.2, B.1.3 and B.1.4 show the power plants and by how much maximum capacities were reduced.

Table B.1.2: Reduced maximum capacities of oil and gas power plants in Sweden

Area Name	**Plower Plant No**	**Reduced by**
Sver-Syd	14	270 MW
	15	270 MW
	16	270 MW
	17	140 MW
Sver-MOst	20	140 MW
Sver-Mvest	14	100 MW

Table B.1.3: Reduced capacities of thermal power in Finland

Power plant no	**Reduced by**
32	50 MW
34	40 MW
35	100 MW
37	180 MW
38	90 MW
39	150 MW
40	130 MW
41	100 MW
In total	840 MW

Table B.1.4: Reduced capacities of thermal power in Denmark

Area name	**Power Plant no**	**Reduced by**
Danm-Vest	16	150 MW
	18	60 MW
	19	100 MW
Danm-Ost	17	160 MW
	20	30 MW
	21	50 MW
	22	70 MW
	23	70 MW
	24	30 MW

B.2 Power flow on the connections from the Nordic system to Germany

The power flow between Denmark East and Germany during Low Day is shown in figure B.2.1 The average flow goes towards Denmark during the winter and the other way during the summer. Denmark experiences export during a wet year and import during a dry year.

Figure B.2.2 shows the power flow between Denmark East and Germany during Norwegian High. The average flow goes mainly towards Germany, except some weeks in the summer. Denmark exports during a wet year and imports during a dry year, except during a few weeks in the summer.

Figure B.2.3 shows the power flow between Denmark East and Germany during the night. The flow goes mainly towards Denmark, except some weeks during the summer in wet years.

The average power flow between Denmark West and Germany during Low Day is given in figure B.2.4. There is an average export to Germany, but in drier years, Denmark is importer.

Figure B.2.5 shows the power flow between Denmark West and Germany during Norwegian High. Denmark always exports, except in winter and early spring in dry years.

The power flow between Denmark West and Germany during the night is shown in figure B.2.6. Denmark mainly imports, except in very wet years.

Figure B.2.7 shows the power flow between Sweden and Germany during Low Day. In average, Sweden imports during the winter and exports during the summer. During the wet years, the flow goes from Sweden to Germany during the whole year, while it is the other way around during dry years.

Figure B.2.8 shows the power flow between Sweden and Germany during Norwegian High. Sweden exports during the summer and imports during the winter. In reality, there would probably be some more export from Sweden during the winter as well, but the result is satisfactory good.

The power flow between Sweden and Germany during the night, shown in figure B.2.9, results in import to Sweden during the whole year, except for during the summer in a wet year.

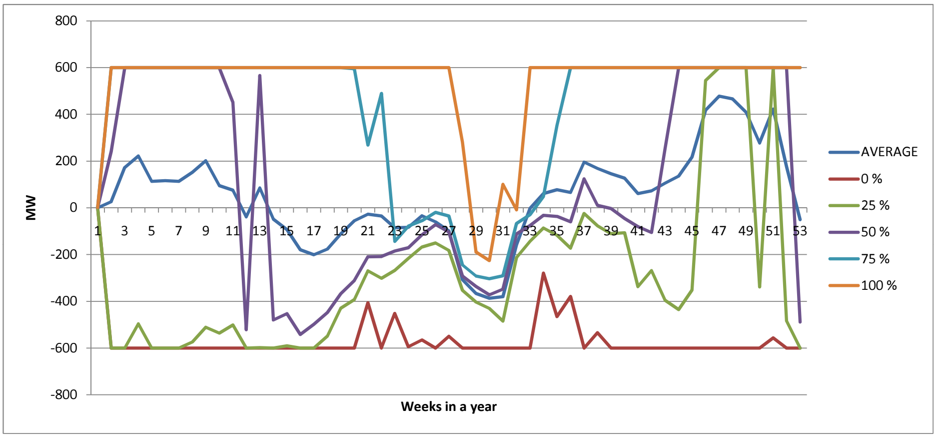

Figure B.2.1: Average power flow between Denmark East and Germany during Low Day.

