TR A6339

The Value of Load Shifting. An Estimate for Norway using the EMPS model

Gerhard Doorman
Ove Wolfgang

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May 2006

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TECHNICAL REPORT

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SINTEF Energy Research

Address: NO-7465 Trondheim, NORWAY
Reception: Sem Sælands vei 11
Telephone: +47 73 59 72 00
Telefax: +47 73 59 72 50

www.energy.sintef.no

Enterprise No.:
NO 939 350 675 MVA

SUBJECT/TASK (title)

The value of Load Shifting
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CONTRIBUTOR(S)
Gerard Doorman, Ove Wolfgang

CLIENTS(S)
Statnett SF

TR NO.	DATE	CLIENT'S REF.	PROJECT NO.
TR A6339	2006-05-19	Torkel Bugten, Inge Vognild	12X345.04
ELECTRONIC FILE CODE		RESPONSIBLE (NAME, SIGN.)	CLASSIFICATION
060214gd132537		Ivar Wangensteen	Unrestricted
ISBN NO.	REPORT TYPE	RESEARCH DIRECTOR (NAME, SIGN)	COPIES / PAGES
82-594-3047-9		for Petter Støa	15 / 51
DIVISION		LOCATION	LOCAL FAX
Energy Systems		Sem Sælands vei 11	73 59 72 50

RESULT (summary)

An attempt is made to estimate the value of Load Shifting (LS) in the Norwegian system, using the EMPS model. A thorough update of the demand side model and cost estimates used in the model was done as a preparation for the project, and the report gives a comprehensive description of the demand models used.
The LS measure that is analyzed is moving 600 MW demand in Norway from peak to lower demand hours during the day. The value of this was estimated both in a simplified manner (based on simulated price differences between these periods), and by simulations with the EMPS model and a subsequent calculation of the socio-economic surplus. Neither approaches showed any significant value.

The results do not necessarily mean that the value in reality is zero – there are a number of limitations in the model which make it difficult to estimate the real value, like the representation of wind generation, demand variability, outages, exchange prices with continental Europe, flexibility of hydro and thermal generation, reserves and elasticity of demand in the short run. It was verified through sensitivity calculations that especially increasing reserve requirements and increasing the variability of wind generation increased price differences and therefore the value of LS.

A number of improvements in the EMPS model and data are proposed to obtain a more suitable simulation model for this kind of analyses: 1) modelling of reserves, 2) representation of wind variability, 3) thermal generation models, 4) differentiation between long and short term price elasticity, 5) review of interconnection capacities, 6) use of quadratic losses and the 7) representation of more stochastic factors like e.g. outages in the simulations.

Although the model at present clearly has its limitations with respect to estimating the value of LS, it appears that price differences between spot prices in the actual hours in reality are small. Comparison with Nord Pool spot prices for the years 2003-2005 showed similar price differences between periods as simulated in the model.
The simulations indicate that when load is moved away from peak hours, it should be moved to the low load night period. Moving load within the day may have limited value.

KEYWORDS

SELECTED BY AUTHOR(S)		
	Demand Response	Load Shifting
	Socio-economic value	Simulation

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1 INTRODUCTION

In the context of the IEA Demand Respond Resource task, this report presents an attempt to estimate the value of Load Shifting (LS) in Norway, using the EMPS model. EFI's Multi-area Power market Simulator is used extensively in the Nordic power market for price forecasting, hydro scheduling and general market analysis[1]. The major focus of the model has been on energy balance analysis in the context of the variability of hydro inflows, and the model's features are well-suited for use in general hydro-thermal power systems. As the Nordic market moves in the direction of relatively more thermal and renewable generation, gradually more emphasis is put on EMPS' ability to correctly model short term variations in demand, generation and prices.

A description of the method used in the present analysis is given in the next Chapter. Before running the simulations, a thorough evaluation and upgrade of the existing data description was done, with emphasis on the modelling of the demand side. This is described in Chapter 3. The results for the reference case are presented in Chapter 4, while the case with load shifting is presented in Chapter 5. Some sensitivities are described in Chapter 6, while the report is finished with a discussion in Chapter 7 and a conclusion in Chapter 8.

2 METHOD

The objective of the analysis is to estimate the value of load shifting in Norway, using the EMPS model. Two important questions to be answered when doing this kind of analysis are:

- What *is* the value of load shifting or demand response in general and how should it be calculated?
- How should the stochasticity of the problem be handled?

The value of demand response in general has many well-known aspects, e.g. increased system security, reduced costs for running expensive generation, reduced investment costs and reduced peak prices. However, many of these aspects are difficult to value. In the present analysis the approach has been to calculate the difference in social surplus with and without demand response with a simulation with the EMPS model. Although we have limited ourselves to the case of (price-independent) load shifting, *in general* the effect of demand response on the social surplus can shortly be explained as follows:

> Because of demand response, the demand curve changes. Generally, it will change in the direction of more elastic behaviour – which in a way is the essence of demand response. If nothing else changes, the demand will be reduced in peak load periods and this gives an apparent reduction in consumer benefit. The reason is that consumer benefit is defined as the area below the demand curve. If the demand curve becomes more elastic, this area is reduced. The concept is illustrated in Figure 2-1.

[1] A short description of the EMPS model is given in Appendix I.

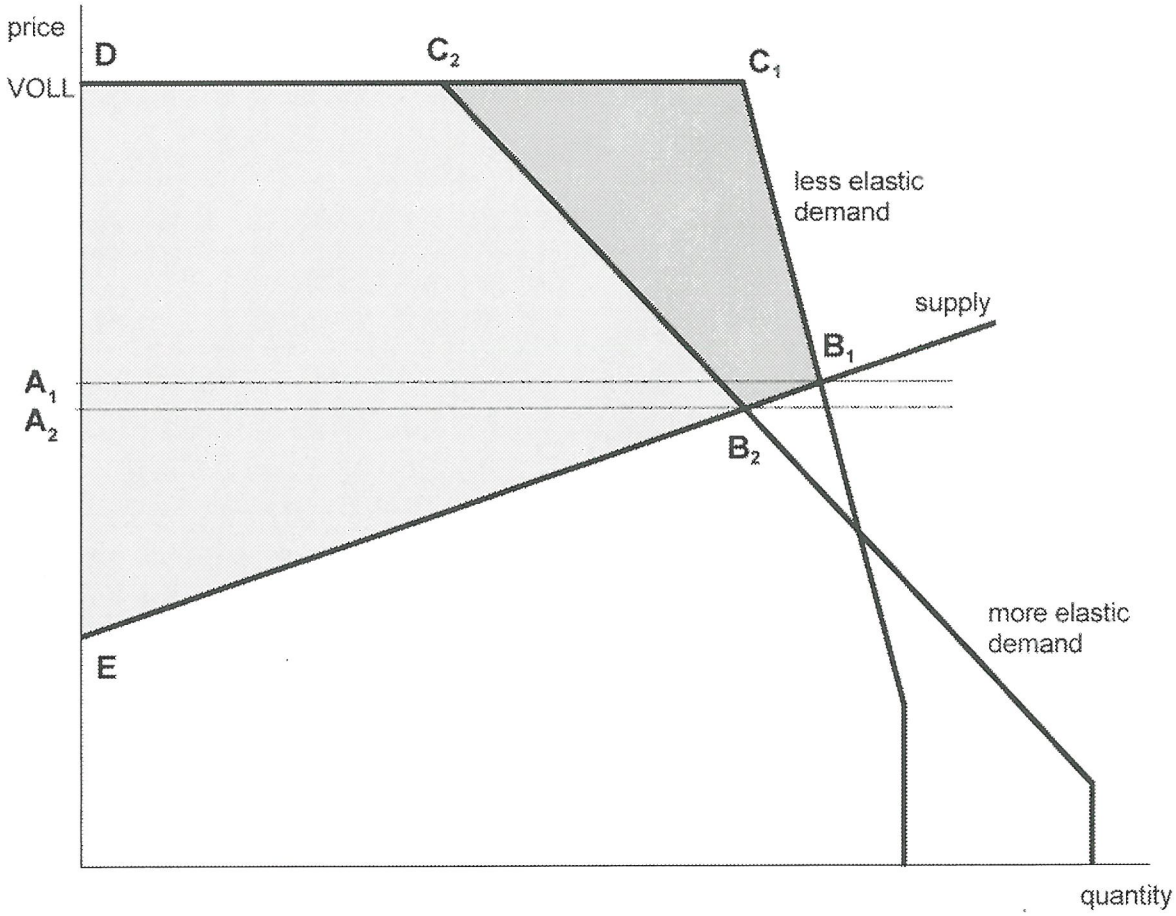

Figure 2-1: Consumer benefit in the case of changes in the demand curve.

The original demand curve is marked "less elastic demand". The demand curve is totally elastic at a very high level, given by the Value of Lost Load, VOLL[2]. Above a certain demand level, there is some elasticity down to a price where demand will not increase even if the price becomes zero. In this case the price is given by the intersection of the supply and demand curves in point B_1. Social surplus is given by the total grey area B_1C_1DE. A shifted demand curve is marked "more elastic demand" in the figure. With this demand curve, and assumed that supply is unchanged, the new equilibrium price is given by the intersection point B_2. Now social surplus is given by the area B_2C_2DE, which is less than the original area. The figure clearly shows that the reduction in social surplus mainly is caused by the apparent reduction in consumer surplus from $A_1B_1C_1D$ to $A_2B_2C_2D$.

However, this apparent reduction in consumer surplus may not be real. Firstly, if the reason for the shift in the demand curve is that consumers have been *exposed* to spot or real time prices there are no changes in consumers' preferences, but an elasticity that in fact already was there has been revealed. We have to compensate for this in the calculation of social surplus.

[2] For readability of the figure, VOLL is drawn at a relatively low value. In reality, VOLL would typically at least 10 times a normal price level.

Secondly, the shift in the demand curve gives reduced prices, and this increases the consumer surplus. In the case of very inelastic supply this effect will be larger than the apparent reduction in consumer benefit because of the shift in the demand curve. Finally, in the specific case of load shifting, there may be an actual reduction in consumer surplus in *one* period, but that this may be more than compensated by an increase in consumer surplus in *other* periods, e.g. when demand is shifted from one period to another. More discussion on this issue with direct reference to load shifting is given in Chapter in 3.

In the initial equilibrium, given by B_1, the true marginal utility of electricity consumption (given by the new demand curve at this quantity), is below the marginal production costs (given by the supply curve). The social surplus is therefore increased when the demand is reduced from B_1 to B_2, and the increase is given by the area demarked by B_1, B_2 and the intersection point between the supply curve and the new demand curve.

We focus on the short term effect of load shifting, which means that the effect on investments is not included in the analysis. The main effect of LS then comes from reduction of the alternative costs, i.e. expensive generation, imports and ultimately involuntary load shedding. An important property of load shifting is that the consumer does not experience any reduction in comfort (apart from possibly a feeling of "being controlled" for some persons). In other words, consumer utility is the same with and without LS. A limitation with load LS as implemented in the analysis (and in the real case we simulate as well) is that it is indifferent with respect to prices. This must be noted in relation to the explanation to Figure 2-1, which is more general and assumes that demand is price elastic. The main purpose of that explanation is to clarify the use of social surplus as a criterion for the valuation of demand response in general.

When social surplus is used as a criterion, the fact that prices may decrease as a result of LS is not explicitly defined as an advantage. Indirectly lower prices may often coincide with an increase in social surplus, but this is not necessarily the case, and the relation is not linear. But lower prices during peaks do not necessarily increase social surplus. The point is that to make the market more efficient, enough consumers should be *exposed* to prices and be able to react on them. If that leads to reduced demand and lower prices the problem is solved. If it does *not* lead to lower prices, there will be an incentive to build new generation capacity, provided it happens sufficiently often. But even though we do not use prices as an explicit criterion, we will still report simulated prices for the respective cases.

A major challenge with valuing LS is that its value may be extremely high, but that this value occurs very infrequently. This is especially the case in the Nordic system, where peak demand is strongly correlated with ambient temperatures in the area, and where extreme temperatures occur only seldom. This is illustrated by the fact that the record peak demand in Norway was 23054 MW in 2001, and has not been exceeded since. The previous record was from 1996. In addition, extreme demand may occur in a situation where generation capacity is reduced because of unfavourable hydro conditions. Analytically this creates three problems: i) how to make sure that the extreme cases are represented in the simulations without being overrepresented, ii) how to

estimate prices during such situations and iii) even when the value is high during special situations, will there still be a value on average?

In the EMPS model there are two sets of stochastic variables:

- Inflow to the hydro system
- Demand, influenced by temperature

Thus the simulations represent the variability in hydro generation and demand, as influenced by temperature, for the historical period that is simulated – in our case 1931-2000. This means that the results reflect the variability of these factors as observed for 70 historical years, applied on the present power system.

Additional uncertainty may be modelled:

- Outage probability of thermal plants with the IEC (Incremental Expected Cost) method
- Stochasticity of wind generation

These features were not used in the reference simulations.

We use the following approach: A data model of the present Nordic power system is established. Here a short outline of the data representation is given, while more detail on some features is given in the next Chapter. Power plants are represented at the plant level. Costs are estimated and updated to the 2005 level. Thermal plants are represented with capacity and marginal cost. CHP plants are modelled with a heat-dependent and a marginal power part, using different prices. Wind is represented on an average level. Exchange prices with Germany and Poland are estimated based on data for 2005. Hydro plants are represented at the plant level for Norway and Sweden, using hydrological data to represent the simulation period from 1931-2000. For Finland hydro power is represented at the country level, using estimated historical variations in hydro generation. Demand has an annual and weekly profile, and depends on observed temperatures – more detail is given in the next Chapter.

A base case is defined, where the modelled load shifting is approximately equal to the estimated existing level. This means that some heavy industry and boilers will react on relatively high prices. Subsequently a LS case is defined, and a new simulation performed. The value of LS is calculated as the difference in calculated social surplus for these two cases.

In the present model there are no major transmission constraints that result in large price differences between areas in Norway. In the base case calculation, LS is spread over the whole country, and if some areas have special problems resulting in higher price variations within the day, the increased value of LS for those areas would show in the results[3]. However, because there are no major transmission limitations in the model, given the distribution of the load between areas in 2005, this situation does not occur in the simulations. In the sensitivity calculations

[3] We specifically think of the situation in Central Norway which is much discussed presently.

reported in Chapter 6, we only look at the prices in Eastern Norway. It is evident that the value of LS would increase significantly in certain areas in the case of local or regional shortages.

3 DATA DESCRIPTION

In this Chapter we focus on the part of the data input to the simulations that has specific impact on the value of load shifting, and that was given special attention in the present project.

3.1 CURRENCY

The currency used in the simulations is Euro. We use both Euro/MWh and cent/kWh.

3.2 DEMAND

3.2.1 Total demand

In the EMPS model, demand is divided in "fixed demand" and "flexible demand". Fixed demand is given by three sets of parameters:

- Annual demand
- Annual profile, defined by 52 relative weekly values
- Weekly profile, described as a duration curve of up to 12 levels

The weekly profile is given as a set of relative values. In the simulations for this project, the weekly profile exists of 8 levels, called respectively:

Period Number	Period Name	Hours
1	Nordic high	9, workdays
2	Norwegian high	10, workdays
3	Swedish high	18, workdays except Friday
4	High day	11, 12, 17, 19, workdays + hour 18 on Friday
5	Low day	8, 13, 14, 15, 16, 20, 21, 22, workdays
6	Night	remaining hours workdays
7	Week-end day	
8	Week-end night	

Period 1 has the highest total Nordic demand, period 2 the highest Norwegian demand and period 3 the highest Swedish demand, as neither of these necessarily coincide. More details are given in APPENDIX II.

Flexible demand is in principle given by the same parameters, but in addition a disconnection price is defined. This means that the actual demand segment is disconnected if the simulated spot price exceeds this level.

The major part of demand in all countries in the Nord Pool area is modelled as fixed. This means that demand will continue independent of the simulated spot price. In the case that there are

insufficient generation and import resources, and all flexible demand is reduced to zero, the only way to obtain balance between demand and supply is to ration demand. In our case, this is done at a price of 37.5 cent/kWh.

Flexible demand in Norway is made up of power intensive industry as well as dual fuel boilers, estimated at a potential demand of 10 and 8 TWh respectively. This means that if prices are extremely low, total demand from these segments is approximately 18 TWh. In the simulations, average annual demand will be around 12 TWh.

