E F F L O C O M

Energy efficiency and load curve impacts of commercial development in competitive markets

EU/SAVE 132/2001

Phase 2 – Influence of Competition on load curves

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Summary

The system loads from six countries: Denmark, Finland, France, Norway, Sweden and UK have been investigated to find possible similarities and differences in load patterns before and after deregulation. Typical load patterns and load profiles of different customer categories are also assembled. The customer load patterns are investigated and combined with system load to make hourly customer segmentations of the total load for each country during the year 2001, and also for earlier years dependent on country describing the typical consumption before deregulation. The database that holds all collected data is available through a web site: www.efflocom.com (password protected).

The main aspects of deregulation are:

- Unbundling of services into monopoly and competitive businesses
- Opening of the electricity market
- New structures for network tariffs
- Change of supplier options
- Change of ownerships

It is difficult to relate the registered minor changes to any of these main aspects.

There have been no basic changes in tariffs and other products since deregulation. However, investigation of the total system hourly loads before and after deregulation shows the following broad relationships:

Temperature sensitivity

No radical change has happened since deregulation of the markets in the investigated countries. Generally, Finland, Denmark and UK have the lowest temperature sensitivities; and Norway, Sweden and France have the highest. Sweden is the only country that has higher average sensitivities after deregulation compared to before.

All Norwegian and Swedish temperature sensitivities are more negative than the average. The deregulation of Norway seems to have lead to higher temperature sensitivity for all seasons and day-types, except summer and winter workdays. This can be explained by a growth of demand of the domestic sector.

Sweden seems to have another development – less temperature sensitivity in the cold season since deregulation, and higher sensitivities during summer. No clear explanation is found to account for this.

UK has a dramatic reduction of sensitivity of the winter season since deregulation, no clear explanation is found.

Regarding France, in 2001 the customers sensitive to weather conditions were not yet eligible to the market. In 2001, France has the highest temperature sensitivity in winter season. This can be explained by the fact that el. prices are relative low in France and by the development of electricity space heating since 1973 in response to the oil crisis. However EDF on the one hand has promoted a better insulation and the use of energy controllers and on the other hand has launched real-time tariff options (EJP, Tempo). These new options have disturbed the correlation between daily electricity consumption and temperature. Concerning summer the results are not significant and nothing can be concluded except that the influence of air conditioning is not yet visible.

For Finland we miss temperature data for a year before deregulation, so no sensitivity has been calculated for this reason. The sensitivities after deregulation are quite low, even though Finland is a cold country. This indicates use of non-electric space heating.

In 2001, Denmark has reduced sensitivities compared to year 1998. This might be explained by other reasons than deregulation since only 33% of the Danish consumption participated in the free market in 2001 (where 16% started 1. April 2000) – one of the reasons might be that the authorities of Denmark has taken measures to move away from using electric space heating the later years.

Development of Customer demand

No radical changes in peak load profiles and utilisation factors are found since deregulation. No radical changes are found in the distribution of annual energy consumption and maximum demand of different customer segments.

Peak load comparison before and after deregulation:

- Norway: Reductions of process Industry (after deregulation), higher share from public service. This can be explained by the state of the industrial market leading to lower activity in 2001.

- Sweden: Reduction of Industry activity at peak, but a higher share of domestic customers.

- Denmark: Nearly no changes in the peak load and energy shares before and after deregulation of 33% of the market.

- Finland: Greater share from Industry and the business sector after deregulation while the domestic customers has a lower share.

- It has not been possible to make a segmentation of the UK peak day, (lack of customer type profiles) but the peak day profiles before and after deregulation are not very different, indicating no radical changes in the consumption of customer types.

- No segmentation of the peak into customer groups has been made for France, due to lack of customer type profiles. The peak profiles show a growth of 10.5% during 1996 to 2001, and the growth seems to be equal for all hours. This indicates no radical changes in customer load patterns.

1 Aims of Phase 2

EU Directives specify that Electricity and Gas markets must be fully deregulated by June 2007. Many countries addressing this have decided to open their markets in phases starting with the largest customers. At this point countries are in different stages of market opening.

The aim of Phase 2 is to examine the impacts of deregulation on the load profiles for different customer categories and on a national or regional level. The examination will consider the tariff structures and settlement systems in place. Using load profile data provided by EFFLOCOM Phase 1, the load profiles available from each country are examined before and after deregulation, where applicable.

The year of implementation of deregulation for each country are displayed in Table 1.1 **Opening of markets** In the table "Year of deregulation" denotes the year of official opening of the electricity market in the country. This however does not mean that all customers from that year on can participate in the market, but a process would start where different market segments gradually gets access to the market.

Country	Year of deregulation
Norway	1991
UK	1989
Finland	1995
Sweden	1996
Denmark	1998
France	1999

Table 1.1 Opening of markets

2 *Electricity Trading Arrangements, Profile and Settlement Systems*

2.1 *Electricity Trading Arrangements in UK*

2.1.1 *Overview*

Wholesale electricity trading arrangements introduced in England and Wales in 2001 are designed to provide greater competition, while maintaining a secure and reliable electricity system. The new arrangements are based on bilateral trading between generators, suppliers, traders and customers, and include:

- forwards and futures markets that allow contracts for electricity to be struck over timescales ranging from several years ahead to on-the-day markets;
- a Balancing Mechanism by which the National Grid Company (NGC), the operator of the transmission system, accepts offers and bids for electricity close to real time to enable it to balance supply and demand; and
- an Imbalance Settlement process for making payments to and from those whose contracted positions do not match their actual metered electricity production or consumption and for clearing certain other costs of balancing the system.

2.1.2 *Details*

2.1.2.1 Introduction

This document provides a high level explanation of the New Electricity Trading Arrangements (NETA) introduced in England and Wales in March 2001. Full information on these arrangements is contained in the Balancing and Settlement Code (BSC) and supplementary BSC documentation, which can be downloaded from the BSC (ELEXON) website – www.elexon.co.uk.