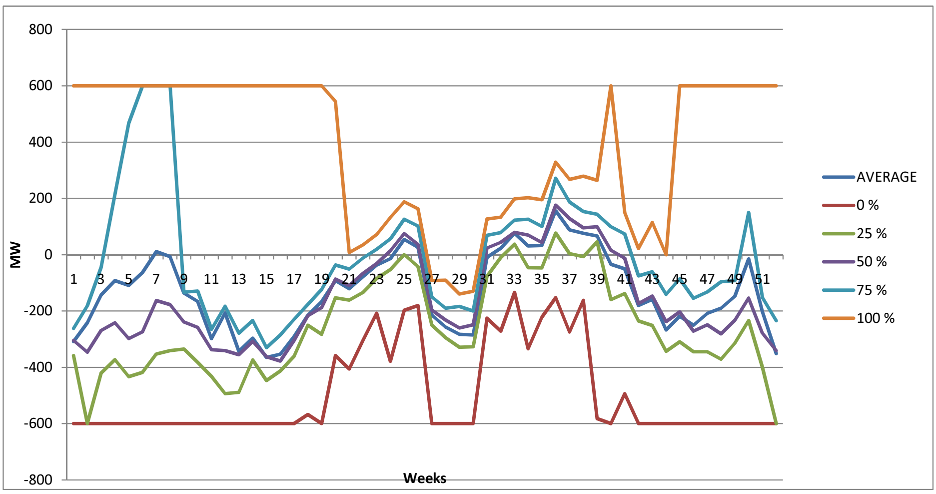

Figure B.2.2: Average power flow between Denmark East and Germany during Norwegian High.

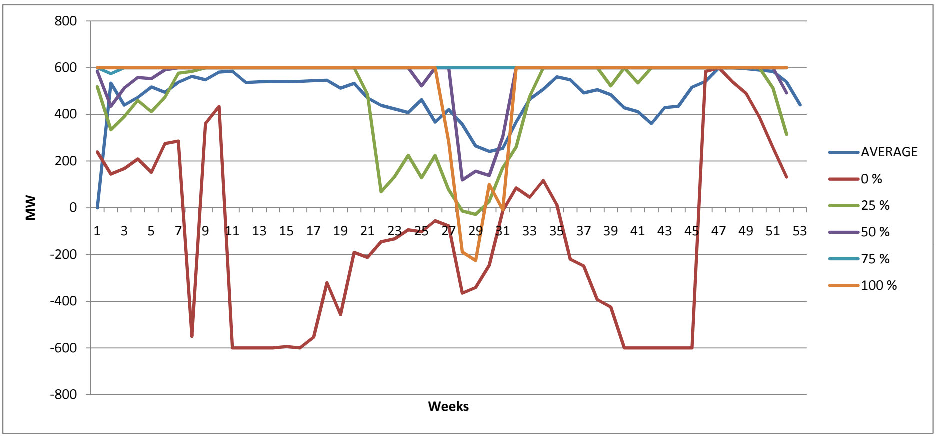

Figure B.2.3: Average power flow between Denmark East and Germany during the night.