Also for Sweden and Finland a minor volume of flexible boiler demand is modelled, but at a much lower level. For Denmark no flexible demand is modelled.

3.2.2 Demand profiles

More details about the calculation of demand profiles are given in APPENDIX II.

3.3 EXCHANGE PRICES

Costs of thermal generation, flexible demand and exchange with countries outside the Nord Pool area have been estimated on the basis of current oil and coal prices and prices on the German power exchange in 2004 and 2005. It is evident that such estimates are uncertain. The following figures show APX and Phelix exchange prices for 2004 and 2005:

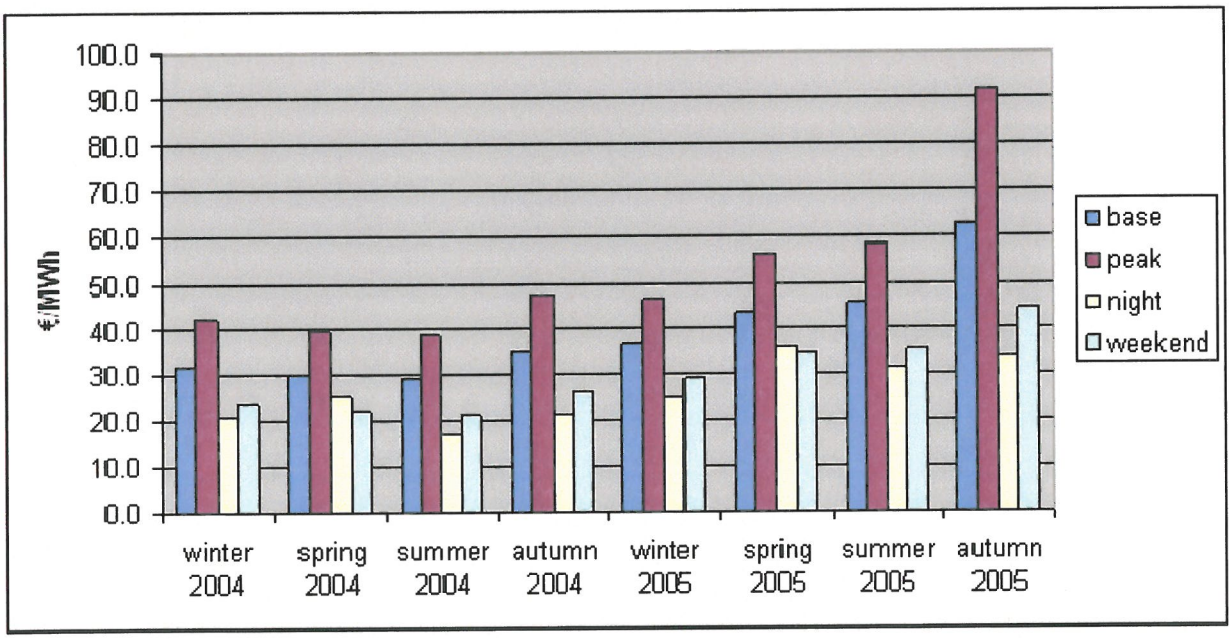

Figure 3-1: Prices APX (Montel base/peak and own calculations).

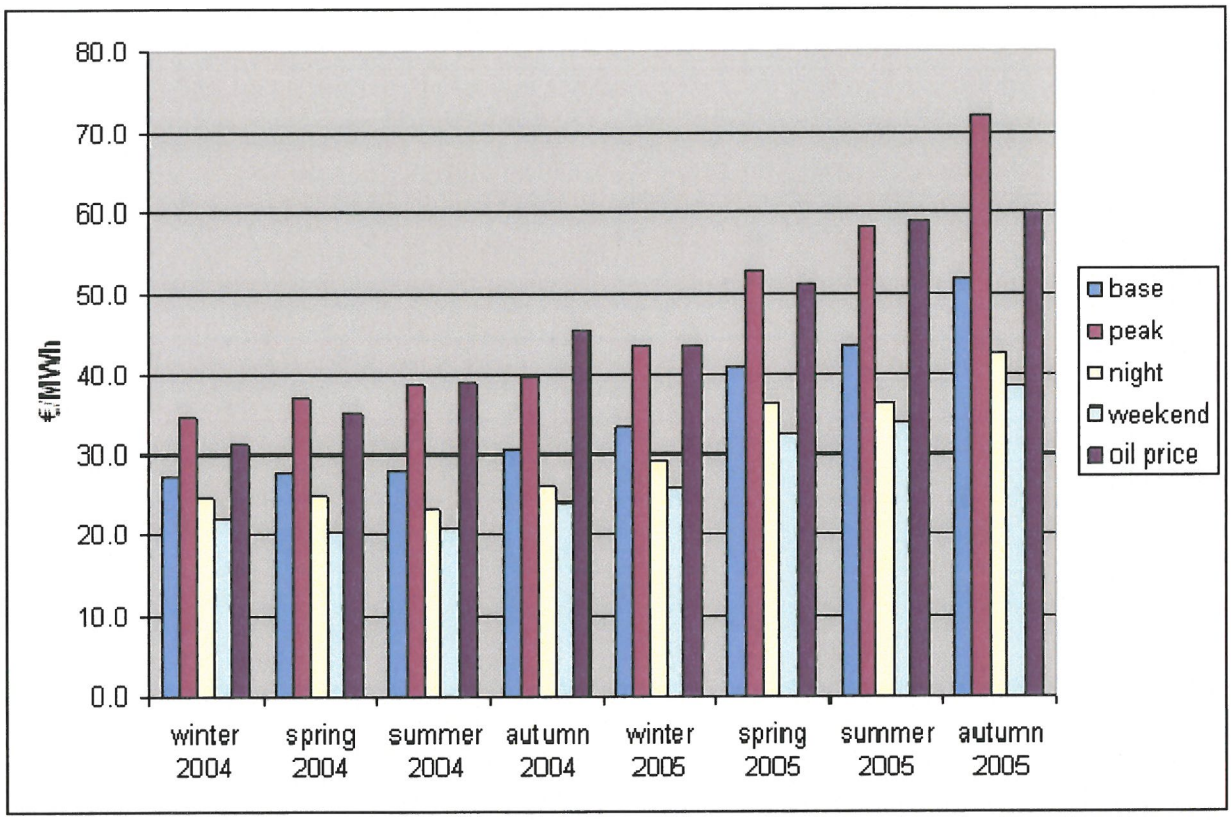

Figure 3-2: Prices Phelix (Montel base/peak and own calculations).

Prices in 2005 are significantly higher than in 2004. This partly due to increased fuel prices, partly due to the impact of CO_2 quota prices. We tried to distinguish between these effects by modifying the 2004 prices with the average crude oil price for each quarter, and assume that the remainder was the CO_2 effect. The results are shown in the next two tables:

Table 3-1: Estimated CO2 quota effect APX (€/MWh).

	Base	Peak	Night	Weekend
Winter 2005	-7.7	-12.4	-4.4	-4.1
Spring 2005	-0.1	-1.7	-1.3	2.5
Summer 2005	1.5	-0.4	5.5	3.3
Autumn 2005	16.1	29.2	5.5	9.3

Table 3-2: Estimated CO2 quota effect Phelix (€/MWh).

	Base	Peak	Night	Weekend	Night/wkd
Winter 2005	-4.8	-5.1	-4.9	-4.9	-2.1
Spring 2005	0.5	-1.0	0.0	2.9	4.0
Summer 2005	0.9	-0.1	0.8	2.2	3.0
Autumn 2005	11.8	19.4	8.1	6.8	5.1

The resulting effects are surprisingly equal, but they are not easy to use. There is no effect in the winter of 2005, which is not surprising because trading of quotas started on 1 April. The assumed effect is negative, indicating that a raw oil price correction is too strong. During the spring and

summer the effects are small, with the exception of the weekends. The reason may be that it is primarily coal plants that are affected, and that these are the marginal plants in the weekends. In the autumn there is a significant effect, especially during peak load. This is difficult to explain, market power may be part of an explanation.

An alternative approach is to use emission rates and an average quota price of 20 €/MWh. This gives the following costs:

coal:	0.8 tonn CO_2/MWh	→16 €/MWh
oil:	0.6 tonn CO_2/MWh	→12 €/MWh
gas:	0.4 tonn CO_2/MWh	→ 8 €/MWh
new gas plants:	0.3 tonn CO_2/MWh	→ 6 €/MWh

If we assumed that coal is mainly base load at gas is used during peak, this would imply that price differences between base and peak periods are reduced, but this is the opposite of what happens during the fourth quarter. Consequently, it is difficult to reach a conclusion, and we assume that the CO_2 effect on exchange prices is 10 €/MWh for all periods, which is added to the 2004 level.

For exchange within the EU, a general charge of 2€/MWh is applied. Moreover, we assume 3 % losses on the interconnections, which implies an increase respectively decrease of 0.9 €/MWh on import and export prices with an average price of 30 €/MWh. The resulting exchange prices with Germany and Poland are given in the following table

Table 3-3: Assumed exchange prices (cent/kWh).

Period	Import	Export
Day	5.03	4.45
Night	3.74	3.16
Weekend	3.46	2.88

3.4 RESERVES

The need for (primary and secondary) reserves is one of the factors that limits the availability of the generation system. The following table shows the Nordel reserve requirements/ recommendations for each of countries in the Nord Pool area:

Table 3-4: Summary of current active reserve requirements in Nordel.

	Consumption 2003 (TWh)	FAOR[1] (MW)	FACR[2] (MW)	FCR[3] (approx.) (MW)	FAOR + FACR + FCR
East Denmark	14	24	90	600	714
West Denmark	-	-	75	620	695
Finland	85	141	205	1 000	1346
Norway	115	192	313	1 600	2105
Sweden	145	243	303	1 200	1746
TOTAL	**358**	**600**	**1 000**	**5 020**	**6620**

[1]: Frequency Activated Operating Reserves
[2]: Frequency Activated Contingency Reserves
[3]: Fast Contingency Reserves

In simulations with the EMPS model, it is not straightforward how these reserves should be modeled. The objective of the analysis is to find the value of load shifting. If we assume that none of the reserves is ever available to serve demand, we may be too pessimistic, because (unexpected) extreme demand is one of the cases where reserves actually are activated to maintain the balance between demand and supply. As a compromise, we have kept aside the following generation resources for reserve purposes:

East Denmark: 415 MW of thermal capacity
West Denmark: 310 MW of thermal capacity
Finland: 840 MW of thermal capacity
Norway: 4 % of installed hydro capacity, approximately 1100 MW
Sweden: 1200 MW of gas turbine capacity in North, Mid and South Sweden

This amounts to approximately 4000 MW of generation capacity within the area that is not available to serve demand.

3.5 LOAD SHIFTING: REDUCED DEMAND FOR WATER HEATING DURING PEAK HOURS

In this project we study the effect of switching off 600 MW of electric water heaters in Norwegian households during peak hours, and reallocate this demand to the "Low day" period. In terms of the data description in the EMPS model as given in Section 3.2.2, this implies that 6 GWh (600 MW during 5x2 hours) is moved from the Norwegian and Nordic peak periods to the Low day

period. The 6 GWh per week is divided between the Norwegian areas according to relative annual general demand. It is possible to implement this change in the EMPS model in two different ways:

- Altered within–week profile
- Altered within-week market description

The within-week profile allocates the weekly demand to different periods within the week. Usually this profile is the same for all weeks in a year for general demand. If we adjust the within week profile so that 6 GWh is relocated within a particular week, then more than 6 GWh would be relocated in weeks with larger weekly demand and less than 6 GWh would be relocated in weeks with less weekly demand.

The alternative approach is to adjust the within-week market description. Ideally we want to shift the demand function in the peak load periods to the left (less demand for a given price) and at the same time we want to shift the demand function in the low load period to the right (increased demand for a given price). The demand in different areas in the EMPS model is however not given as explicit functions. For each unit in the dataset a quantity and a price is assigned. The assigned quantity is consumed by the unit only if the market price is less than the assigned price. A "demand function" can therefore be constructed as a step-wise function where the rationing cost is an upper cut-off price.

In the low load period we want to increase the demand for a given price, and we do this by defining a new unit that consumes the reallocated amount no matter how high the price is. The effect of this change is that the demand function shifts to the right and the consumed amount in that period increases with the reallocated amount if prices are constant.

In the peak load periods we want to decrease the demand with 600 MW. We cannot modify the relative profiles described in APPENDIX II, because this would result in a *relative* reduction of demand and not an *absolute* reduction. Neither can we define negative demand directly, but we can do so by defining corresponding generation. We therefore implemented reduced demand in the peak load periods in the model by including a new generation unit that offers the reallocated amount no matter how low the price is. This has the same effect as decreasing demand, but the calculated socio-economic surplus must be corrected correspondingly. How this is done is described in some detail in APPENDIX III.

4 REFERENCE CASE

4.1 ANNUAL BALANCE

Table 4-1 shows the annual balance for all four countries in the Nord Pool area. It must be pointed out that the simulation period is from 1931-2000, which results in significantly lower hydro generation than the period 1971-2000, which is normally used by NVE. For Norway the difference is approximately 6 TWh.

Table 4-1: Average annual balances.

	Hydro	Thermal	Wind	Net Import	Demand	Rationing
Norway	113.0	1.5	0.0	10.3	124.8	0.3
Sweden	62.8	73.1	0.0	12.6	148.6	0.1
Denmark	0.0	39.7	6.0	-9.4	36.3	0.0
Finland	12.3	63.2	0.0	11.7	87.2	0.0
Nord Pool area	188.2	177.5	6.0	25.2	394.5	0.3

Although both Norway, Sweden and Finland have some wind power, this has not been included in the model. Import to Finland is mainly from Russia (10.5 TWh). Both Norway and Sweden have significant imports. Although Denmark exports more than 9 TWh, net import to the Nord Pool area is 25 TWh, of which approximately 15 TWh comes from Germany and Poland.

Figure 4-1 shows percentiles of simulated Norwegian peak demand. The maximum is approximately 22500 MW. Arguably, this is somewhat low, given the fact that demand was in excess of 23000 MW in 2001.

Figure 4-1: Percentiles (0, 25, 50, 75, 100) of Norwegian maximum demand (MW).

Figure 4-2 shows corresponding percentiles of Norwegian generation during peak.

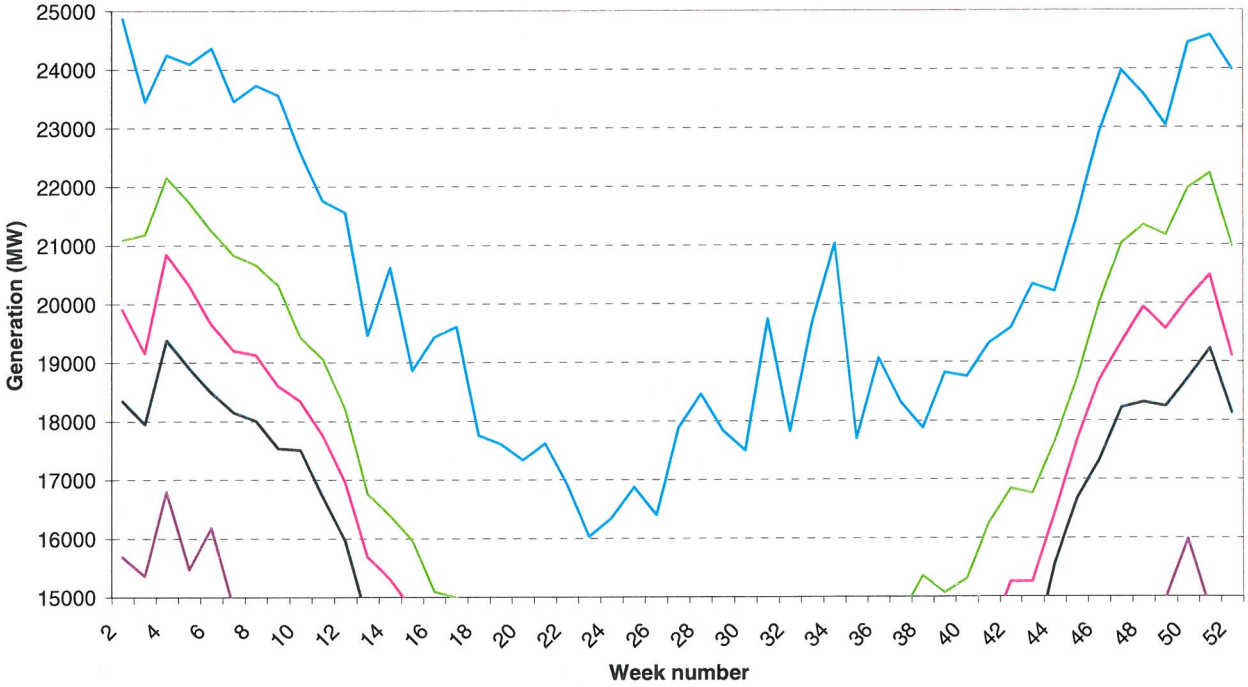

Figure 4-2: Percentiles (0, 25, 50, 75, 100) of Norwegian generation during peak (MW).