2.1.2.2 The BSC Trading Arrangements

A principle of the design of the BSC trading arrangements is that electricity should be traded bilaterally between willing buyers and sellers at prices under terms agreed between the counter-parties. Trades are carried out primarily ‘Over the Counter’ (OTC) and on the Power Exchanges that have developed to support the arrangements. However, the characteristics of electricity mean it is almost inevitable that quantities of energy generated and consumed will deviate from the quantities for which contracts have been struck in advance. Consequently, central arrangements are required to: meter the quantities produced and consumed by each party; compare these with the quantities covered by bilateral contracts, and provide financial settlement for the differences (known as ‘imbalances’). These functions are collectively referred to as ‘imbalance settlement’.

The BSC trading arrangements are also required to provide an additional function, referred to as the ‘balancing mechanism’. The National Grid Company (NGC) as the Transmission Company has a licence obligation to manage the Transmission System and, in so doing, may anticipate that more energy will be generated than consumed, or vice versa. Unchecked, this would result in system frequency falling or rising to an unacceptable degree. The balancing mechanism provides a means by which NGC can buy or sell additional energy close to real-time to maintain energy balance, and also to deal with other operational constraints of the Transmission System. Specifically, the balancing mechanism allows BSC Parties (if they wish) to submit Offers to sell energy (by increasing generation or decreasing consumption) to the system and Bids to buy energy (by decreasing generation or increasing consumption) from the system, at prices of the BSC Party’s choosing.

These Offers and Bids may be submitted in respect of each unit of generation or consumption (known as a BM Unit) belonging to each BSC Party. NGC accepts Offers and Bids as necessary to balance the system and seeks to do so at least cost by taking the lowest-priced Offers and accepting the highest priced Bids consistent with factors such as transmission system constraints and the ability of BSC Parties to deliver within the timescales necessary. The 'cash-out' or imbalance prices – System Buy Price (SBP) and System Sell Price (SSP) – applied to imbalances are derived largely as the weighted average prices of these accepted balancing mechanism Offers and Bids.

2.1.2.3 The Balancing and Settlement Code

The trading arrangements and their governance are enshrined in the BSC. The requirement to have the BSC in force is placed on NGC through its Licence. It is a condition of a Generation and Supply Licence that licensees are bound by the BSC, and that they must become BSC Parties by signing the BSC Framework Agreement (which gives contractual force to the BSC). Other parties who are not licensees have the option to sign the BSC Framework Agreement, which affords them the right to notify energy contract volumes, register BM Units (if they are Interconnector Users or licence exempt) and exposes them to any charges and payments that result.

Overview of the Balancing and Settlement Code (BSC) Trading Arrangements
The BSC also defines the obligations on ELEXON, the Balancing and Settlement Code Company (BSCCo), in providing or procuring the services necessary to operate the trading arrangements efficiently and establishes the BSC Panel and defines its various responsibilities. A set of subsidiary documents including Balancing and Settlement Code Procedures (BSCPs), Communications Requirements and the Data File Catalogue are referenced by the BSC, and compliance with these is also a condition of the BSC. Other parties are recognised by the BSC.

The Transmission Company has many obligations under the BSC and is itself a Party to it. Also the roles of various Agents are described – these Agents are not Parties to the BSC but are appointed, either by ELEXON or by BSC Parties, to fulfil certain functions. Agents to the BSC include the Settlement Administration Agent (SAA), Central Data Collection Agent (CDCA) and the Funds Administration Agent (FAA), and these functions are performed under contract to ELEXON. Party Agents include the Energy Contract Volume Notification Agents (ECVNAs) that notify bilaterally contracted volumes on behalf of Parties, and Meter Operator Agents (MOAs). Other Party Agents, specific to those Parties that are Suppliers, are Half-Hourly and Non-Half-Hourly Data Collection and Data Aggregation Agents.

Together with Suppliers and MOAs, these go to make up the 'Supplier Hubs', an important element of the arrangements for the metering of domestic and commercial customers, whereby consumption in each half-hourly Settlement Period can be determined either using an half-hourly meter or using a 'demand profile' which apportions non half hourly metered consumptions to individual Settlement Periods. Finally, Distribution Companies are also bound by the BSC, essentially for the provision of certain metered data.

2.1.2.4 Changes to the Trading Arrangements

A significant aspect of the BSC trading arrangements is the ability for those arrangements to evolve as improvements are identified and as new requirements emerge. Accordingly, the BSC has mechanisms for the consideration, approval and incorporation of changes, known as Modification Proposals. Modification Proposals can be submitted by any BSC Party, energywatch and, in limited circumstances, the BSC Panel. The administration of the procedures for the consideration and development of these Proposals is one of the prime functions of the BSC Panel, which comprises: a Chairman (appointed by the Authority, via Ofgem); industry members (elected by Parties); a Transmission Company member (appointed by NGC); consumer members (appointed by energywatch); and independent members (appointed by the Chairman). The Modification Procedures culminate in a Modification Report to the Authority, via Ofgem, which contains the BSC Panel's recommendation as to whether or not a modification should be made. The final decision in each case rests with the Authority.

2.1.2.5 Further Information

Further explanation of the trading arrangements can be found in the following documents, all of which can be downloaded from the BSC (ELEXON) website – www.elexon.co.uk
• Balancing and Settlement Code
• Balancing and Settlement Code Summary
• Information Sheets
• ELEXON and BSC Panel Leaflets

2.2 Nord Pool – The common Power exchange of Norway, Sweden, Denmark and Finland

In order to create an efficient market a common market place with a number of actors and a substantial turnover is needed. This requirement constituted the basis for Nord Pool, which was founded in 1993 by the Norwegian Transmission system operator (TSO) Statnett and the Swedish TSO Svenska Kraftnät. In 1997 Finland and Denmark joined Nord Pool. Today more than 300 traders are active at Nord Pool, which means that Nord Pool is Europes most important power exchange at the moment.

The objectives o Nord Pool is power trading and power trading services. The Real time balancing is a business for the TSOs and Nord Pool is not involved. The main products today are:

- Spot - Hourly trading – Auction with Equillibirum price with Physical delivery next day
- Futures - Financial Contracts for Days, Weeks, Blocks, Seasons and Years up to 3 years ahead
- Clearing - Nord Pool Clearing is a Licensed Clearing House since 2002 that offers
    - Clearing of hourly trading
    - Clearing of financial contracts traded
        - At Nord Pool
        - In the bilateral market

The turnover has developed rapidly from 11 TWh in 1991 to 2800 TWh in 2001, in a common market with a physical turnover of around 400 TWh/year. The following table illustrates the development in volume and type of products.