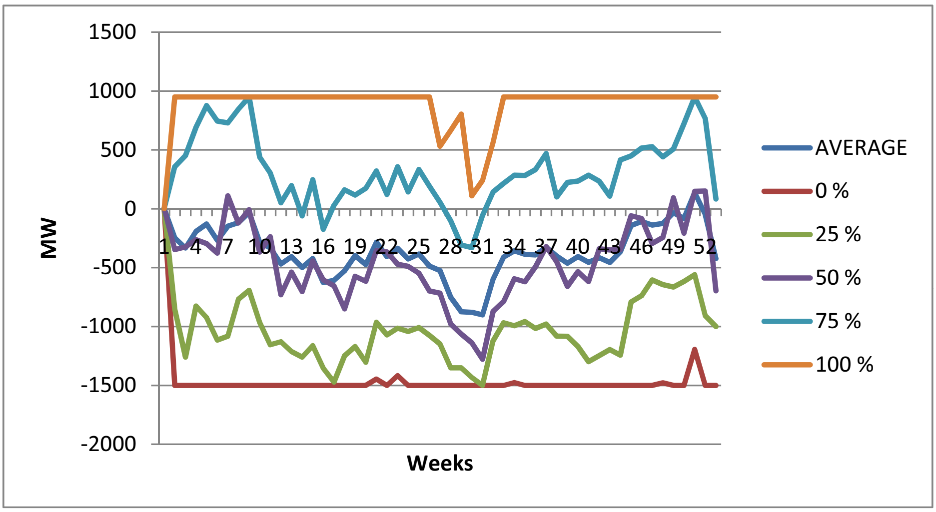

Figure B.2.4: Average power flow between Denmark West and Germany during Low Day.

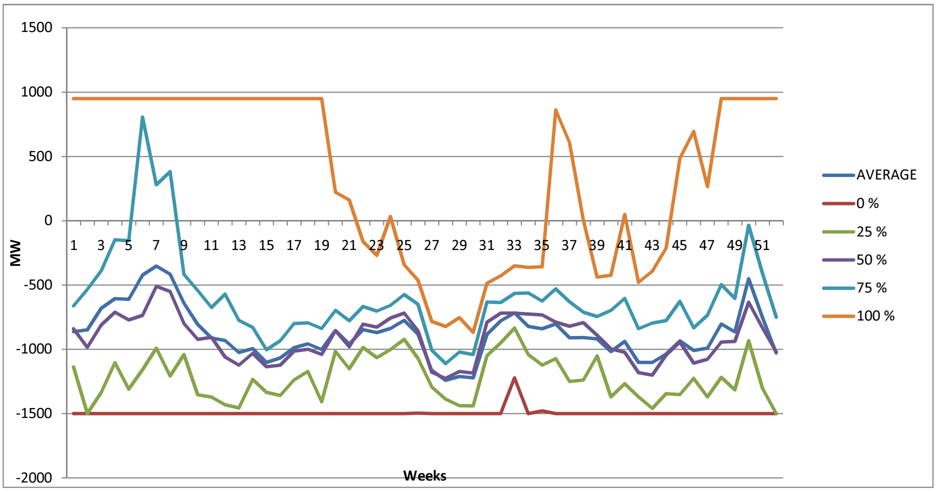

Figure B.2.5: Average power flow between Denmark West and Germany during Norwegian High.

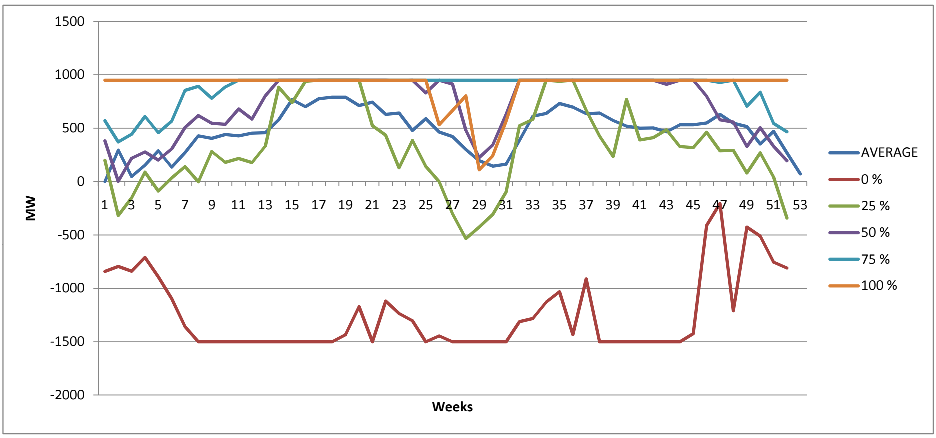

Figure B.2.6: Average power flow between Denmark West and Germany during the night.