Simulated generation looks reasonable, given the fact that generation was in excess of 24000 MW some hours in 2006.

We have looked closer at the reasons why demand is not higher than 22500 MW. Disconnection prices for price elastic industrial demand and boilers are based on assumptions of long term elasticity. However, in the model it is presently not possible to distinguish between long and short term elasticity. As a result, (part of) these segments will be disconnected immediately when prices exceed 3-5 cent/kWh. This gives a reasonable annual demand, but the effect is disconnection during all hours when general demand is very high, resulting in moderate total demand. We have done a test where the disconnection price of industry and boiler demand was tentatively increased with 10 cent/kWh, making this demand virtually inelastic with normal price levels. This resulted in a peak demand around 24000 MW in Norway, but an annual demand of 130 TWh. Work is presently going on to improve the model in this respect.

4.2 ELECTRICITY PRICES

Average prices for the region Østland is illustrated in Figure 4-3.

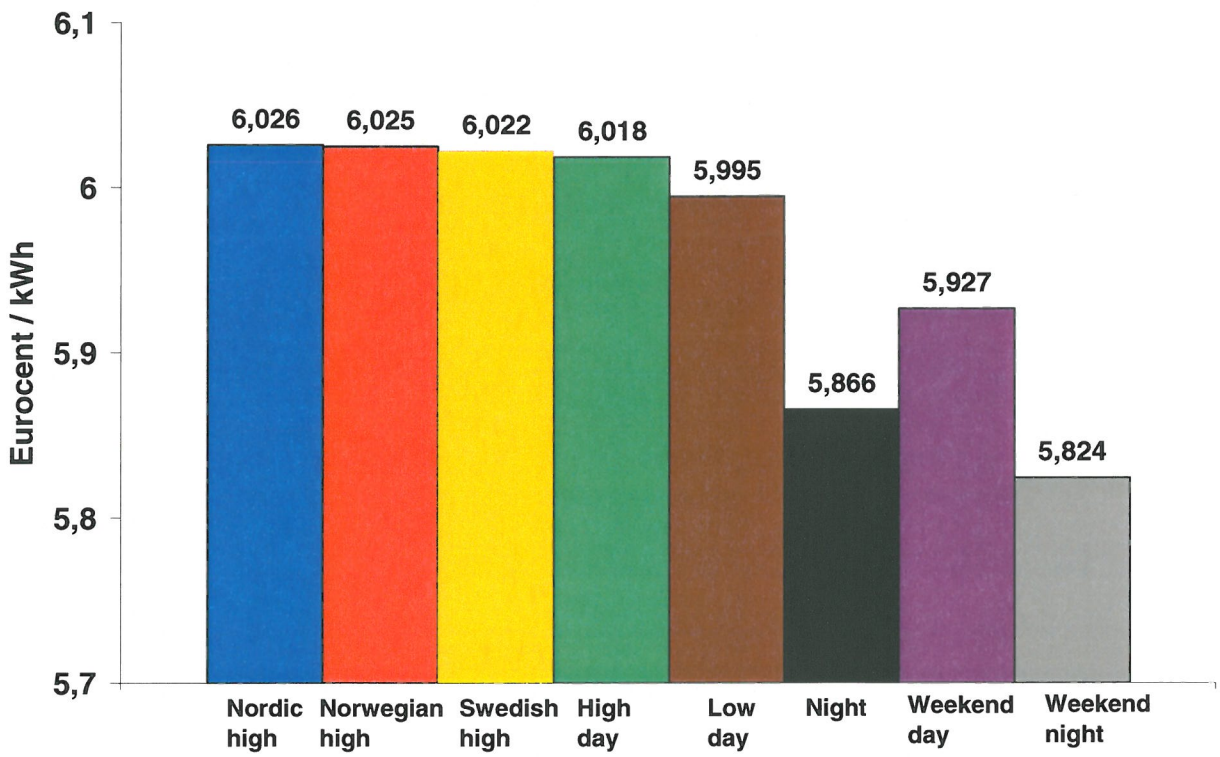

Figure 4-3: Average within-week prices per kWh for area Østland in reference case.

Average prices are largest in the period "Nordic high" followed by "Norwegian high", "Swedish high" and "High day". The differences are however very small between the day periods for ordinary working days.

Generally, prices appear to be somewhat higher than is observed in the present system. We have done no further attempts to reduced thermal costs and/or increase demand elasticity, as this is not essential for the present analysis. However, the most interesting factor in our context is the price *difference* between the Nordic and Norwegian high and Low day segments. A price difference of 0.031 cent/kWh is observed (appr. 0.2 øre/kWh) in the simulations. To verify this against reality, we calculated average prices in hours 9-10 (Nordic and Norwegian high) and 14-15 (low day) respectively for the years 2003-2005, based on Nord Pool data.

Table 4-2: Observed price differences between peak and low day, Oslo.

Year	Average annual price, øre/kwh		Price difference	
	Hour 9-10	Hour 14-15	Øre/kwh	Cent/kwh
2003	30.8	30.1	0.8	0.1
2004	25.5	25.1	0.4	0.05
2005	24.6	23.7	0.9	0.1

We also found that price differences between day and night for these years were approximated 0.2 cent/kWh. This clearly shows that real price differences normally *are* extremely small, although somewhat higher than in our simulations. Of course the value of LS does not appear on the average day, but lies in the avoidance of "disaster" on one or very few extreme days. On the other hand, the long run value *does* come from the average day – even though the average may consist of one thousand zeros and one extreme value.

4.3 BACK-OF-ENVELOPE-CALCULATION

Since we reallocate demand from the periods "Nordic high" and "Norwegian high" to "Low day" in all 70 stochastic scenarios we know a priori that the increase in socio-economic surplus per kWh is no higher than the initial average price differences per kWh between the peak load hours and "Low day" multiplied with 6 GWh.

The average difference between "Low day" and the peak load periods "Nordic high" and "Norwegian high" is approximately 0.031 cent per kWh, cf. Figure 4-3. If prices are similar in the other Norwegian regions the maximal gain of reallocating 6 GWh per hour from the peak load hours to "Low day" is approximately

$$6000 \text{ MWh} \cdot 52 \text{ weeks} \cdot 0.31 \text{ Euro/MWh} = 96720 \text{ Euro/year}$$

It is clear that average price differences between "Low day" and the peak load periods in our reference case are so small in these simulations that the socio-economic surplus will be almost unaffected by this reallocation of demand.

5 LOAD SHIFTING CASE

5.1 CASE DESCRIPTION

The LS case is identical to the reference case except that we have reallocated 6 GWh/week in Norway from the periods "Nordic high" and "Norwegian high", to the period "Low day". The number of hours for the periods "Nordic high" and "Norwegian high" is 10 per week, while there are 41 "Low day" hours per week. The effect per hour is therefore a 600 MW reduction for "Nordic high" and "Norwegian high" and a 146 MW increase for "Low day". The changed demand is distributed between Norwegian areas in proportion to the annual relative general demand in the input data. See section 3.5 for details about the implementation in the EMPS model.

5.2 ELECTRICITY PRICES

The average prices for Østland in reference case and LS case for different within-week segments is illustrated in Figure 5-1. Prices declines by 0.027 cent per kWh in the two periods where the demand is reduced, while prices are increased by 0.009 for the "Low day" period where demand has increased. The effect of this change is therefore very small on average prices. For the other periods there are only small changes in average prices.

Even though there are small differences in average prices, prices can change a lot in single days and periods, and for these hours there are potential gains of reallocating demand. Figure 5-2 shows how the maximum, minimum and average price changes for each week for period "Nordic high". There is a small decline in the average price for each week, but there are large variations between different stochastic scenarios. The largest price reduction is somewhat above 2.8 cent / kWh. For that particular day we study how prices are changed in all periods, cf. Figure 5-3. This is a day with inflow from 1942, and there is large probability for energy shortage in this scenario.

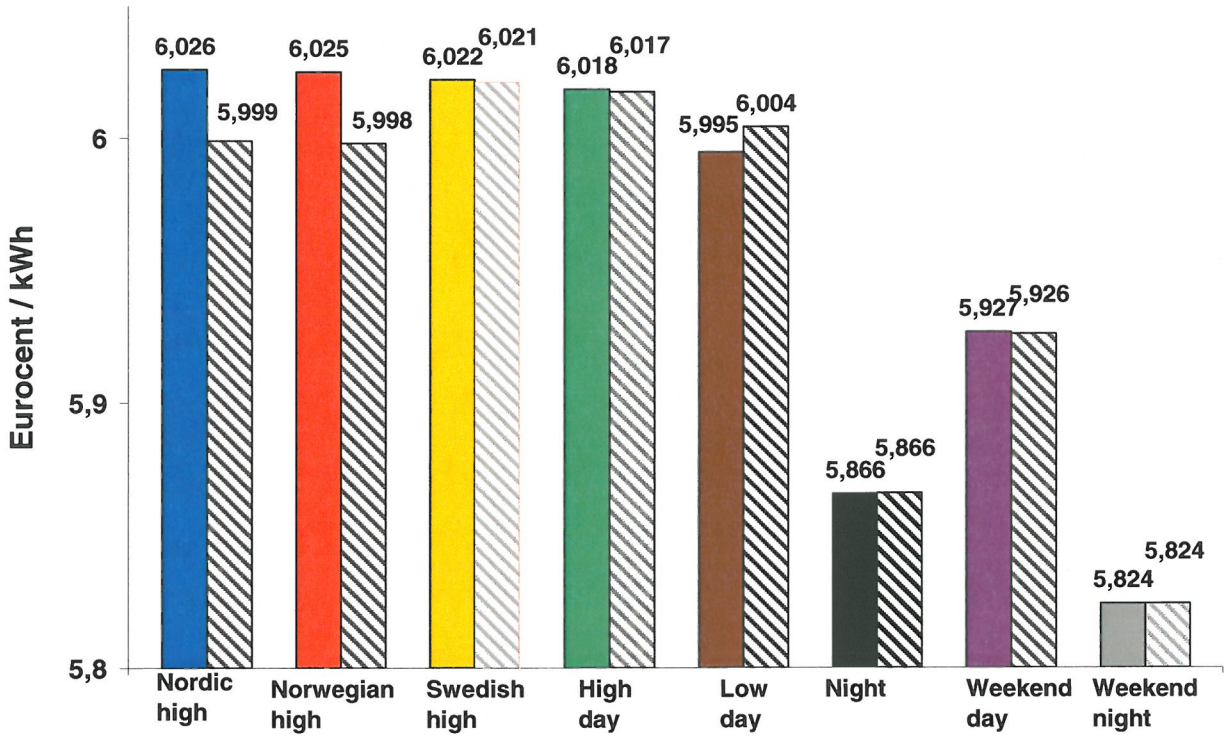

Figure 5-1: Changed average prices from reference case (solid) to LS case (stripes) for area Østland.

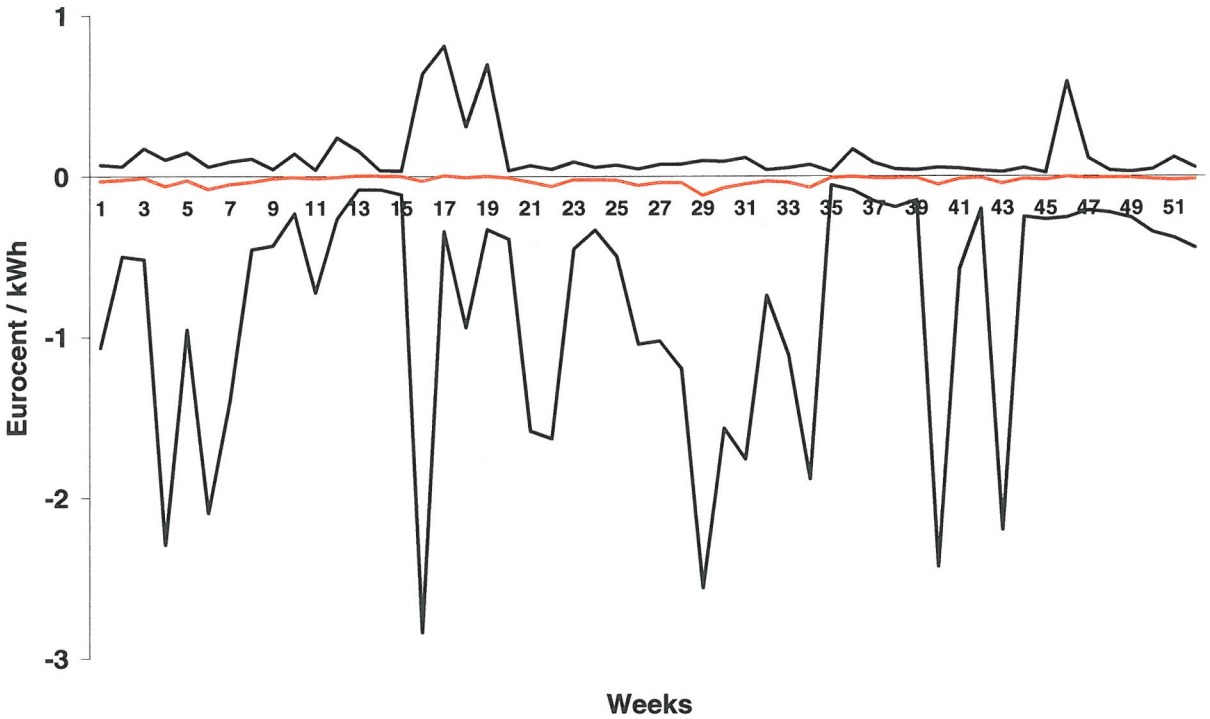

Figure 5-2: Changed prices in "Nordic high" from reference case to LS case for area Østland (maximum, minimum and average in 52 weeks)

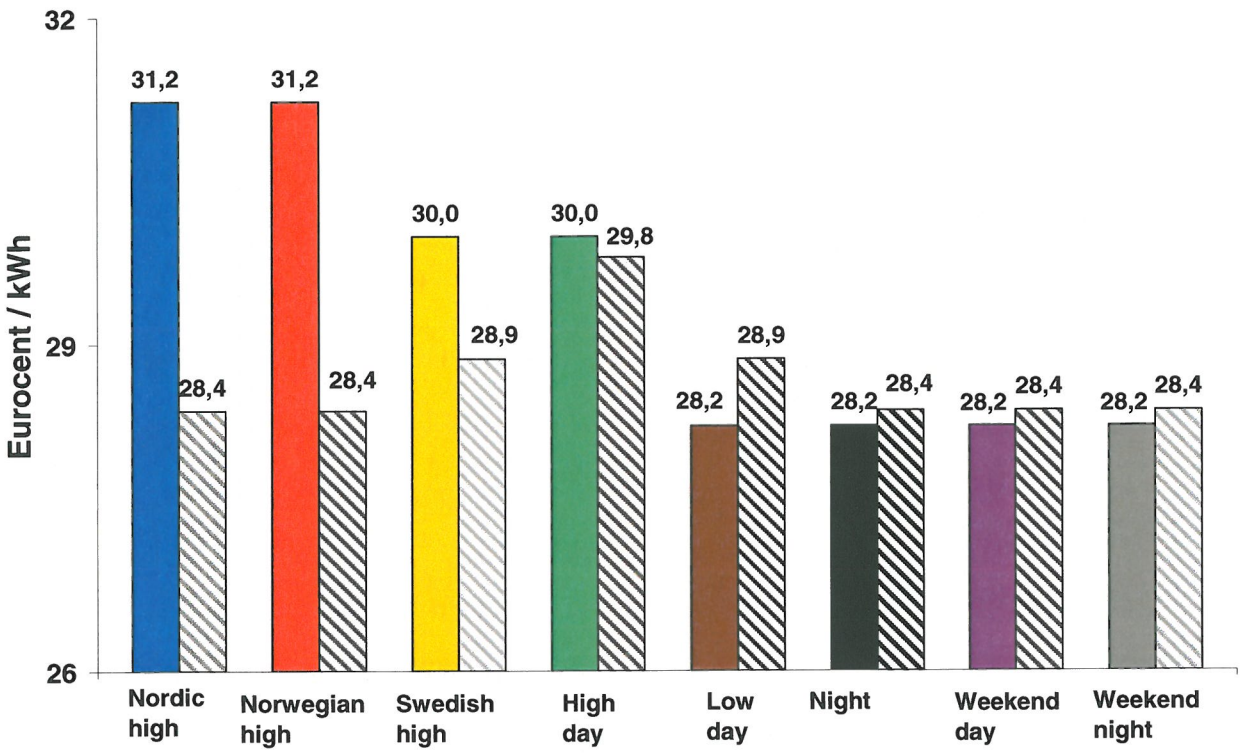

Figure 5-3: Changed prices from reference case (solid) to LS case (stripes) for area Østland in a selected day with inflow from 1942 (energy shortage).