Year	Turnover TWh	Spot TWh	Futures TWh	Clearing TWh
1993	11	10	1	0
1997	90	40	50	0
2001	2800	100	900	1800

Table 2.1 Development of the Nord Pool

2.2.1 Settlement system of Norway

The settlements system for a regional network owner is described in this section.

The network owner distributes power to non-hourly and -hourly metered customers. Some power will be lost as power flows through the network, due to resistance losses. The customers connected to the regional network pays for the cost of losses and other network costs through the network tariff. The power cost of the customers is charged according to a common residual profile not including network losses, under a separate power tariff.

The power flow into the regional grid is settled on hourly basis, as the spot price varies for each hour during the year. It is possible for a customer to buy power from the market by selecting a power supplier, even if the customer is not hourly metered. It is the network owner's responsibility to allocate or segment the power flow to the different power suppliers on hourly basis. The supplier/customer segmentation is performed in two stages:

Stage 1.
The network owner performs a preliminary segmentation of the total power flow into shares of different power suppliers daily. First, the net non-hourly metered power flow is found by subtracting hourly-metered load from the total flow.
Based on the assumption that the network loss is proportionate to the load (or more correct proportionate to the square of the load), and on the fractional seasonal share of network losses to total in-fed power, the network losses is estimated and subtracted. This yields the net power demand of the non-hourly metered customers called JIP (adJusted In-fed Profile), which is a residual power profile.
The hourly demand for each non-metered customer is then found based on the customer fraction of total seasonal power demand for the grid. The customer hourly load is found by multiplying the JIP value by the customer's seasonal fraction.
Each supplier's share of the load is then found by adding the served customers hourly load. It is important to note that stage 1 settlement is performed before the non-hourly metered customers meter is read.

Stage 2.
A final settlement on a customer basis is performed when a non-hourly metered customer's meter is read (the meters are read every 3. month). A correct seasonal demand is now available, and a revised customer fraction of total seasonal power demand is calculated. Based on the revised fraction new hourly values for the customers demand are calculated.

The network losses will be affected by the stage 2 settlement, as the network losses seasonal fraction can be altered when the customers demand changes.

2.2.2 Settlement system of Denmark

The main actors are:

- Nord Pool
- The system responsible Eltra (West Denmark) and Elkraft System (East Denmark)
- The balance providers
- The grid companies

The balance responsible has everyday to plan the supply for next day based on a forecast of the hourly demand. The input to Nord Pool on offers and bids forms the basis for creating the hourly pool prices for the next day. Offers on regulation possibilities for the next day creates a regulation price, which will be used for settlement of discrepancies between planned and real demand.

The opening of the Danish electricity market happened this way:

1/1 1998	customers > 100 GWh/y including 6 customers (few percent of the total)		
1/4 2000	> 10 GWh/y	211	16% of total consumption
1/1 2001	> 1 GWh/y	11.000	33%
1/1 2003	all customers	2 mio.	100%

By 171 2003, any domestic, commercial or industrial customer with consumption above 200.000 kWh is hourly metered. Customers below the boarder may also be hourly metered if they pay for the installation of hourly metering. By 1/1 2005, the boarder will be lowered to 100.000 kWh.

Customers with consumption above 200.000 kWh include around 20.000 customers using 48% of the total consumption. Customers with consumption above 100.000 kWh include around 35.000 customers using around 55% of the total consumption.

For customers without hourly metering, load profiling is used for settlement of their balance provider. The basis for this is the residual load profile of the local grid. Losses is the local grid are treated as profiled customers.

The load part from hourly-metered customers is calculated exactly for each balance provider and the balance settlement is finished for this part.

The settlement of profiled customers contains two steps:
1. Balance settlement of the profiled customers is performed by preliminary segmentation of the residual grid curve for each balance provider due to the last yearly consumption for customers summated per the balance provider.
2. After reading of all the profiled customers the settlement of the customers will take place and a final summation of consumption per month and balance provider will take place. The preliminary balance settlement of the balance providers will be adjusted according to the difference between the final and the preliminary delivery per balance provider. This is converted to a financial adjustment by multiplying with the weighted average pool prices from Nord Pool for the period considered.

2.2.3 Settlement system of Sweden

The main actors for the settlement are is Nord Pool (the Nordic Power exchange), the Swedish Transmission operator (Svenska Kraftnät), the balance providers and the grid operators.

The day before the delivery every balance responsible has to plan his supply for next day. This is done by forecasting the hourly demands for next day, planning his own production and bilateral purchases and sales and then finally by offers and bids to Nord Pool. This process also creates an hourly pool price that is used for resulting planned power exchange. Then some actors also offer special regulating possibilities for next day, which creates a regulation price, to be used for discrepancies between planned and real demands (both generation and consumption).

Electricity generation and supply is settled on hourly basis, as the spot price varies for each hour during the year. All customers with a maximum demand above 135 kW and all connected to high voltage lines have to be hourly metered. For customers without hourly metering a system for load profiling is used for settlement of their balance provider. The basis for this profiling is the load profile of the local grid.

This means that the settlement are divided on two major groups:
- Hourly settled customers
- Profiled customers

Losses in the local grids are treated as profiled customers, while losses in the national grid and in the transmission grids are hourly settled.

The settlement for the profiled customers contains two main steps:

- Preliminary settlement
- Final settlement

Settlement – step 1
The system responsible performs daily:

1. A calculation of the total daily load curve for each balance provider's deliveries to hourly metered customers
2. A preliminary segmentation of the total daily load curve in each local grid area into a daily load curve for each balance provider.

Then twice every month the preliminary financial settlement is finished. This settlement is divided on a final one for the hourly metered customers and preliminary one for the profiled customers. The basis for the financial settlement is the regulation prices.