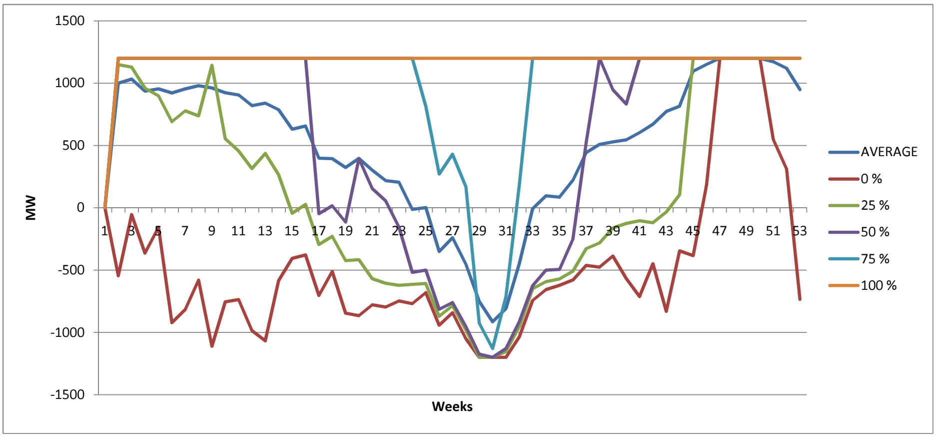

Figure B.2.7: Average power flow between Sweden and Germany during Low Day.

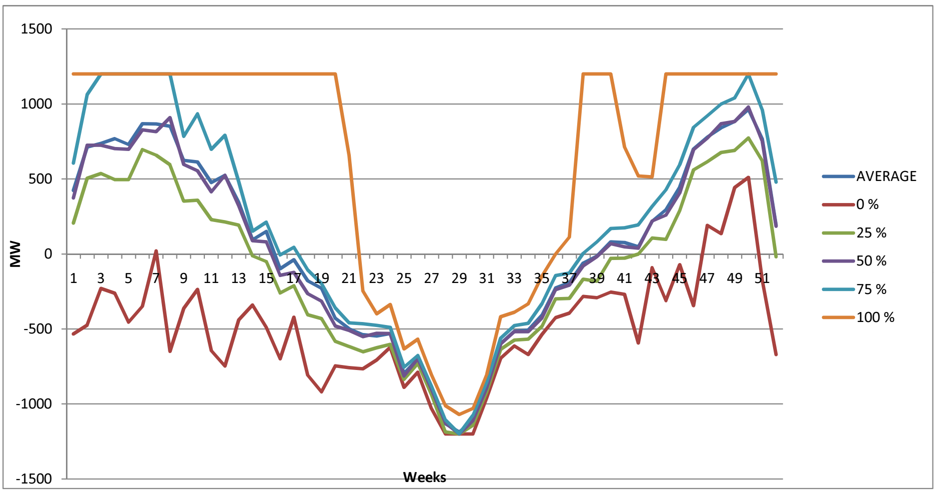

Figure B.2.8: Average power flow between Sweden and Germany during Norwegian High.