Prices can be a lot larger than water values in the peak load periods in cases where the demand is close to the capacity limit of the power system even though there is ample supply of hydropower. In such cases the prices could be much larger in peak load hours than in normal working day hours. But in our simulations there were no occasions of capacity problems of the power system. If we had modified assumptions so that the power system had been more stressed during peak load periods it is likely that there would be larger differences between prices of different within-week periods. On the other hand it is likely that the system in most cases would be stressed in peak load and in the "Low day" period if we had provoked capacity problems.

5.3 SOCIO-ECONOMIC SURPLUS

The EMPS model calculates the socio-economic surplus (consumer surplus plus producer surplus) for each stochastic scenario. The surplus for Reference case and Case 1 in Table 5-1 is taken from EMPS output files. The adjustment of the surplus for Case 1 is calculated in APPENDIX III.

Table 5-1: Gain of reallocating demand (million Euro).

	Surplus Case 1	131306.72
-	Adjustment	117.31
=	Surplus Case 1 adjusted	131189.41
-	Surplus Reference case	131189.84
=	Gain of reallocating demand	- 0.43

The calculated change in the average socio-economic surplus because of reallocating 6 GWh/week from "Norwegian high" and "Nordic high" to "Low day" is - 0.43 million Euro per year. Theoretically, the difference should be zero or slightly positive, and the negative value must be the result of limited accuracy and coincidence (the value is only 0.0003 % of the total economic surplus).

6 SENSITIVITIES

A number of assumptions and simplifications were made in order to do the present analysis. In this Chapter we will look at some of those assumptions, and do some alternative calculations, in order to try to identify why the results show no value of LS and how they might be improved. In these analyses we do not run new simulations with LS, but look at intra-day price differences under varying assumptions, because these are the driving factor for the value of LS. This simplified approach normally overvalues LS, because price differences would be reduced with the introduction of LS. Still the approach gives an indication of the level of the value.

6.1 MOVE LOAD TO NIGHT

In the analysis so far we have moved 600 MW of load from peak hours to "Low day", assuming that load only can be delayed a few hours. This is based on the idea that this can be realized by using water heaters, using simple and cheap technology. The same technology could easily be used to delay reheating of water until night hours, but this might have a comfort impact. If we forget this problem, and assume that reheating could be delayed to night hours, the value of LS would increase, because night prices generally are lower.

To illustrate the problem with moving load between fixed hours, and especially within the day, Figure 6-1 shows the relative number of days each hour had the highest price in the years 2003-2005. E.g. the value 0.29 for hour number 9 means that this hour had the highest daily price in 29 % of the days in these years. Said in another way, moving load from this hour would miss the highest price in 70 % of the cases.

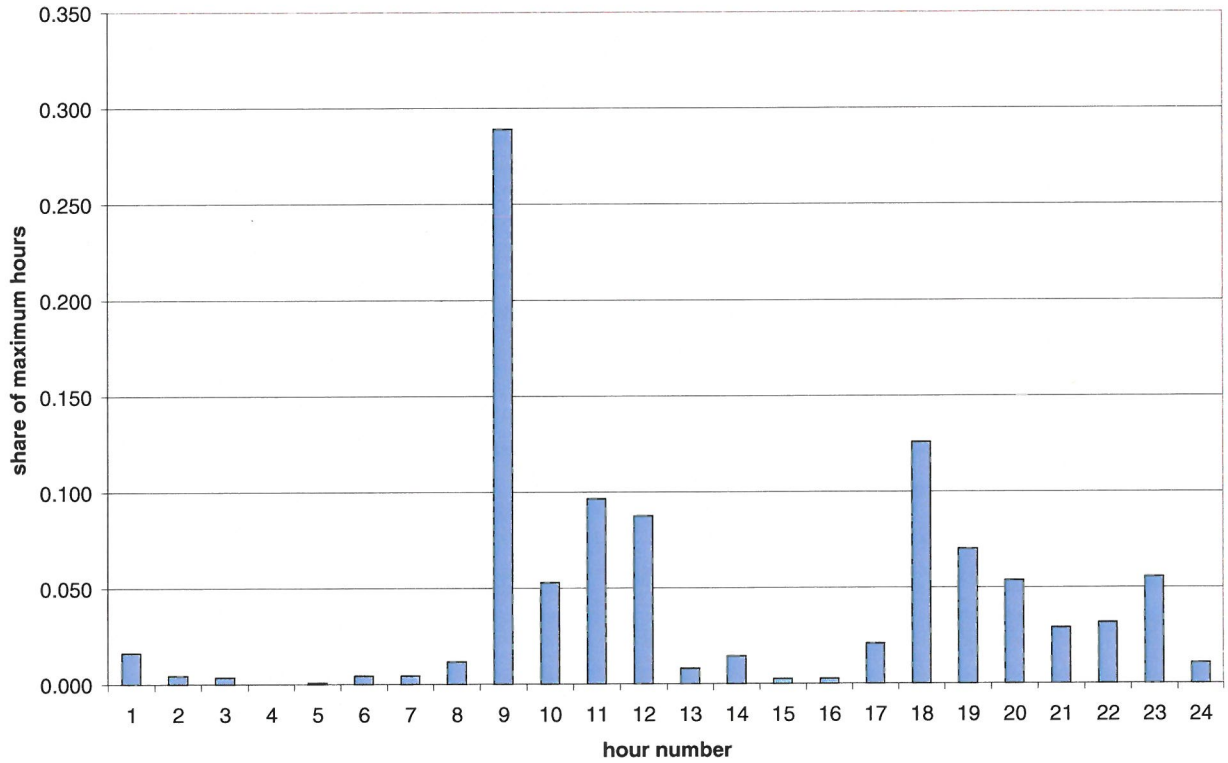

Figure 6-1: Share of maximum load hours.

While the average price difference between peak and low day was only 0.031 cent/kWh, it appears that the difference between peak and night is 0.161 cent/kWh for area Østland. With the same price differences for other areas in Norway, the resulting value of LS would increase to approximately 500.000 Euro/year if 600 MW of peak load could be moved to the night instead of low day. The highest value is 2.2 million Euro in one year. However, like before the highest values occur in dry years, when the general price level is high, and not necessarily during the years with highest demand. On the other hand, there may be some realism in this – in extremely dry years hydro generation will generally be somewhat lower.

Although the simulated value of LS increases when load is moved to night, it is still not impressive, even in extreme cases.

6.2 REDUCED ELASTICITY OF INDUSTRIAL AND BOILER DEMAND

As pointed out before, one of the problems with the model is that especially industrial and possibly also dual fuel boiler demand are modelled with a view to long term elasticity in the case of energy shortage. However, the same elasticity will occur in the short run, reducing demand unrealistically during extreme peak hours. To check the significance of this effect, we reduced the elasticity of these demand segments by increasing their disconnection price with 10 cent/kWh. This does not give realistic results in the long run, significantly overestimating demand especially in dry years, but it might give increased price differences on days with high demand.

It appears that in this case, average annual demand in Norway increases (unrealistically) to 132.5 TWh. Figure 6-2 shows the resulting percentiles of Norwegian peak demand.

Figure 6-2: Percentiles (0. 25. 50. 75, 100) of Norwegian peak demand, reduced price elasticity

The general price level increases significantly. However, it appears that price *differences* between peak and low day only increase slightly from 0.031 cent/kWh to 0.036 cent/kWh. The price difference between peak and night increases from 0.16 go 0.20 cent/kWh. Apparently, the intra-week flexibility in the model is sufficient to support even such a large increase in demand.

6.3 WIND MODELLING

Wind generation in Denmark is modelled with a fixed annual amount and a 52-week profile. This means that wind generation varies between weeks, but not between years. The reason is that there are no wind data available for the period from 1931-1960, and we presently do not have wind data for 1991-2000. To get an impression of the significance of this simplification we extended available wind data for the period 1961-1990 to the periods 1931-1960 and 1991-2000. This was done by using the data for 1961-1990 for the period 1931-1960, and data for 1961-1970 for the period 1991-2000. It is obvious that data for the extended period are wrong, but they introduce a variability that was not present in the original data set.

For this case, we have also looked at prices in Western Denmark. The results are summarized in the following table, which shows price differences between peak / low day as well as peak / night:

Table 6-1: Simulated price differences.

		Østland		West Denmark	
		Reference	Variable wind	Reference	Variable wind
Peak vs low day	Winter	0.042	0.056	0.113	0.296
	Summer	0.021	0.016	-0.200	-0.150
Peak vs night	Winter	0.089	0.168	1.326	1.038
	Summer	0.232	0.206	0.381	0.493

From the table we see that with variable wind, price differences increase during winter, but decrease during summer. Overall, there is an increase in price differences, most significantly between peak and night for area Østland in winter. The value of a shift of 600 MW from peak to low day is still insignificant, but a shift from peak to night would under these assumptions create an average annual value of almost 600.000 Euro per year. The highest simulated value is almost 6 million Euro for one year, and 10 % of the years exceed a value of 1 million Euro.

It is important to realize that the variability in wind introduced here is a variability *between years*, not within the week. Wind generation in the model is still constant within a week, but varies between weeks and years. The result is that there will be some situations where there will be little wind, increasing the price level during those weeks. This does not necessarily lead to higher price differences *within the day*, but it may in those circumstances where total generation capacity becomes a binding constraint.

6.4 INCREASED RESERVE REQUIREMENTS

Relatively limited reserve requirements were used in the simulations, as discussed in Section 3.4. To verify the impact of reserve requirements, we increased the reserve requirements in Norway to 20 % of installed hydro capacity, approximately 5600 MW. Hydro generation in Norway will then be restricted to approximately 22000 MW. Clearly, this is unrealistic. On the other hand, we may have used too limited reserve requirements in the other countries. Moreover, our initial modelling underestimates the effect of reserve requirements, because capacity that cannot be used due to hydraulic constraints is included as reserves.

This considerable limitation of hydro power generation does increase price differences between peak and low day somewhat, but still not significantly, to 0.070 cent/kWh, against 0.031 in the reference case. The estimated maximum value of LS increases to approximately 200.000 Euro in one year. Under these assumptions, the average value of moving 600 MW of peak demand to the *night* would be 700.000 Euro per year, with a maximum value of 3.5 million Euro for one year. 14 % (10 years) of the simulated years have a value of more than 1 million Euro

6.5 VARIABLE WIND AND INCREASE RESERVE REQUIREMENTS

We have finally looked at the combination of variable wind modelling as in Section 6.3 and increased reserve requirements as in Section 6.4. This results in an average *annual* price difference between peak and low day of 0.103 cent/kWh, 0.183 in winter and 0.023 in summer. In this case the average annual value of LS increases to 300.000 Euro. Moving 600 MW of peak demand to the night in this case would have a value of 1 million Euro per year, with a maximum 8.4 million in one year.

The following table sums up the major results from the sensitivity analyses in this Chapter:

Table 6-2: Overview sensitivity analyses.

Case	Average annual price (cent/kWh)	Average delta peak – low day (cent/kWh)	Average annual value LS peak → low day (mill. Euro)	Average delta peak – night (cent/kWh)	Average annual value LS peak → night (mill. Euro)	Max annual value peak → night (mill. Euro)
Reference	5.93	0.031	0.096	0.160	0.500	2.2
Red. elasticity	7.55	0.036	0.108	0.197	0.616	2.3
Var. wind	5.90	0.036	0.109	0.187	0.584	5.7
More reserves	5.94	0.070	0.211	0.229	0.714	3.6
Wind + reserves	5.89	0.103	0.309	0.315	0.982	8.5

None of the model changes that have been tested has any significant impact on the *average* annual price level, with the exception of the Reduced Elasticity case, which leads to a considerable increase in demand as discussed in Section 6.2. Moreover, the Reduced Elasticity and Variable

Wind cases in isolation do not lead to significant changes in the value of LS, neither for shifting from peak to low day nor for shifting from peak to night. Interestingly the maximum value more than doubles for the Variable Wind case. When this case is combined with the More Reserves case, the average price difference between peak and night roughly doubles, while the difference between peak and low day triples, with corresponding results for the value of LS. The maximum value quadruples compared with the Reference case.

These results indicate that if the stochastic behaviour of demand and supply can be modelled more realistically, and this is combined with a better description of the constraints in the system, the EMPS model may well be suited for this kind of analyses. In the next Chapter we describe a number of proposals to develop the model in this direction.

7 DISCUSSION

The simulations described in this report have not bee able to demonstrate a positive value for the type of demand side response that was analyzed: a form for peak-shaving, where 600 MW during peak in Norway was moved to off-peak during day time. With hindsight, the result is not surprising, given the small price differences between peak- and off-peak periods in the simulations. We have compared these price differences with actual differences in the years 2003-2005. Although observed price differences are slightly higher than the simulated differences, the real prices in these years would not have resulted in any significant value of LS either. This reflects the capacity balance in the present Nord Pool system, and to some extent this is the result of actions already taken by the TSOs. However, this may change in the future due to several trends: increased demand (especially in Norway) and more generation with lower peak contribution (nuclear, gas base load, wind).

It is evident that in special cases, the value of LS can be very high even in the present system. The intention of the project was to demonstrate this value, under the assumption that simulation of 70 years of historical observations of inflow and temperatures would include a number of instances with a high value of LS. We have, however, not been able to identify such events.

Although the value of this type of LS was insignificant in the simulations we performed, there are a number of model and data modifications that would make the model more realistic, and that might result in a higher simulated value of LS:

1. Modelling of reserves.
In the previous Chapter we discussed the handling of reserves, and conducted one experiment with increased reserve requirements in Norway. The need for reserves has a significant impact on the availability of generation resources during peak demand. There clearly is a need for better modelling of reserve requirements in both hydro and thermal plants. Some more consideration should also be given to the interaction between the spot and balancing markets. The total requirements for primary and secondary reserves, 6620 MW on a Nordic basis, should be kept unavailable, in excess of modelled generation that is unavailable for other reasons. The present modelling of reserves includes hydro resources that are unavailable for hydraulic reasons in the reserve pool, which is unrealistic. On the other hand, it can be questioned if it is realistic to assume that no reserves will be used to serve demand during extreme conditions, when load may be shed. A closer look should be given to these factors.

2. Wind variation within the day
The sensitivity analysis in the previous Chapter showed that increased variability of wind generation increased the value of LS in the simulations. Still, the variation that was imposed only addressed variation between historical years, not within the week. Variation *within* the week clearly would increase the probability of insufficient generation during peak. Exactly *how* this should be modelled is not clear, given that EMPS uses a weekly duration curve. But some method should be developed to map weekly variation in wind availability to the EMPS load model.

3. Thermal generation models

Thermal generation is modelled by a marginal cost and a capacity. Unit commitment is not taken into account. A simplified linearized model of unit commitment is presently under development at SINTEF. Inclusion of this model will lead to increased price differences between load segments.