Final settlement
After reading all profiled customers meters the final settlement of the profiled customers take place. While those customers are read only once a year the final settlement will take place around 14 months after the month of delivery.

The main steps in the final settlement are:

- Reading of customer meter
- Distribution of each customers consumption on monthly high load (HL) and low load (LL) periods
- Summing up of each balance provider's customers consumption on monthly HL and LL
- Calculation of losses in the local grid as the difference between electricity fed into the local grid and the total of all customers HL and LL consumption
- Comparison of each balance provider's preliminary settled delivery with the final sum
- Final financial settlement

The basis for the final financial settlement is a weighted average of the pool prices from Nord Pool.

2.2.4 Settlement system of Finland

The following gives a overview of the settlement system used in Finland:

In Finland the settlement system is hierarchical so that

- the distribution network owner is responsible for the settlement inside network area and reports results to balance responsible suppliers
- balance responsible suppliers are responsible for balance settlement with other balance responsible suppliers and report to the system operator Fingrid Systems
- Fingrid Systems is responsible for national balance and reports results back to balance responsible suppliers and network operators for checking
- balances are settled next day after the operating day (except weekends)
- at the distribution network level balances are settled only from such customers that have changed the supplier (rest is going to the balance of local supplier)
- hourly-metered values and load curve based values are handled identically in the balance settlement procedure

2.3 The French electricity market

Date	Eligible customers
February 1999	Annual electricity consumption > 100 GWh
May 2000	Annual electricity consumption > 16 GWh
February 2003	Annual electricity consumption > 7 GWh
July 2004	All customers except residential customers
2007	All customers

Table 2.2 Calendar for opening of the French Electricity Market

2.3.1 New entities

Energy Regulation Commission (CRE)

This is the independent administrative authority, set up in March 2000, the main task of which is to ensure fair and transparent network transmission and distribution. More generally it is entrusted with overseeing the smooth running of the market and to make sure there is no discrimination, cross subsidy or hindrance to competition. www.cre.fr

RTE
This is the French electricity transmission system operator, set up on July 1st 2000 in application of the law of February 10th 2000 on the modernisation and development of public service electricity. This law transposes European directive 96/92/CE of December 1996 into French law. RTE's main mission is to operate, maintain and develop the public transmission system in France. This means monitoring economic performance of its assets. www.rte.france.com

Powernext
This is France's first exchange launched on November 26th 2001.

Powernext is both an optional and anonymous organised exchange.

In terms of trading, Powernext offers standard hourly contracts with physical delivery the day after trading within the French hub.

Powernext maintains transaction liquidity by concentrating orders with auction procedure.

The physical delivery of the traded electricity is the responsibility of RTE. Powernext daily declares to RTE the volumes traded by its members.

Balancing responsible
This is a legal entity or natural person who is committed to RTE, through a Balance Responsible contract, to settling the costs of the imbalances observed a posteriori, on behalf of one or more network users attached to his scope. These imbalances result from the difference between the supplies and the consumption for which they are responsible.

2.3.2 Balancing Mechanism

The act of 10 February 2000 has effectively created the conditions for setting up by RTE of such a balancing mechanism in order to guarantee power system safety. It enables RTE to:

- mobilise reserves to ensure the generation-consumption balance in real time,
- contribute to solving network congestion,
- produce a legitimate reference price which can be used for the settlement of imbalances of Balance Responsible Entities.

Through a bidding system (offering either higher or lower prices), the players of the market communicate the technical and financial conditions on the basis of which RTE can modify their generation or consumption programmes. RTE makes up for any imbalances by selecting offers, after having ranked them according to a merit order criterion and by taking into account the technical constraints expressed by the partners.

RTE has set up the Balance Responsible service in order to facilitate the network access conditions, offer greater flexibility and improve the fluidity of the electricity market. This is a major contribution of the European internal market.

This service permits the players of the electricity market, who take on the capacity of Balance Responsible, to carry out their business transactions by minimising their exposure to costs for the settlement of the imbalances between their supplies on the one hand and their deliveries on the other hand.

A market player who becomes a Balance Responsible must commit himself to RTE to settle the imbalances for all of the consumption and injections that he takes charge of within his balancing scope.

On April 1st 2003, the Balance Responsible mechanism changed when the Balancing Mechanism got under way. To obtain the capacity of Balance Responsible, a market player must sign a Participation Agreement with RTE undertaking to respect the Rules relative to the Balance Responsible scheme, the Balancing Mechanism and the Programming.

For each half-hourly period during a given day, RTE subsequently calculates the Balance Responsible Entity’s Imbalance as being the difference between “Total Injection” and “Total Extraction”. Total Injection is calculated as being the sum of the whole injected energy including import transactions, purchase from Powernext and block Exchanges Programmes. Total Extraction includes Export Transactions, Loss Purchase Contracts and Block Exchange Programmes.

2.3.3 Load profiling for settlement

Until June 2004 only customers with an annual electricity consumption > 7 GWh are eligible. As all these customers are equipped with a remote reading interval meter. Their half-hourly power demand is known. From July 2004 all French commercial customers, are going to be eligible, including small customers without interval meters. Consequently a load profiling method to estimate these customers’ load curves, will be adopted by CRE and published before July 2004.

3 Temperature Response Comparison

This section examines the relationship between temperature and load before and after deregulation. The percentage change of total load has been calculated for a one degree Celsius change of the average temperature. To enable a meaningful comparison between countries the year has been divided into winter (Dec.-Feb.), spring (Mar.-May), summer (June-Aug.) and autumn (Sept.-Nov.) periods. Spring and autumn has been joined, as the results are similar.
The temperature sensitivity has been calculated for each season, for each day type, for each country. The day types are weekdays ("Work" – not corrected for holydays) and weekends (Saturdays and Sundays)
The last row and column in the table shows average values – and is included for better judgement of the values.

Values shown in italics have correlation coefficients less than 50% which indicates low significance of the temperature sensitivity. Low significance generally is connected to low sensitivity since other factors that influence on the consumption are relatively constant during the year. Temperature sensitivities that have low significance should be used with caution.See also table 3.2 showing the corresponding correlation coefficients.