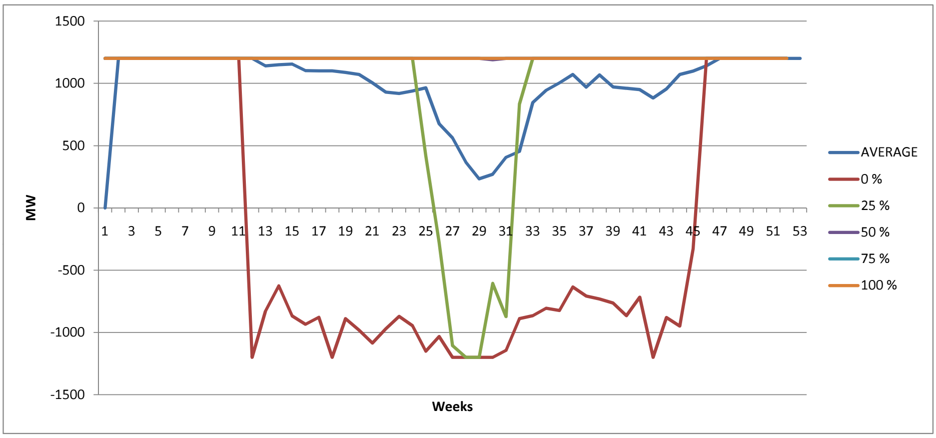

Figure B.2.9: Average power flow between Sweden and Germany during the night.

Appendix C

Simulations

C.1 Results from uncalibrated model in simulation B

Table C.1.1: Difference in social surplus from simulation A to simulation B, using an uncalibrated model in the load shift case.

Social surplus simulation B	301295	MEUR
- Social surplus simulation A	300358.8	MEUR
=	936.26	MEUR
-Adjustment	936.312	MEUR
Net gain	**-0.052**	**MEUR**

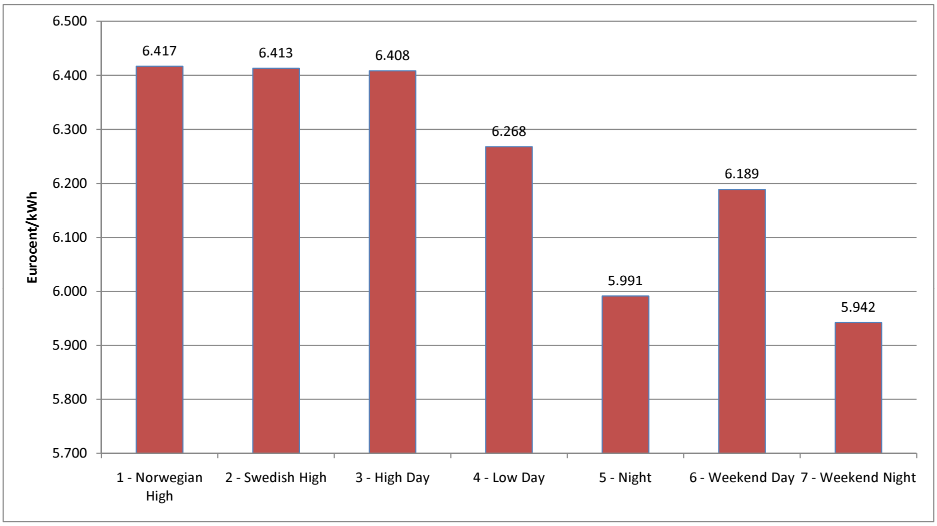

Figure C.1.1: Average prices in the load shift case in simulation B using an uncalibrated model in the load shift case.

C.2 Modification of loss coefficients

The theory describing implementation of quadratic losses in 3.6 required some modifications and assumptions that are described below.

Equation (3.6.1) described the losses $Loss_i$ in each segment as

$$Loss_i = (\frac{P_i}{P_{Max}})^2 \cdot Loss_{Max}$$

$Loss_{Max}$ is however not defined in the file MASKENETT.DATA, which only has the option to define the loss coefficient for linear losses. When implementing quadratic losses, the loss coefficient for linear losses is automatically used as $Loss_{Max}$. This will give the expected effect on the duration curves, but it gives in total lower losses. The result is in total more electricity available to cover consumption, which gives lower electricity prices.

The problem was in this report solved by multiplying all loss coefficients in MASKENETT.DATA by a factor of 5, as this resulted in in total about the same amount of losses as when using linear losses.