4. Differentiation between short and long term price elasticity

It has been pointed out that the inability to differentiate between short and long term price elasticity results in unrealistic reduction of demand in Norway when prices are high during short periods. A comparison between Figure 4-1 and Figure 6-2 indicates a reduction of 1500 MW. During long periods of prices at a level of, say, 8-10 cent/kWh, it is reasonable to assume a significant demand reduction in the industrial sector. However, during short periods of a few hours, this demand will not or only to a very limited degree be reduced. Work is presently going on at SINTEF to differentiate between short and long term price elasticity. It is probable that also this model enhancement will increase price differences between load segments.

5. Interconnection capacities

The results indicate that the overall flexibility to serve load is too high in the model. There are a number of reasons for this, which is the subject of the present discussion. One additional reason may be that interconnection capacities are too optimistically modelled with respect to their availability during peak demand (and probably also with respect to long term energy transfers). A thorough revision of these capacities may result in a more realistic model.

6. Quadratic losses

Losses on interconnections between areas are calculated with a linear approximation. EMPS allows a quadratic (and much more realistic) calculation of interconnection losses, but these have not been implemented in the present model. A major reason for this is that we presently do not have appropriate data to estimate the loss factors.

7. Other stochastic factors

As discussed in Chapter 2 of this report, the major challenge is a realistic representation of the stochasticity of the problem. Even if all of the issues listed above have been taken appropriately into account, we still use an averaging of a number of factors. The result is that the extreme events are not represented. An alternative approach was chosen in [2], where a number of stochastic factors were identified and described by probability distributions. By drawing from these distributions, taking into account correlations between the factors, 100 system states were drawn for week 5, which was subsequently simulated using the Balmorel model.

In the EMPS model, hydro inflow and demand stochasticity are modelled by the use of historical inflow and temperatures, while other parameters are considered deterministic. Thermal generation availability is to some extent considered by the IEC method, but this only increases prices and does not lead to a physical availability reduction.

For a better representation, one could draw a number of parameters from probability distributions in a similar way as was done in the Danish project [2]. The most important factors are probably demand, plant availability and exchange prices. Another factor to be considered is interconnection availability. A possible approach could be to estimate the statistical properties of each of these parameters. For demand this means the variability after temperature dependency has been taken into account, i.e. the uncertainty in demand that is not explained by temperatures. For each week or possible load segment, the value of each parameter could then be drawn from their respective probability distributions, resulting in considerably more variation then is observed today. Probably more than 70 years should be simulated to obtain a good representation of the total variations. With respect to calculation times this is no problem, the calculations in this report typically take 10 minutes on a 1.9 GHz Pentium laptop computer, although calculation times will increase somewhat with the proposed model enhancements, specifically point 3 above. There are some challenges with respect to the storage and handling of results, which may become cumbersome when e.g. simulating 1000 years, but these can certainly be overcome.

8 CONCLUSION

The objective of the project described in this report was to demonstrate the value of load shifting in the Norwegian market. As a LS case, the moving of 600 MW of load from peak (hours 9-10) to low day (hours 14-15) was analyzed.

In the reference case, the simulated value of this appeared to be virtually zero. This does not mean that the value in reality *is* zero – there are a number of limitations in the model which make it difficult to estimate the real value. There are two groups of such limitations:

- Limited variability (wind representation, demand, outages, exchange prices with continental Europe)
- Too much flexibility (Hydro and thermal generation, reserves, elastic demand in the short run, exchange capacities)

In addition the use of linear losses also overestimates the flexibility of the interconnections. Together these factors have the effect of smoothing out price differences between load periods, which reduces the value of LS. It was verified that price differences and the value of LS increase when the model is changed in some of these respects. Specifically the use of more variable wind data and increased reserve requirements (which probably gives a more realistic total availability of the generation system) increase the value of LS, especially in extreme cases.

A number of improvements in the EMPS model and data are proposed to obtain a more suitable simulation model for this kind of analyses: modelling of reserves, representation of wind variability, thermal generation models, differentiation between long and short term price elasticity, review of interconnection capacities, use of quadratic losses and the representation of more stochastic factors like e.g. outages in the simulations. Some of these improvements are currently under development in other projects.

Although the model clearly has its limitations, it appears that price differences between spot prices in the actual hours in reality *are* small. Observed differences in the years 2003-2005 between hours 9-10 and 14-15 for Oslo were 0.05 – 0.1 cent/kWh, while the simulations showed an average value of 0.03 cent/kWh for the reference case and 0.1 cent/kWh for the case with variable wind and increased reserve requirements. Real price differences between day and night in these years were approximately 0.2 cent/kWh, which is not far from the simulated values. This shows that the model *on average* is not far from reality, but it probably does not represent the extremes realistically.

The simulations indicate that when load is moved away from peak hours, it should be moved to the night period. Moving load within the day may have limited value.

REFERENCES

[1] Doorman, G. and O. Wolfgang (2004), "Simulations of the Capacity Balance in Norway and Sweden", TR A5986, SINTEF Energy Research.

[2] Grenaa Jensen, S., T. Engberg Pedersen, Mikael Togeby (2006), "Valuation of demand response. A Monte Carlo analysis for the Nordic power system"

APPENDIX I THE EMPS MODEL

The EMPS model is a stochastic model for optimization and simulation of system operation in cases where hydropower plays an important role. The optimal scheduling of hydro-resources is sought in relation to uncertain future inflows and demand, thermal generation and options for doing transactions in domestic as well as international electrical spot markets. Because it allows simulation of large hydro system with a relatively high degree of detail, the EMPS model is deemed well suited for comprehensive studies on a national or international scale.

The EMPS model consists of two parts:

- A *strategy evaluation part* computes regional decision tables in the form of expected incremental water values for each of a defined number of aggregate regional subsystems. These calculations are based on use of a stochastic dynamic programming (SDP)-related algorithm for each subsystem, with an overlaying hierarchical logic applied to treat the multi reservoir aspect of the problem.

- A *simulation part* evaluates optimal operational decisions for a sequence of hydrological years. Weekly hydro and thermal-based generation is in principle determined via a market clearance process based on the incremental water value tables calculated for each aggregate regional subsystem. Each region's aggregate hydro production is for each week distributed among available plants using a rule-based reservoir drawdown model containing a detailed description of each region's hydro system.

Time resolution for the water balance equations in the model is 1 week, with demand represented by a stepwise duration curve within each week. Exogenously given import/export prices are also specified for each time step within the week. E.g. German prices are much higher during peak hours than during low load periods.

The system model

In the EMPS model the modelled interconnected power system is divided into regional subsystems, as shown in Figure I-1. Subsystem division may be based on hydrological or other characteristics of the local hydro systems, bottlenecks in the transmission systems, or it may be based on system ownership (one may e.g. want to explicitly model certain large producers, etc.).

Figure I-1 shows a model of the Nordic electrical system, with a varying number of subsystems representing each country. Norway, almost 100% dependent on hydropower, is represented by 12 subsystems. Sweden, with a mixed hydro-thermal system (roughly 50 % hydro on average), is modelled by five regional subsystems.

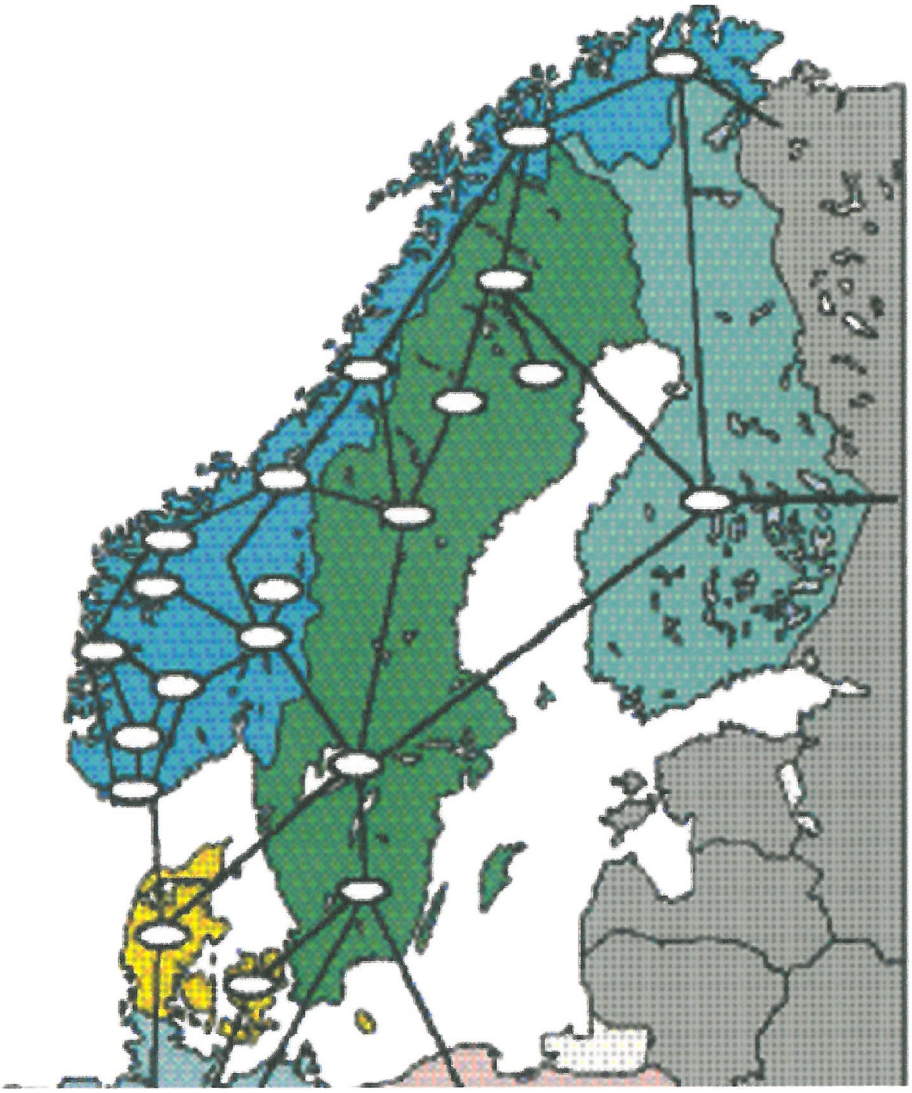

Figure I-1: A model of the Nordic power system in the EMPS model

Within each subsystem hydropower, thermal power and demand (either firm power demand or spot demand) may be modelled, as illustrated in Figure I-2. In addition the transmission system between subsystems is modelled with defined capacities and linear losses. Transmission fees for transport of energy may be modelled.

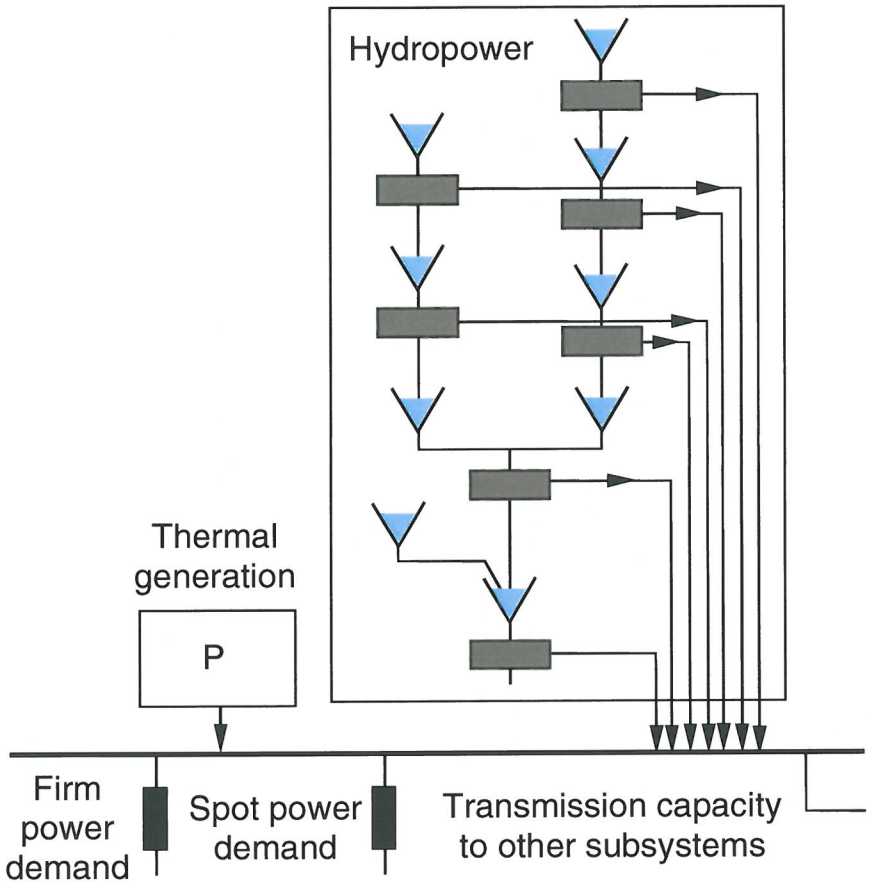

Figure I-2: Subsystem description.

The **hydropower system** within each regional subsystem may be modelled in detail. Based on standard plant/reservoir modules as shown in Figure I-3, even large and complicated river systems may be modelled. A model of the Norwegian hydro system may e.g. involve from 500 to 800 plant/reservoir modules, depending on the degree of detail.

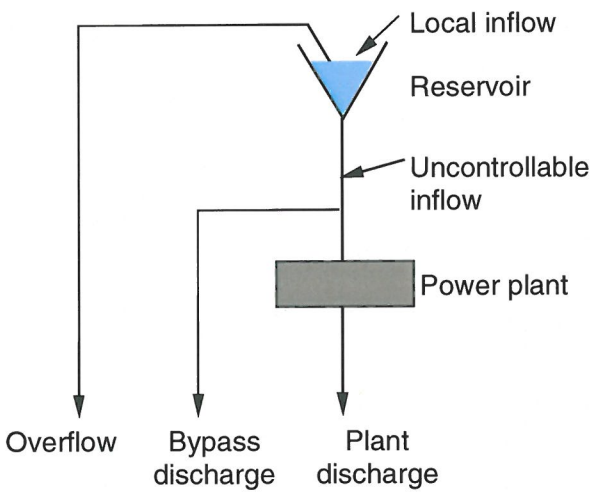

Figure I-3: Standard plant/reservoir module.

The following properties may be attached to each plant/reservoir module:

- a reservoir, defined by its volume and relationship between water volume and elevation,
- a plant, defined by its discharge capacity and a piecewise linear relationship between discharge and generation (generation is also corrected for variations in water head, but head is not included in the optimization problem),
- different destinations for plant discharge, bypass discharge and reservoir overflow (spill),
- variable constraints on reservoir contents and water flow (plant and bypass discharge),
- pumping capability, either reversible turbines or dedicated pumping turbines.

Thermal generation units are usually defined by their variable costs (based on fuel costs, etc.) and capacity. Both costs and capacity may be functions of time, so scheduled maintenance may be included. The expected availability of thermal units may be included by constructing an expected incremental cost curve (EIC) for each time step to represent available thermal units.

Typical of some fossil-fuelled plants, however, is that they are contractually or otherwise bound to receiving a specified inflow of fuel. This is particularly the case with gas-fired plants. The fuel inflow may be specified continually, or e.g. annual or pluriannual volumes may be specified. Thermal units bound by this type of constraint on fuel inflow are either modelled by fixed energy series injected directly into the power system (specified energy volume per week, no local fuel storage) or by equivalent hydro plants. The latter may be used both in the case where local fuel storage is possible, and in the case where fuel volumes are specified only for longer periods of time, e.g. annually.

Power demand may be either *firm* demand, which has limited or no price elasticity other than that implied by a curtailment cost function, and *spot demand.*

Firm power demand is modelled as specified energy consumption week by week, power variations within the week being modelled by a stepwise duration curve. Firm demand may be defined as having a defined price elasticity (demand increases when prices are low, and decreases when prices are high). Firm demand which is not price elastic is tied to a curtailment function. Inability to deliver non-elastic firm power entails buying curtailment power, presumably at a high cost.

Spot demand within each subsystem is modelled as a stepwise price-quantity relationship for each week, as shown in Figure I-4. There may be a duration curve for capacity and/or price. This marked consists mainly of electric boilers, and some industrial consumption. As figure 4 illustrates, curtailment power and thermal generation capacity (assuming fuel can be purchased and used as needed) are modelled principally in the same way as spot power demand.