COUNTRY	DEREGULA-TION. STATUS	WINTER		SPRING AND AUTUMN		SUMMER ****		
		Work	Wend	Work	Wend	Work	Wend	Average
Norway	Before	-1.47	-1.32	-2.42	-2.19	-1.45	-1.24	-1.68
	After	-0.97	-1.43	-2.63	-2.53	-0.80	-0.80	-1.53
Sweden	Before	-1.63	-1.79	-2.23	-2.34	*0.04*	*-0.25*	-1.37
	After	-1.14	-1.48	-2.25	-2.11	*-0.86*	-0.89	-1.46
UK	Before	-1.45	-1.10	-1.99	-1.71	*-0.16*	*-0.24*	-1.11
	After	*-0.08*	-0.66	-1.84	-1.59	*0.16*	*0.01*	-0.67
France ***	Before	-1.28	-2.11	-2.43	-2.46	*-0.13*	*-0.16*	-1.43
	After ***	-2.00	-2.54	-1.87	-2.00	*-0.04*	*0.20*	-1.38
Finland *	Before *							
	After	*-0.37*	-0.73	-1.18	-1.17	*-0.47*	*-1.32*	-0.87
Denmark **	Before	-1.45	-1.40	-1.52	-1.55	*-0.25*	*0.03*	-1.02
	After **	*-0.17*	-0.78	-0.95	-0.94	*-0.02*	*-0.12*	-0.50
Average		-1.00	-1.28	-1.78	-1.72	*-0.33*	*-0.40*	-1.08

Table 3.1 Temperature sensitivities before and after deregulation.

*) Missing values before deregulation in Finland
**) In 2001 only 33% of the Danish consumption was included in the free market
***) Development of the free market not yet matured
****) In general low correlation factors for summer, this indicates low significance of temperature sensitivities during summer.

As the table shows, no radical change has happened since deregulation of the markets in the investigated countries. Generally, Finland, Denmark and UK have the lowest temperature sensitivities; Norway, Sweden and France have the highest (negative) values. Sweden is the only country that has higher sensitivities after deregulation compared to before.

All Norwegian and Swedish values are more negative than the average. The deregulation of Norway seems to have lead to higher temperature sensitivity for all other columns, except summer and winter workdays. This can be explained by a growth of demand of the domestic sector.

Sweden seems to have another development – less temperature sensitivity in the cold seasons since deregulation, and higher (negative) values during summer. No clear explanation is found to account for this.

UK has a dramatic reduction of sensitivity of the winter season since deregulation, no clear explanation is found.

Regarding France, in 2001 the customers sensitive to weather conditions were not yet eligible to the market. In 2001, France has the highest temperature sensitivity in winter season. This can be explained by the fact that el. prices are relative low in France and by the development of electricity space heating since 1973 in response to the oil crisis. However EDF on the one hand has promoted a better insulation and the use of energy controllers and on the other hand has launched real-time tariff options (EJP, Tempo). These new options have disturbed the correlation between daily electricity consumption and temperature. Concerning summer the results are not significant and nothing can be concluded except that the influence of air conditioning is not yet visible.

For Finland we miss temperature data for a year before deregulation, so no sensitivity has been calculated for this reason. The sensitivities after deregulation are quite low, even though Finland is a cold country. This indicates use of non-electric space heating.

In 2001, Denmark has reduced values compared to year 1998 (before deregulation). This might be explained by other reasons than deregulation since only 33% of the Danish consumption participated in the free market in 2001. One of the reasons might be that the authorities of Denmark during the later years has taken measures reduce the use of electric space heating by changing to district heating or distributed natural gas.

Correlation factors of the sensitivity calculations are shown in Table 3.2. Correlation factors less than 50% are shown in *italics*, indicating low significance of the corresponding temperature sensitivity.

CORRELATION		WINTER		SPRING AND AUTUMN		SUMMER		
		Work	Wend	Work	Wend	Work	Wend	Average
Norway	Before	-0.72	-0.80	-0.91	-0.90	-0.77	-0.84	-0.83
	After	-0.71	-0.90	-0.93	-0.94	-0.53	-0.73	-0.79
Sweden	Before	-0.73	-0.84	-0.90	-0.95	*0.02*	*-0.16*	-0.59
	After	-0.78	-0.97	-0.91	-0.95	*-0.41*	-0.66	-0.78
UK	Before	-0.57	-0.50	-0.75	-0.73	*-0.14*	*-0.23*	-0.49
	After	*-0.03*	-0.52	-0.71	-0.77	*0.16*	*0.01*	-0.31
France	Before	-0.54	-0.86	-0.84	-0.88	*-0.05*	*-0.10*	-0.54
	After	-0.76	-0.83	-0.77	-0.85	*-0.02*	*0.14*	-0.52
Finland	Before							
	After	*-0.30*	-0.81	-0.91	-0.90	*-0.19*	*-0.37*	-0.58
Denmark	Before	-0.57	-0.78	-0.62	-0.86	*-0.06*	*0.01*	-0.48
	After	*-0.06*	-0.71	-0.61	-0.74	*-0.01*	*-0.10*	-0.37
Average		-0.48	-0.71	-0.74	-0.79	*-0.17*	*-0.25*	-0.52

Table 3.2 Correlation factors of temperature sensitivities before and after deregulation

4 Present tariff structures

4.1 UK

The introduction of the New Electricity Trading Arrangements (NETA) in England and Wales on 27 March 2001 abolished the common Pool Selling Price (spot price). Wholesale prices are now subject to confidential bilateral contracts between electricity generators and suppliers.