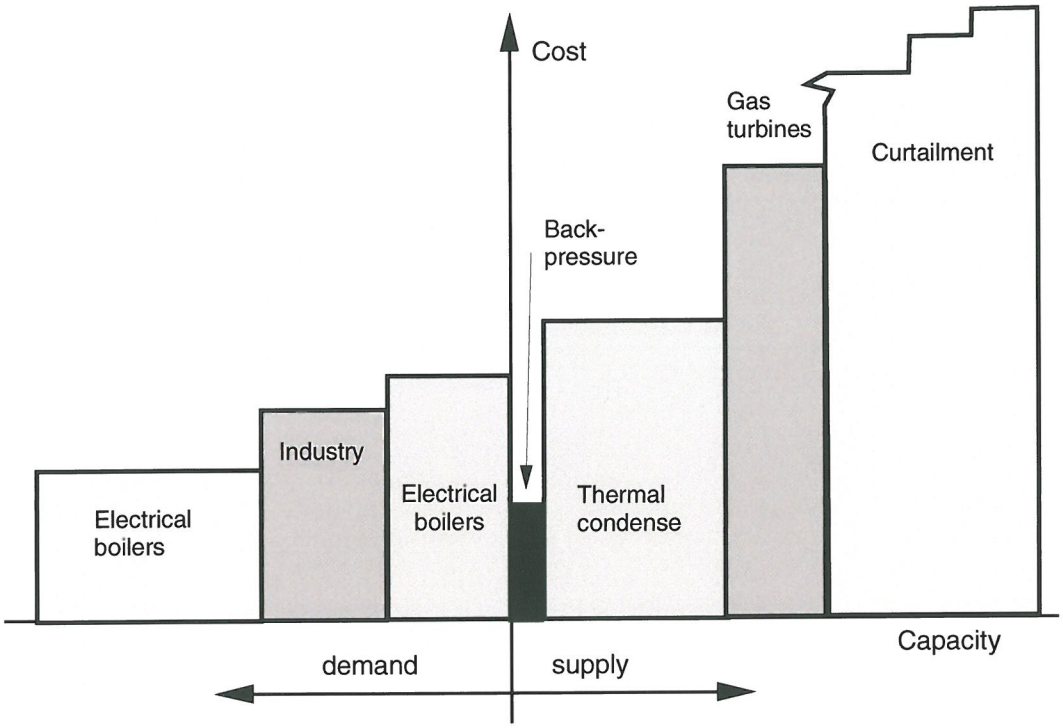

Figure I-4: Spot power market, thermal capacity and curtailment costs for a specified week.

Power exchange between countries, or between any interconnected subsystems for that matter, may be spot exchange or contractually fixed exchange:

- Optimal *spot exchange* between subsystems is one of the results of the market clearance process in the EMPS model, given by incremental power costs and transmission capacity, losses and fees. Transmission fees in the model might in fact not be fees at all, but instead be the profit required by one country or subsystem before being willing to export power to another subsystem. Or it could be a totally fictitious "fee" used simply to limit spot exchange, e.g. to limit annual power imports.

- *Contractually fixed exchange* between subsystems is modelled as firm power demand in the exporting subsystem, and as a fixed energy inflow injected into the importing subsystem. Transmission capacities for spot exchange would have to be modified to take into account the transmission of contractually fixed power.

The EMPS model strategy part

To limit the computational burden, the strategy part of the EMPS model is forced to utilize an aggregate model representation of the hydro system within each regional subsystem, i.e. an aggregate energy reservoir with an equivalent power plant and energy time series for storable and non-storable inflow. Otherwise the subsystem models are as indicated earlier.

Given the stated multi reservoir model description, the objective of the long term optimization process is to establish an operation strategy that for each stage in time (week) produces the best decision vector, given the system state at the beginning of the stage. By "best" decisions is understood the sequence of turbined and spilled water volumes that contribute to minimizing the

expected operational costs during the period of analysis. By system states is understood regional reservoir storage levels and per stage hydrological inflows. The stated problem from optimal control can in principle be solved by stochastic dynamic programming described by the recursive equation:

$$\alpha_t^*(X) = \underset{A_t U_t}{E\,Min}(C_t(U_t) + \alpha^*_{t+1}(X_{t+1})) \qquad (2)$$

t	:	index of stage
X	:	state vector at the beginning of stage *t*
$\alpha_\tau^*(X)$	:	expected value of the operation cost from stage t to the end of the planning period under the optimal operation policy
A_t	:	the distribution of inflow volumes A_t
E{}	:	represents 'expected value'
U_t	:	decision vector for stage *t*
$C_t(U_t)$	:	immediate cost associated with decision U_t

The solution of (2) requires the definition of discrete states. The number of such states increases exponentially with the number of state variables in the problem. Thus formal SDP-solution becomes infeasible when the number of reservoirs exceeds 2 - 3.

For practical solution of the multi reservoir decision problem an approximate methodology is employed in the EMPS model. An SDP-related algorithm is used as the nucleus for solving each regional subproblem, and an overlaying hierarchical logic is applied iteratively to treat the multi reservoir aspect. The process is illustrated in Figure I-5:

- A regional decision table in terms of incremental water cost is first calculated for each subsystem decoupled from the others. A version of backward SDP referred to as the *water value method* is used to this end.
- Simulation of total system behaviour is next performed using the computed decision tables to determine energy generation in each subsystem, energy exchange between subsystems and transactions with neighbouring countries.
- Feedback is then executed conditionally: If a stable and satisfactory solution is found, the process is terminated. If not, the result from the simulation is used to adjust regional premises, and return made to regional decision table computation.

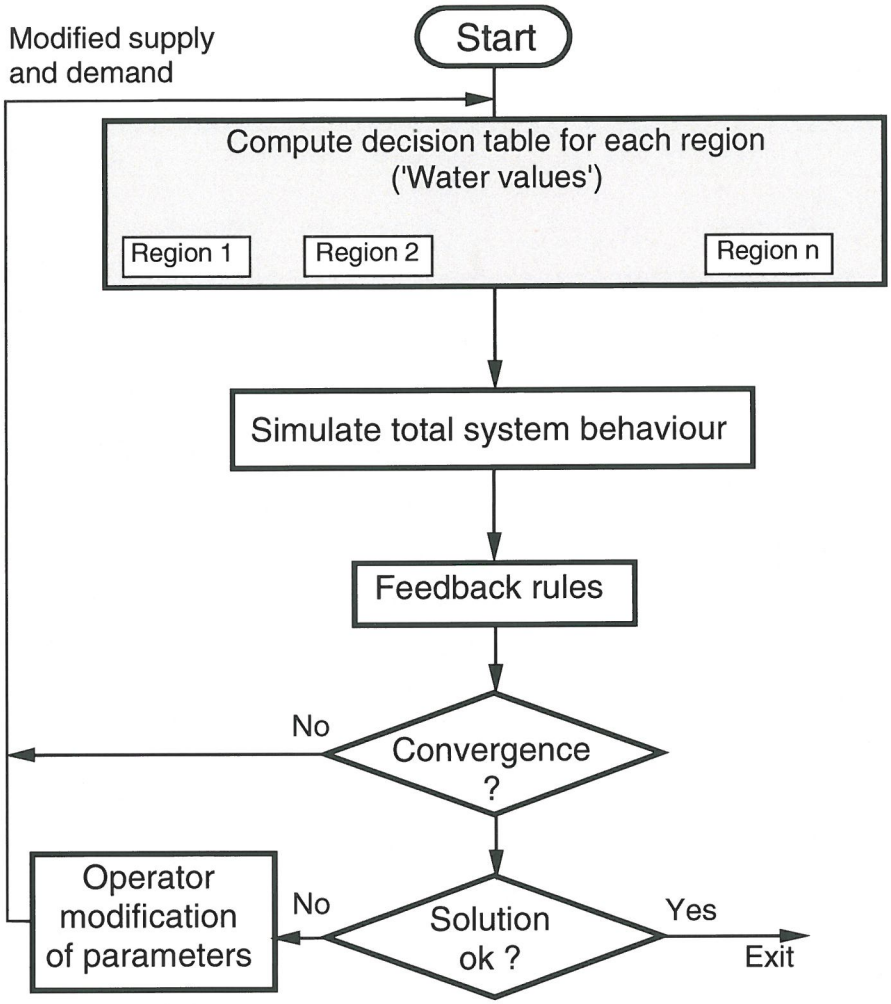

Figure I-5: Main logic for solving the multi reservoir problem.

While the EMPS model at most allows a planning horizon of 10 years, it is necessary to start calculation of incremental water values much further ahead in time (up to 20 years, depending on the size of the equivalent reservoir compared to annual inflow). This is in practice achieved through an iterative procedure, where water values are recomputed for the last year of the planning period until water values at the beginning of the last year are equal to water values at the end of the last year for all reservoir states. This is equivalent to regarding the modelled system as a static system from the beginning of the last modelled year and into the infinite future. The water value calculations are in principle started exactly far enough ahead in time so that the initial endpoint values at that point in time do not influence the resulting water values for the period being modelled.

The EMPS model's simulation part

In the simulation part of the EMPS model system performance is simulated for a chosen sequence of hydrological years. Based on the incremental cost tables calculated previously for each aggregate regional hydro system, weekly operational decisions on power generation (hydro or thermal) and consumption are made in what can be termed a market clearance process. A detailed rule-based reservoir drawdown model affords the distribution of each subsystem's aggregated

hydro generation among available plants for each level of demand each week. Historical inflow series covering a period of typically 60 years are the basis for simulation.

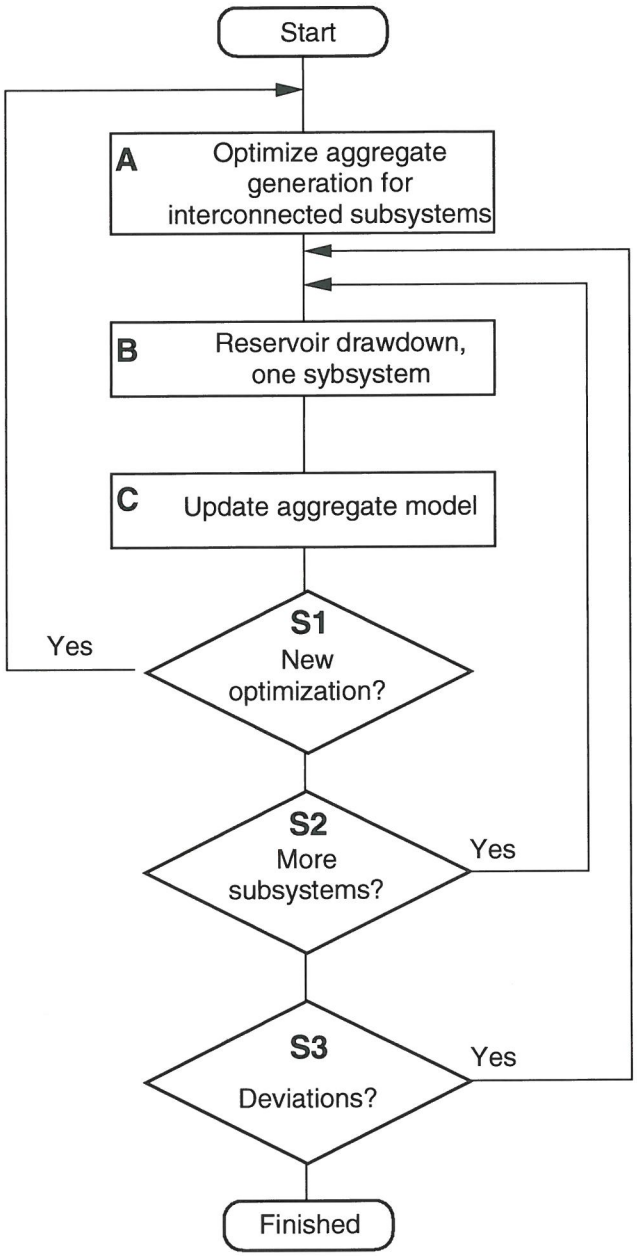

Figure I-6: The weekly decision process in the EMPS model's simulation part.

Figure I-6 illustrates the weekly operational decision process, summarized in the following points:

A *Optimize regional (aggregate) generation*
The optimum aggregate hydro generation is calculated, along with optimal thermal generation, consumption and exchange, given modelled incremental costs, capacities, losses and constraints. Hydro power is modelled as an aggregate equivalent reservoir, and an aggregate plant with a piecewise constant efficiency rate as well as a piecewise constant operational cost. This cost is added to the incremental value of stored energy.

B *Reservoir drawdown*
A detailed reservoir drawdown model affords the distribution of aggregate generation among available plants, and thus the distribution of stored energy among available reservoirs, according to a rule-based strategy. When detecting an active constraint which increases costs of generation by more than 5%, the model exits temporarily B for an update of the aggregate hydro plant description in C, and recalculation of optimum generation in A, before returning to B for continuing the reservoir drawdown process.

C *Update equivalent model*
Upon exiting the reservoir drawdown model, the aggregate hydro model is always updated with the latest inflow, active generation constraints, pumping and plant efficiency. If this modifies the aggregate model in any way, optimum generation is recalculated by returning to A.

S1 *New optimization?*
The model returns to A for a new optimal decision whenever the equivalent hydro model has been modified, or if reservoir drawdown calculation is interrupted before completion.

S2 *More subsystems?*
Reservoir drawdown is performed for one subsystem at a time, and is repeated for all subsystems that have a local hydro system modelled in detail.

S3 *Deviations in hydro generation?*
Because the subsystem models are updated as the reservoir drawdown process progresses, there will often be a deviation between the optimal generation calculated in A and the resulting hydro generation from B after the first try. Causes of deviation may be changes is other subsystem equivalent models after reservoir drawdown for a subsystem is completed, changes in head, and changes in consumption from reversible turbines. The whole process may be repeated a number of times, in an attempt to reach the closest possible conformity in hydro generation between A and B.

The disaggregation of regional subsystem storage into individual reservoir storage and subsystem hydro generation into individual plant generation is afforded by a detailed reservoir drawdown model which utilizes a rule-based logic for reservoir depletion. This model has two types of reservoirs:

- Buffer reservoirs, whose operation is defined by guide curves. These are mainly reservoirs with low storage capacity in relation to inflow, e.g. run-of-the-river type).
- Regulation reservoirs, which are operated according to a general reservoir drawdown strategy.

The basic goal of the reservoir drawdown strategy is to produce a specified amount of energy in such a way as to minimize expected future operational costs. This goal is sought fulfilled by:

1. seeking to minimize risk of overflow during that part of the year when inflow is greater than discharge.

2. seeking to avoid loss of power capacity caused by empty reservoirs during that part of the year when discharge is greater than inflow.

In the Nordic countries this implies dividing the year into a *filling* season (late spring, summer and early fall, with high inflow and low power consumption) and a *depletion* season (late fall, winter and early spring with low inflow and high power consumption).

Results that may be extracted from a system simulation in the EMPS model include:

- hydro system operation (reservoirs, flows, generation, pumping),
- thermal generation,
- power consumption, curtailment,
- exchange between subsystems,
- economic results,
- electricity-related emission figures,
- incremental benefit figures of increasing the capacity of various facilities (hydro, thermal, transmission system).

APPENDIX II DEMAND PROFILES

This section documents how we have calculated new relative demand factors for general demand for different segments within a week and for different weeks within a year. This is important input to the EMPS model and the values have large influence on the estimated peek load values for different years.

Hourly general demand

In a previous project reported in [1] we organised data for hourly consumption in Norway (1989 – 2002) and Sweden (1996 – 2002) from Nord Pool (24*365 continuous values per year) into hourly consumption within 52 calendar weeks for each year (168*52). Our data for hourly demand in different weeks in a given year typically have some registrations for the previous calendar year or for the next calendar year since January 1st seldom is day 1 in week 1. Moreover, some registrations at the end of each year is typically neglected since 52 weeks only is 364 days.

The total consumption in any given hour include demand from all sectors, including general demand, industry, boilers and pumping, and hourly demand registrations for each sector is not available. However, the monthly statistics from Statistics Norway (SSB) shows that power consumption in power intensive industry is relatively constant over the year except for a slight decline during the summer. We do not take this variation into account when we calculate the demand profiles and we assume constant consumption for industry and boilers. Hourly demand for industry and boilers in different years is calculated by dividing annual consumption for industry and boilers in different years by the number of hours in a year. Numbers for annual consumption is taken from Statistics Norway and Statistics Sweden

In Norway there is considerable pumping to reservoirs during the summer, and the pumps use electricity. We assume that the pumping occurs only in weeks 19-44 and that the electricity consumption used for pumping is the same for all hours in that period. The annual consumption used for pumping is taken from Statistics Norway.

Now we can estimate the hourly general demand by subtracting the calculated hourly demand for industry, boilers and pumping from total hourly demand registrations from Nord Pool. See [1] for detailed references and for more details about calculations of hourly general demand for 52 week years.

Relative hourly demand within a week

In the EMPS model one profile for the within-week variation for general demand is specified for each area, and in our dataset the same profile is used for all Norwegian areas. The profile identifies the typical within-week load variation for normal temperatures. The simulated load will however be different since each stochastic outcome has a specific temperature correction for the demand for each week. In the following we explain how we have calculated the within-week profiles for Norway and Sweden on basis of the calculated hourly general demand.

Firstly, the calculated hourly general demand is normalised so that the annual average is 1. The corresponding relative demand figures are called Per Unit (PU) values. The PU values are used in the following since we are interested in the typical *relative* demand profile.

The within-week profile is important for the forecasting of the hourly peak load and therefore for the valuation of load shifting. We have therefore focused on winter weeks (week 49 to week 9). Thus, for each year, we have 13 registrations for each hour within the week in our dataset, e.g. for the 1st of 168 hours. For Norway we have registrations for 14 years and for Sweden we have registrations for 7 years. Thus, for Norway, we have 13 (weeks) * 14 (years) = 182 registrations for each hour within the week, and the average PU value is calculated.

The calculated PU values are larger than 1 since the average general demand in week 49 – week 9 is larger than the annual average. This is not a problem since only the relative demand between different segments within the week has importance for the simulated demand. Still, to make the results more intuitive, we normalized the within-week average PU value to 1. The resulting within-week averages are illustrated in Figure II-1.

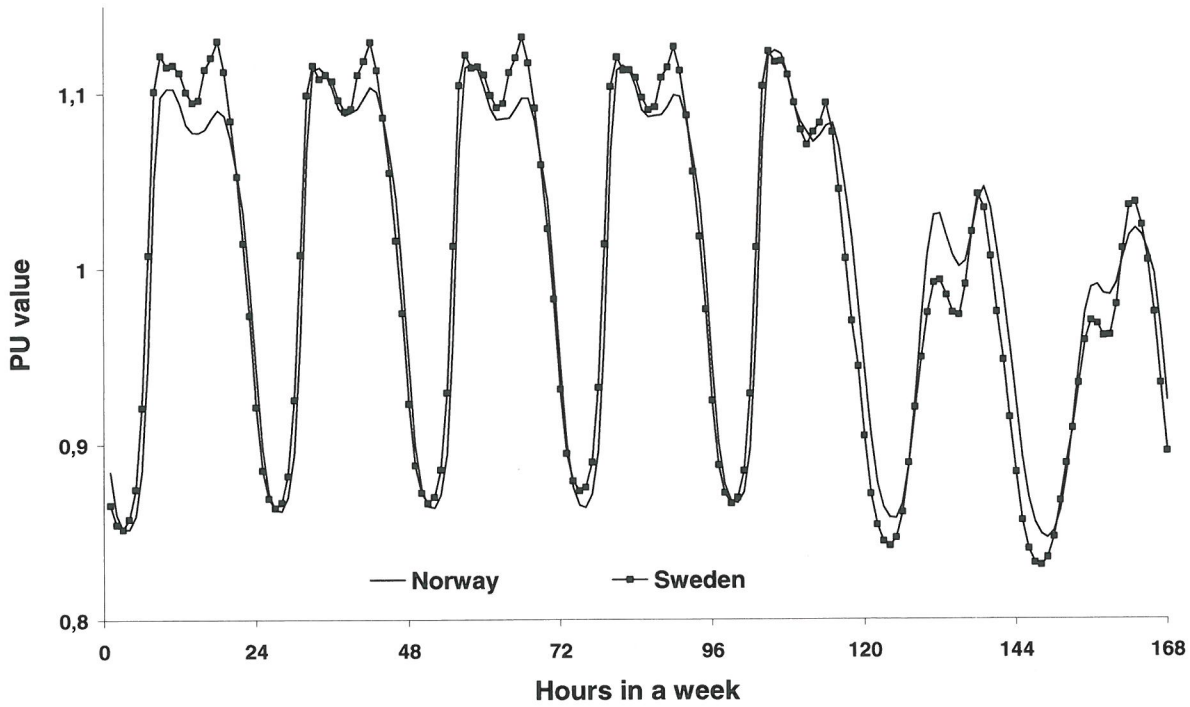

Figure II-1: Average PU values within a week. The average is calculated for week 49 – week 9 and for the years 1989 – 2002 for Norway and for the years 1996 – 2002 for Sweden.

In our dataset for Sweden in the EMPS model we simulate several areas but we do not have any information about the size of industrial demand in each area. All demand is therefore interpret as general demand for Sweden in that dataset. Since the demand for industry is relatively constant we cannot use the calculated relative demand profile for general demand for all demand types.

Thus we had to calculate a new relative demand profile for Sweden where we assumed that all consumption was general demand in the calculations. The revised within-week profile for Sweden is illustrated in Figure II-1.

Modelled within-week load factors

Norway and Sweden

Several within-week segments can be defined in the EMPS model. Still we have to summarize the 168 hours with e.g. 8 periods where each period can represent several hours. By visual inspection of Figure II-1 and the underlying dataset we identified 3 possible peak load hours for our simulations. In Norway the relative demand is highest during the morning peak at 10 am (i.e. 9 am – 10 am), while the relative demand in Sweden is highest for during the afternoon peak at 6 pm. The peak for the sum of the PU values for Norway and Sweden is however 9 am. In simulations, each of these three hours are possible peak loads in the Nordic system since the weekly temperature correction for demand is different for Norway and Sweden. Thus, we have a within-week period for each of these hours. The 6 pm hour at Friday (hour 114) is however not included in the Swedish peak load period since the Friday peak is lower, cf. Figure II-1. The other within-week periods were made to account for most of the within-week hourly variation. For each within-week period we calculated the average PU value for the included hours. The resulting periods with corresponding PU values, lengths and hours represented by each period is shown in Table II-1.

Table II-1 Within-week load segments

No	Period name	PU value		Length (hours)	Represent the following within-week hours
		Norway	Sweden		
1	Nordic high	1.112	1.121	5	9, 33, 57, 81, 105
2	Norwegian high	1.115	1.114	5	10, 34, 58, 82, 106
3	Swedish high	1.097	1.129	4	18, 42, 66, 90
4	High day	1.099	1.111	20	11, 35, 59, 83, 107, 12, 36, 60, 84, 108, 17, 41,65, 89, 113, 19, 43, 67, 91, 115
5	Low day	1.072	1.077	41	8, 32, 56, 80, 104, 13, 37, 61, 85, 109, 14, 38, 62, 86, 110, 15, 39, 63, 87, 111, 16, 40, 64, 88, 112, 20, 44, 68, 92, 116, 21, 45, 69, 93, 117, 22, 46, 70, 94, 118, 114
6	Night	0.905	0.910	45	1, 25, 49, 73, 97, 2, 26, 50, 74, 98, 3, 27, 51, 75, 99, 4, 28, 52, 76, 100, 5, 29, 53, 77, 101, 6, 30, 54, 78, 102, 7, 31, 55, 79, 103, 23, 47, 71, 95, 167, 24, 48, 72, 96, 168
7	Week-end day	0.995	0.980	30	128, 152, 129, 153, 130, 154, 131, 155, 132, 156, 133, 157, 134, 158, 135, 159, 136, 160, 137, 161, 138, 162, 139, 163, 140, 164, 141, 165, 142, 166
8	Week-end night	0.886	0.865	18	119, 143, 120, 144, 121, 145, 122, 146, 123, 147, 124, 148, 125, 149, 126, 150, 127, 151

The corresponding duration curves for Norway and Sweden is illustrated in Figure II-2. The 3 peak hours periods "Norwegian high", "Nordic high" and "Swedish high" are on the left in Figure II-2 followed by "High day", "Low day", "Week-end day", "Night" and "Week-end-night", but the order for the three first periods are different for Norway and Sweden.

The within-week peak loads are relatively higher for Sweden than for Norway even though the duration curve for Sweden includes demand from all sectors. The reason for the sharper profile in Sweden can be that a relatively larger share of the electricity is used for space heating in Norway, and the need for heating does probably not have a very sharp 24-hour profile compared to other needs covered by electricity such as lighting and electrical machines. The profiles would probably be different if we had used data for the summer weeks to calculate the within-week profile since the need for heating is less during the summer.

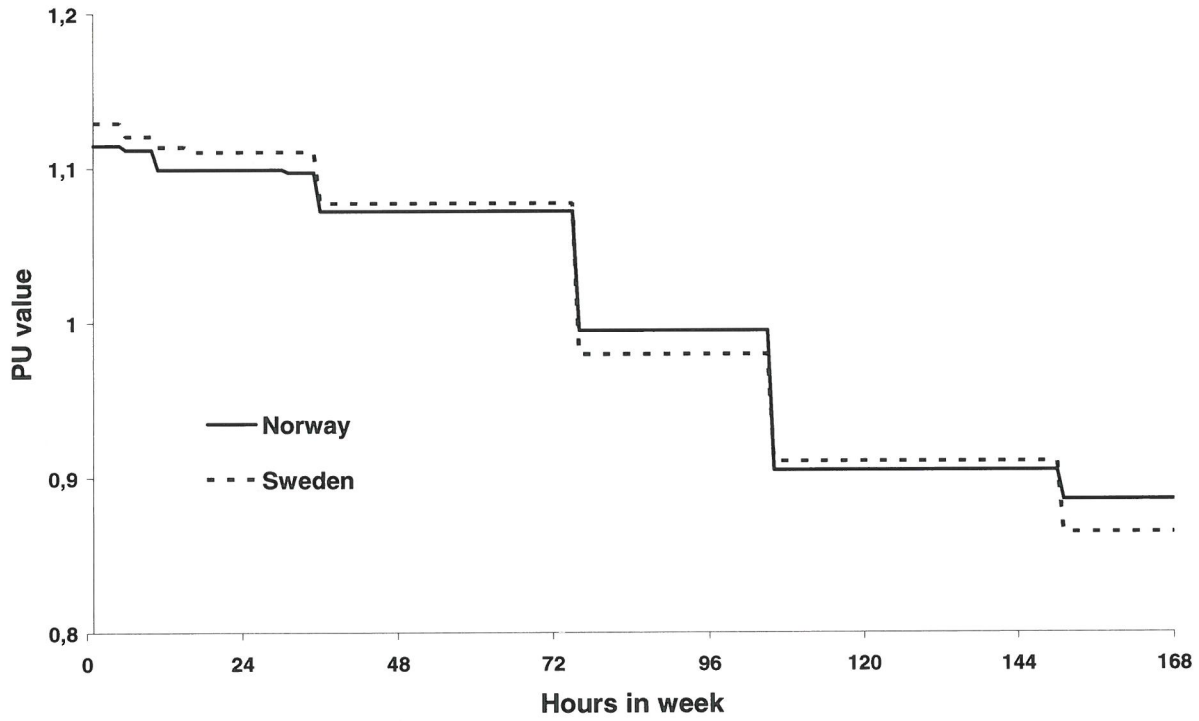

Figure II-2: Modelled duration curves for the relative electric load within a week in Norway and Sweden (general demand in Norway)

Finland and Denmark

For Finland and Denmark we do not have hourly registration of demand available at present. Thus we base our calculations on existing input data in the EMPS model but converted from 7 to 8 within-week periods. The resulting within-week duration curve is shown in Table II-2 and illustrated in Figure II-3.

Table II-2 New load profile for Denmark and Finland

No	Period	Denmark	Finland
1	Nordic high	1.239	1.071
2	Norwegian high	1.239	1.071
3	Swedish high	1.239	1.071
4	High day	1.239	1.071
5	Low day	1.091	1.045
6	Night	0.881	0.963
7	Week-end day	0.925	0.969
8	Week-end night	0.765	0.908

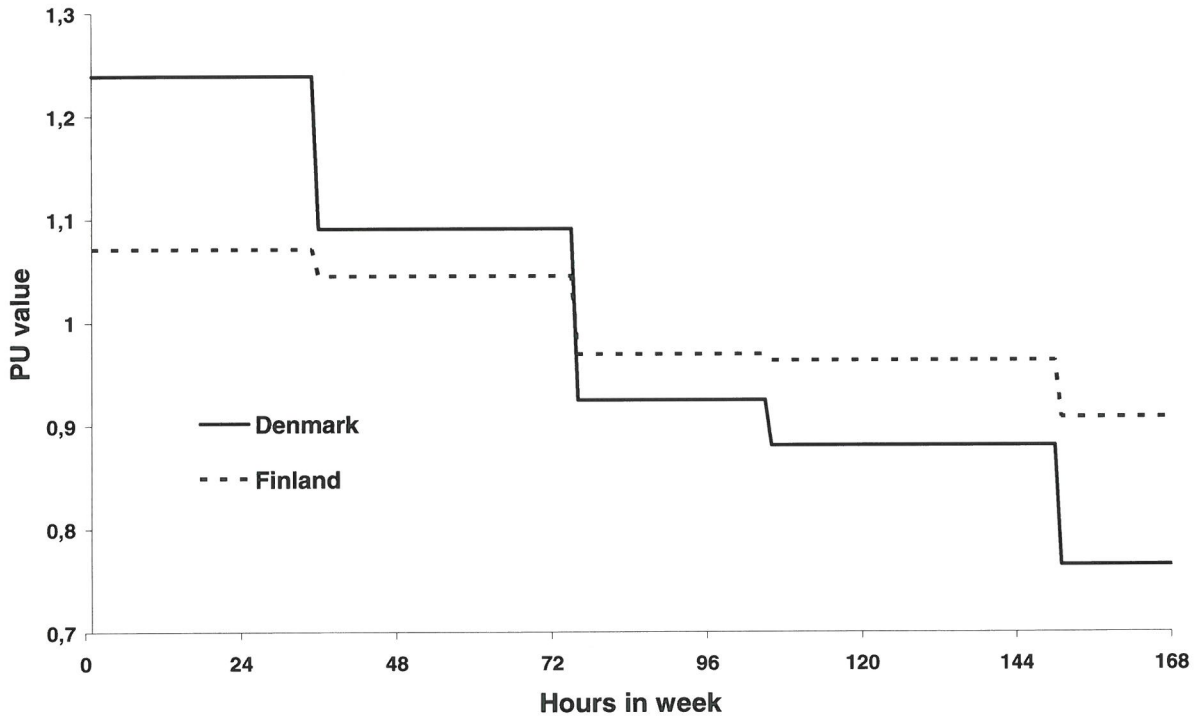

Figure II-3: Modelled duration curves for the relative electric load within a week in Denmark and Finland

Other segment profiles

Some within-week profiles are defined also for other units for Sweden, Denmark and Finland. The existing values for "Høy dag" is used for "Nordic high", "Norwegian high", "Nordic high" and "high day", values for "Lav dag" is used for "Low day", values for "Natt" is used for "Night", values for "Helg" is used for "Week-end day" and values for "N-lør" is used for "Week-end night". The existing values for "Høy kveld" and "N-søn" are identical to "Høy dag" and "N-lør" respectively.

Average relative demand per week within a year

In the EMPS model one profile for the within-year variation is specified for each area. In the following we explain how we have calculated these profiles.
Norway

The used hourly demand registrations is for whole Norway, so it is not straightforward to use these data to make weekly load coefficients for different areas within Norway. Instead we used Nord Pool registrations for weekly general demand in 4 Norwegian areas available for the years 1997 – 2002. For each region the relative demand values for each week is calculated by dividing the weekly demand by the annual mean value for that area. Now we could calculate the load factor for a particular week as the average relative demand for that week in the years 1997 – 2002, but we wanted to include data for more years.