	TWh	No. of Customers '000	kWh per customer
Domestic	**111.842**	**26,281**	**4,256**
Standard	73.652	20,491	3,594
Economy 7 and other off-peak	37.887	5,726	6,617
Sales under other arrangement	0.303	64	4,734
Non-Domestic	**217.077**	**2,064**	**105,173**
Non-MD Unrestricted	21.978	1436	15,305
Non-MD E7 and other off-peak	10.155	407	24,951
MD Metering 0-20% Load Factor	3.281	43	76,293
MD Metering 20-30% Load Factor	5.907	54	109,388
MD Metering 30-40% Load Factor	4.651	32	145,334
MD Metering >40% Load Factor	4.094	21	194,949
Half-Hourly Metered Customers	165.026	71	2,324,307
Public lighting	1.986		
TOTAL FINAL CONSUMPTION	**328.919**		

Table 4.1 Tariff structure of UK

Definitions:

Domestic Standard	A tariff with a single price for all kWh units consumed and where the premises are wholly or mainly for residential purposes. There is usually, in addition, a standing charge.
Domestic Economy 7	A tariff with two prices, a 'normal' rate applicable for 17 hours of each day and a 'low' rate applicable for 7 hours. The low rate period may be split into 2 separate periods. Again, there is usually, in addition, a standing charge. Special metering is required. The dual rate periods may be fixed or varied by radio teleswitch.
Domestic other off-peak	Any other domestic tariff with 2 or more separate prices according to when electricity is consumed.
Non-Domestic Non-MD Unrestricted	Tariffs with no time of day metering and no maximum demand (MD) metering but where there may be a higher price for a primary block of units consumed and lower follow-on rates for additional consumption in a period.
Non-Domestic Non-MD E7 and other off-peak	Tariffs with no maximum demand metering and otherwise similar to the definitions for domestic Economy 7 and other off-peak tariffs.
Non-Domestic MD Metering 0-20% Load Factor	Any tariff where there is £/kW or £/kVA demand charge(s) applicable to the maximum metered demand irrespective of whether there is time of day metering and pricing and where the load factor (ratio of average hourly consumption (kWh) in a period to the maximum demand (kW)) is in the range 0-20%.
Non-Domestic MD Metering 20-30% Load Factor	Any tariff where there is £/kW or £/kVA demand charge(s) applicable to the maximum metered demand irrespective of whether there is time of day metering and pricing and where the load factor (ratio of average hourly consumption (kWh) in a period to the maximum demand (kW)) is in the range 20-30%.
Non-Domestic MD Metering 30-40% Load Factor	Any tariff where there is £/kW or £/kVA demand charge(s) applicable to the maximum metered demand irrespective of whether there is time of day metering and pricing and where the load factor (ratio of average hourly consumption (kWh) in a period to the maximum demand (kW)) is in the range 30-40%.
Non-Domestic MD Metering >40% Load Factor	Any tariff where there is £/kW or £/kVA demand charge(s) applicable to the maximum metered demand irrespective of whether there is time of day metering and pricing and where the load factor (ratio of average hourly consumption (kWh) in a period to the maximum demand (kW)) is over 40%.

[UK]	Number of Customers (,000)	Percentage of Customers	Annual Consumption (TWh)	Percentage of total annual consumption
Spot Price	0	0.0	0.00	0.0
Maximum Demand	150	0.5	17.93	5.5
Time of Day	6133	21.6	48.04	14.6
Dynamic	0	0.0	0.00	0.0
Unrestricted	21927	77.4	95.63	29.1
Interval Metered	71	0.3	165.03	50.2
Other	64	0.2	2.29	0.7

Table 4.2 Tariff structure after deregulation in UK

4.2 Denmark

[DK]	Number of Customers	Percentage of Customers	Annual Consumption (TWh)	Percentage of total annual consumption
Spot Price	~ 30	Not available	Not available	Not available
Maximum Demand				
Time of Day	20 000 *	0.7 %	17 TWh	48%
Dynamic				
Unrestricted **	2 800 000	99%	18 TWH	52%
Interval Metered	20 000 1/1 2005 it will be 35 000	0,7% 1/1 2005 it will be 1.2 %	17 TWh 1/1 2005 it will be 19-20 TWh	48% 1/1 2005 it will be 55%
Other				

Table 4.3 Tariff structure after deregulation in Denmark

Note on tariff descriptions:

*) All Danish customers are forced to buy “prioritised consumption” (electricity produced by wind mills and localised CHP plants). The customers with yearly consumption above 200000 kWh pay due to a time of day tariff for their “prioritised consumption” which is around 45% of their total consumption. The border will be 100000 kWh from 1/1 2005 including 35000 customers.

**) Unrestricted – same price per kWh all day every day

4.3 Finland

Network tariffs and public sales tariffs are separated, but the structure is usually the same

The main types of tariffs in Finland are:

1. Single rate tariff with no maximum demand charge. This is the standard tariff for domestic customers (usually < 10000 kWh/year). It usually includes fixed charge related to the size of the main fuse (standard for domestic customers 3 x 25 A, in some older flats 1x 25 A)

2. Several types of time-of use tariffs mainly for households with electric heating or other customers without peak-load (kW) charge. It usually includes fixed charge related to the size of main fuse. Number of time zones (registers in the meter) is usually 2 – 4 having
   - high rate during working days (sometimes also Saturdays/Sundays) usually 13 – 15 hours/day), low rate during other hours
   - seasonal tariffs having highest seasonal rate as above during working days, but only usually between 1st of November to the end of March. During low seasons there may also be two rates.

3. Similar time of use tariffs as above for larger industrial and other customers with peak-load demand charge. Peak demand is typically measured as an average of the two highest 15 minute peaks.

4. For larger customers there are often also reactive power tariffs (applied usually, if the share of reactive power is higher than 25 % of active power)

4.4 France

[France]	Number of Customers (,000)	Percentage of Customers	Annual Consumption (TWh)	Percentage of total annual consumption
Spot Price				
Maximum Demand	0			
Time of Day (Off-peak)	10400	34.0		
Dynamic (EJP + Tempo)	1270	4.2		
Unrestricted (Basic)	18900	61.8		
Interval Metered	0	0		
Other	0	0		
			160	

Table 4.4 Tariff structure before deregulation in France in the residential and professional sectors.

Name/type of Tariff	Number of customers
BLUE TARIFF (BASIC)	18,9 million
BLUE TARIFF (OFF PEAK)	10,4 million
EJP	0,83 million
tempo	0,44 million

Table 4.5 Distribution of EDF customers according to tariffs in 2001
(residential and professional sector with power demand <= 36kVA))

- Basic means the same price all day long and all year long.

- Off peak means: every day 2 periods: 8 hours (not necessarily consecutive) less expansive during the night or in the middle of the day. For each customer these hours are the same all year long. Though the cheaper period does not occur at the same time for all customers, everyone takes advantage of cheaper price everyday for 8 hours.

- EJP means: 6 hours (during the night 1 a.m. to 7 a.m.) for 22 days (from December 1rst to March 31st) declared the day before, much more expensive. This tariff, no longer proposed, is little by little replaced by *tempo*

- *Tempo* includes:

    - 3 types of days (300 blue days, 63 white days, 22 red days)
    - 2 periods within each type of day (night and day) with electricity price less expansive in the night.

    The electricity price varies as follows:

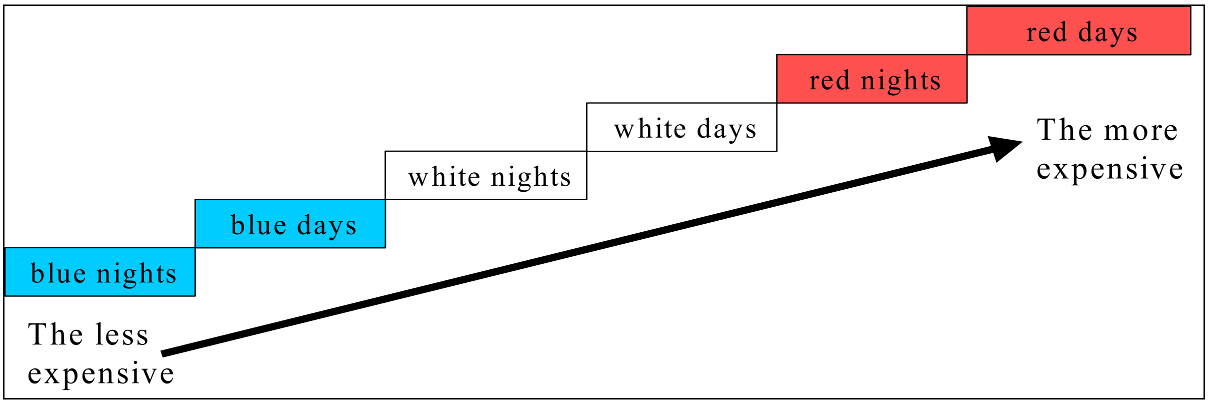

Figure 4.1 The "Tempo" tariff of France

4.5 Sweden

[Sweden]	Number of Customers (,000)	Percentage of Customers	Annual Consumption (TWh)	Percentage of total annual consumption
Spot Price	Commercial secrets			
Maximum Demand	Used only for network tariffs			
Time of Day	Commercial secrets			
Dynamic	Commercial secrets			
Unrestricted	Commercial secrets			
Interval Metered	All above 135 kW	2%	85	55%
Other	All below 135 kW Roughly 5 millions	98%	65	45%

Table 4.6 Tariff structure after deregulation in Sweden

Time of Use (ToU) tariffs were introduced in the early 1980:ies mainly for customers with an annual consumption above 10 MWh. Before the deregulation more than 10% of the customers used ToU tariffs. While most customers want to know the price they prefer a single rate tariff. Therefore, after the deregulation the number of customers with ToU tariffs have been falling rapidly. Instead most customers have a single rate tariff and those who are prepared to take risks have got Spot price connected contracts.

4.6 Norway

Norway Network tariff	Number of Customers [1000]	Percentage of Customers	Annual Consumption [TWh]	Percentage of total annual consumption
Spot price hourly metered cust.				
Spot price profile cust				
Maximum Demand	150	7 %	66	59 %
Unrestricted	2000	91 %	39	34.67 %
Firm price				
Interruptible load	50	2 %	7.5	6.67 %
Total	2200	100.00 %	112.5	100 %

Norway Energy price tariff	Number of Customers (,000)	Percentage of Customers	Annual Consumption (TWh)	Percentage of total annual consumption
Spot price hourly metered cust.	30	1 %	73.5	65.33 %
Spot price profile cust	200	9 %		
Maximum Demand	100	5 %		
Unrestricted	1570	71 %	39	34.67 %
Firm price	300	14 %		
Total	2200	100 %	112.5	100 %

Table 4.7 Tariff structure after deregulation in Norway 2001 (approximation from several sources)

5 *Comparison of load before and after deregulation*

The peak loads shown in this chapter are based on metered total system load for each country, before and after deregulation. For some countries it has not been possible to achieve metered values from before deregulation, so data for a later year is used in such cases.

5.1 *Peak load UK*

A comparison of the peak load days for UK for 1997 and 2001 shows very little change as shown in the next Figure. The peak hour of 2001 shows a higher value than 1997, an increase of 4.3%. The hour of max also comes later in 2001 (18 hours) than in 1997 (17 hours).

Year	Max date	Max hour	Peak value MWh/h	Temperature Centigrades
2001	17/12/2001	18	52079	4.5
1997	17/12/1997	17	49921	2.3