The weekly data for general demand in 4 regions in 1997 – 2002 was used to calculate each region's average share of total general demand in Norway for each week. We assume that the calculated shares for 1997 – 2002 are valid also for 1989 – 1996. The hourly data for total general demand in Norway was used to calculate total general demand in different weeks in each year 1989 – 1996. Now we estimated the general demand in each region, week and year for 1989 – 1996 by multiplying the total general demand for Norway for that week and year by the share for that region and week. The corresponding relative demand factors for different weeks in different years were calculated for each region and years 1989 – 1996. The resulting PU value for a particular week is the average of the PU values for the years 1989-2002. Values for 4 Norwegian regions are illustrated in Figure II-4.

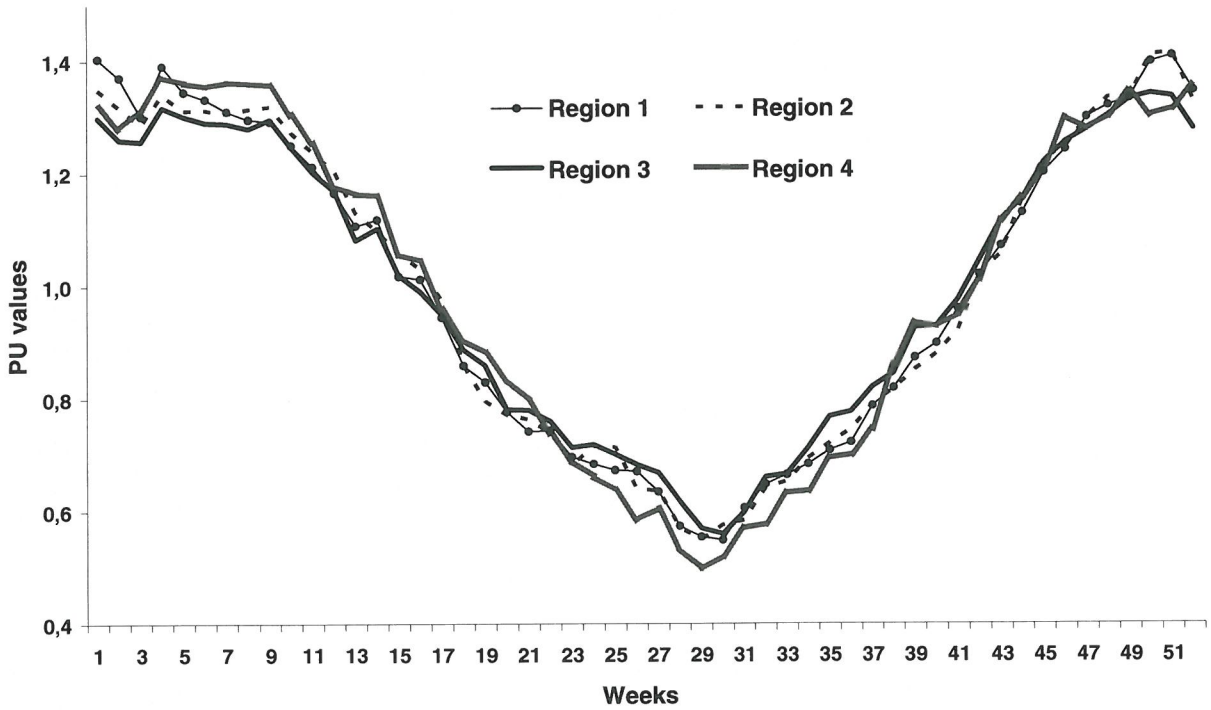

Figure II-4: Load factors for different weeks for 4 Norwegian regions.

Sweden

For Sweden we used the data for total hourly consumption in different weeks. The hourly demand was summarised for each week. The relative demand values for each week is calculated by dividing the weekly demand by the annual mean value, and the modelled load factor for a particular week is the average relative demand for that week in the years 1996 – 2002. The corresponding load factors for different weeks are illustrated in Figure II-5.

The annual load profile is sharper for the Norwegian regions than for Sweden. The reason for this is probably that a larger share of electricity for heating in Norway. The electricity demand is therefore relatively high during the winter. Moreover, the Norwegian profile is only for general demand while the Swedish curve represents the profile for the total demand.

Denmark and Finland

For Denmark and Finland we used the existing input data in the EMPS model. Normalized values are illustrated in Figure II-5.

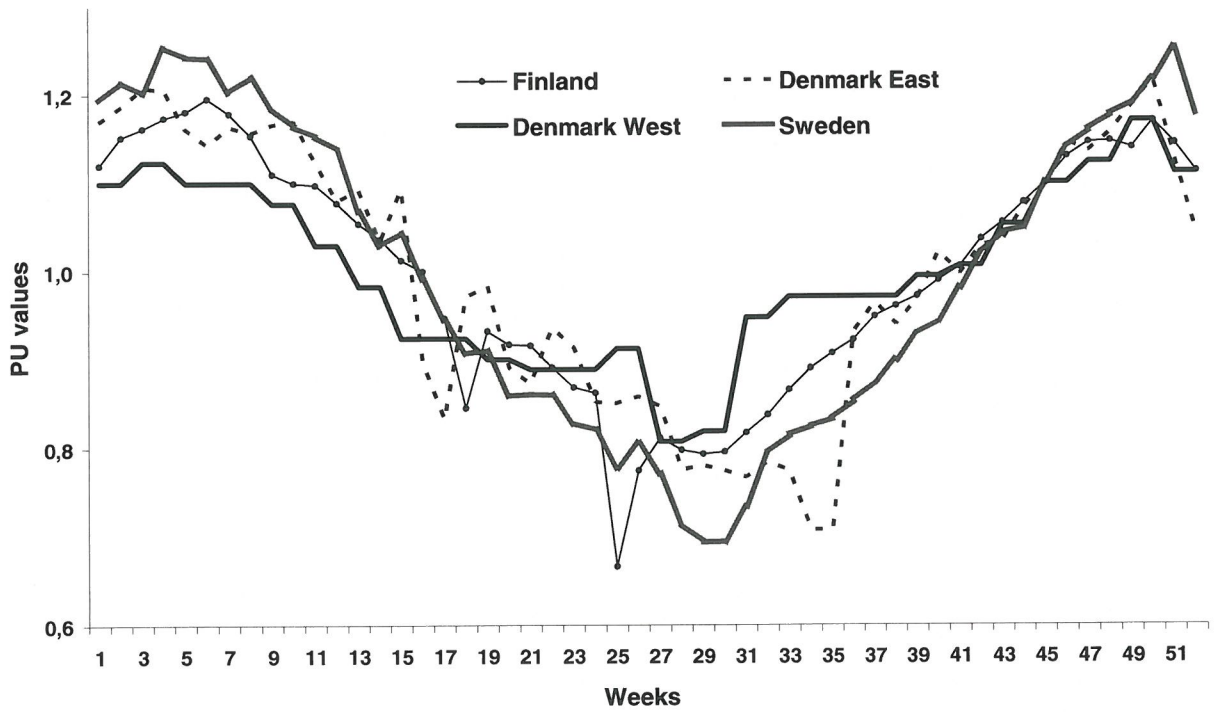

Figure II-5: Load factors for different weeks for Sweden, Finland, Denmark East and Denmark West.

APPENDIX III ADJUSTED SOCIAL SURPLUS

In the typical case the socio-economic surplus can be calculated as the area between the demand curve and the supply curve, and this corresponds to consumer surplus (area between demand curve and price) plus producer surplus (area between price and supply curve / marginal cost curve).

To implement a shift in demand, we cannot modify the relative demand profiles directly because this would result in a *relative* reduction of demand and not an *absolute* reduction. Neither can we define negative demand directly, but we can do so by defining corresponding generation. We therefore implemented reduced demand in the peak load periods in the model by including a new generation unit that offers the reallocated amount no matter how low the price is. This has the same effect as decreasing demand, but the calculated socio-economic surplus must be corrected correspondingly. Why and how is described subsequently.

We have reallocated demand from peak load periods to the Low day period. The socio-economic surplus is increased in the Low day period since the demand has shifted towards the right so that the demand is larger for all prices. On the other hand the socio-economic surplus will be lower for the peak load periods since we have reduced the demand in these periods. But since we have "cheated" and implemented the reduced demand as an additional supply the socio-economic surplus is increased for these periods too in the model simulations. In the following we will show that it is straightforward to do the necessary adjustment of socio-economic surplus.

We start by considering how much the socio-economic surplus changes if we increase demand *and* supply within the same period, cf. Figure III-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 demand 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 demand 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.

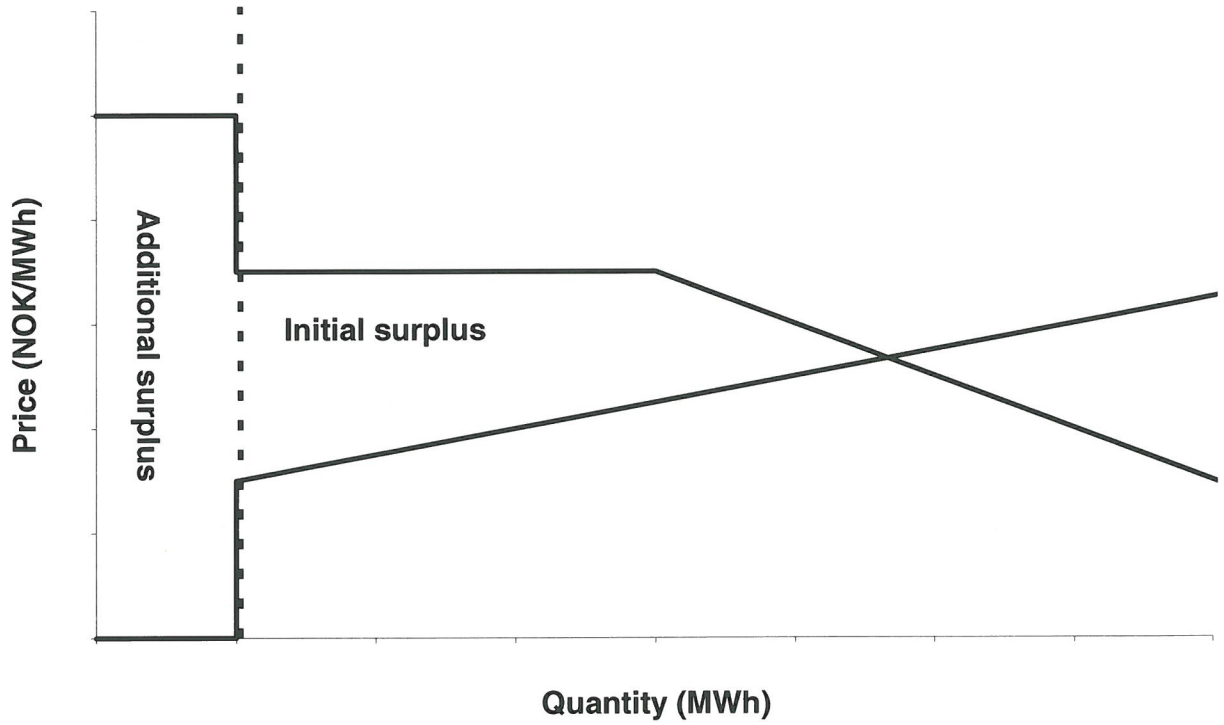

Figure III-1: Increased socio-economic surplus for an additional demand with marginal value above rationing cost and a corresponding increase in supply at zero costs.

Figure III-2 shows the socio-economic surplus after demand has 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 shows 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 area **A+B+C**.

Figure III-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 period 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 shows the initial situation while the dotted lines shows how demand and supply changes in the two periods. Note that the right shift for the supply curve in Figure III-3a (the horizontal distance between the solid and the dotted curve given by "Δ") is the same as the left shift for the demand curve in Figure III-2a and the right shifts for the demand curves in Figure III-2b and Figure III-3b.

The total socio-economic surplus in Figure III-3 after demand has been reallocated with our methodology is **D+E+F+G+H+I+J**. If the thick grey line had been the vertical axis in Figure III-3a, the demand curve had shifted by the reallocated amount compared to the initial situation. Thus, the demand curve seen from the grey vertical line towards the right is identical to the dotted demand curve in Figure III-2a. Moreover, the dotted supply curve in Figure III-3a is identical to the initial supply curve used in Figure III-2a seen from the grey vertical line towards the right. Thus, seen from the grey line towards the right, the solutions after the changes are

identical in Figure III-3a and Figure III-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 III-3, we get **A+B+C+D+F+J.** The difference in the socio-economic surplus in Figure III-2 and Figure III-3 is therefore **D+F+J**, which is the area marked as "Additional surplus" in Figure III-1. Fortunately this amount is a constant and given by

$$6000 \text{ MWh/week} \cdot 52 \text{ weeks} \cdot (375+1) \text{ Euro/MWh} = 117.31 \text{ million Euro per year}$$

where 375 Euro/MWh is the rationing cost and 1 Euro/MWh is the additional value corresponding to the area **J**.

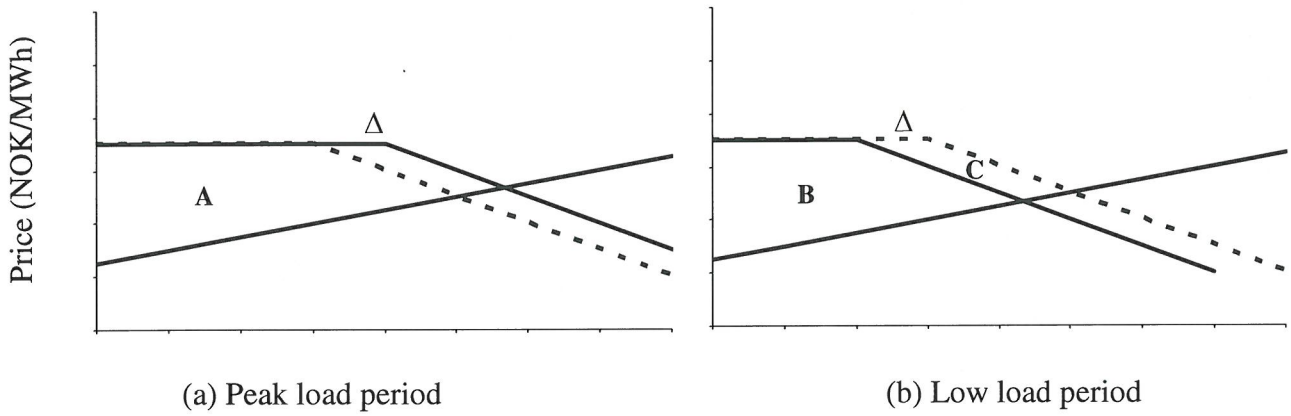

Figure III-2: Socio-economic surplus after reallocating demand by shifting the demand curve.

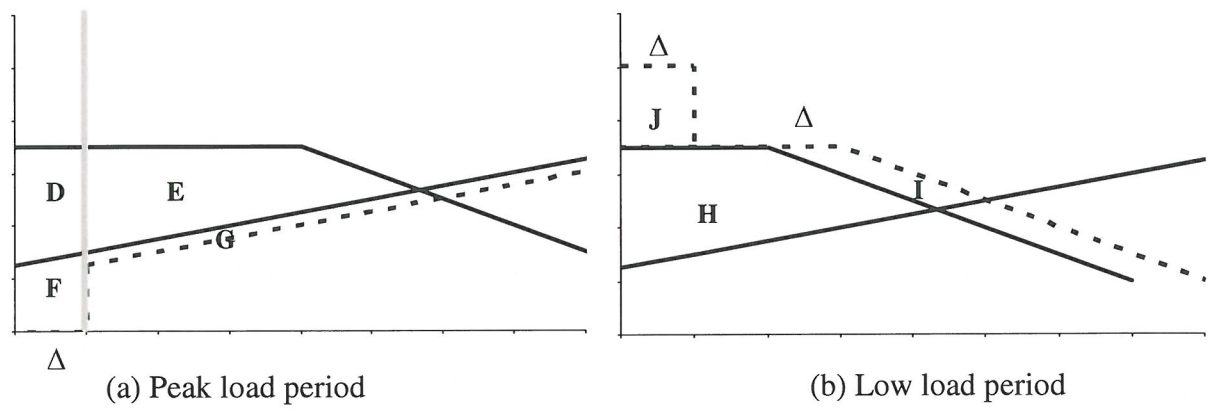

Figure III-3: Socio-economic surplus after reallocating demand with the described methodology.

SINTEF Energi AS
SINTEF Energy Research

No-7465 Trondheim
Telephone: + 47 73 59 72 00

energy.research@sintef.no
www.sintef.no/energy