Table 5.1 Comparison of peak days for UK

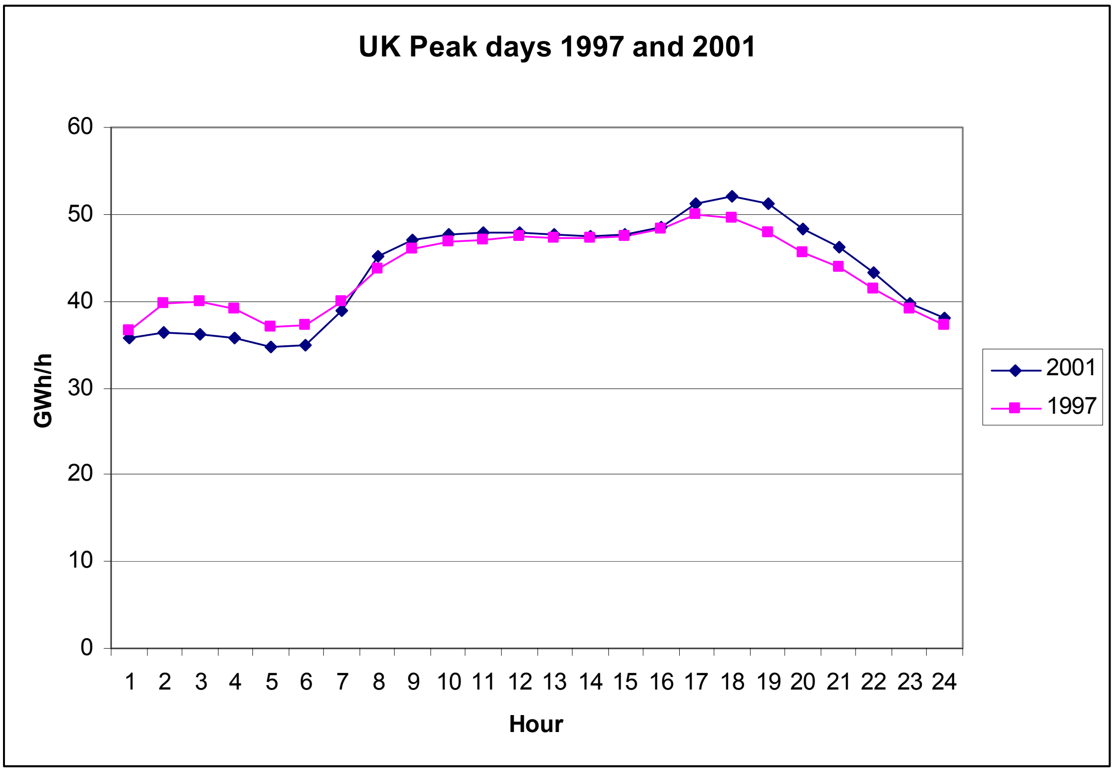

Figure 5.1 Comparison of peak day for UK before and after deregulation

5.2 Peak load Norway

A comparison of the peak load days for Norway for 1991 and 2001 shows a great change as shown in the next Figure. The peak hour of 2001 shows a higher value than 1991, an increase of 23.2%. The hour of max comes earlier in 2001 (10) than in 1991 (11). It is clear to see that the overall shape of the profile is quite similar in both years, although there seems to be greater demand during morning in 2001 than in 1991. The profile of 2001 also shows a second peak period in the evening, whereas the profile of 1991 shows a gradually decrease of demand during evening.

Year	Max date	Max hour	Peak value MWh/h	Temperature Centigrades
2001	05/02/2001	10	23054	-22
1991	08/02/1991	11	18700	-10.7

Table 5.2 Comparison of peak days for Norway

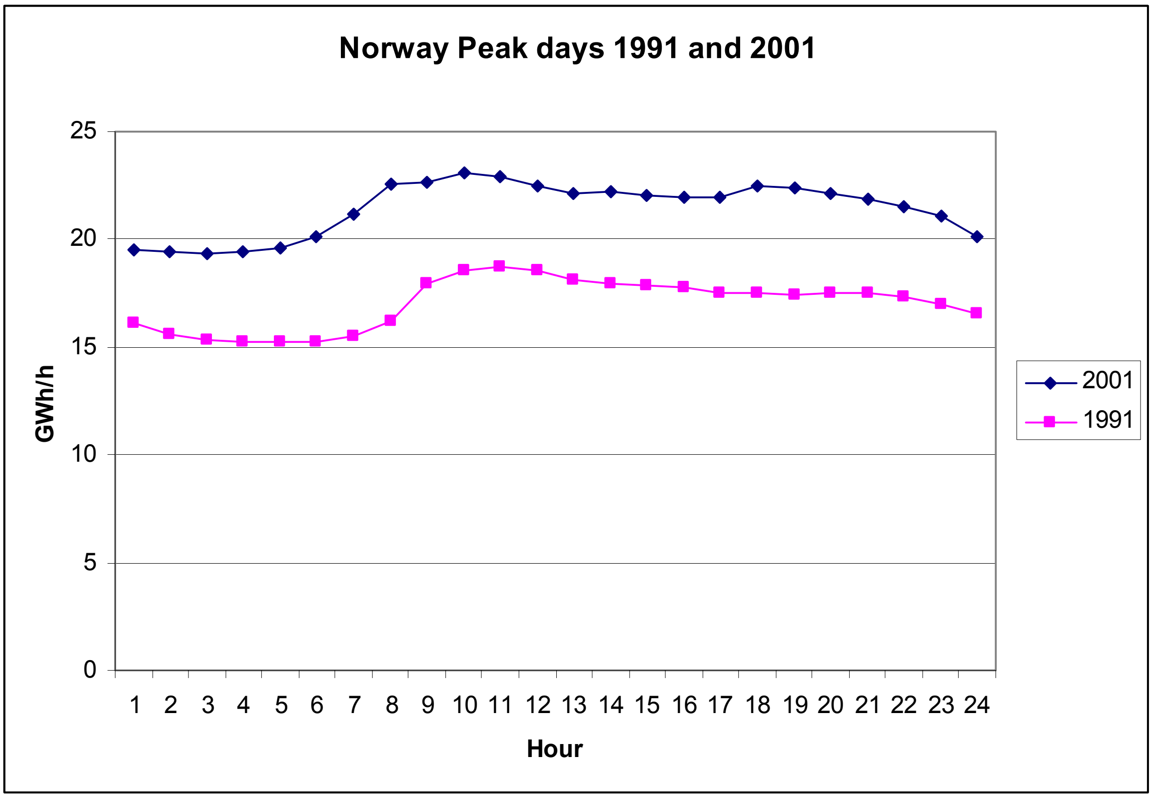

Figure 5.2 Norway, peak day profiles before and after deregulation

5.3 Peak load Denmark

A comparison of the peak load days for Denmark for 1998 and 2001 shows only minor change as shown in the next Figure. The peak hour of 2001 shows a slightly *lower* value than 1998, a decrease of 2.09%. The hour of max comes at 18 o'clock in both years.

Year	Max date	Max hour	Peak value MWh/h	Temperature Centigrades
2001	05/02/2001	18	6223	-5.0
1998	09/12/1998	18	6353	-7.9

Table 5.3 Peak days of Denmark 1998 and 2001

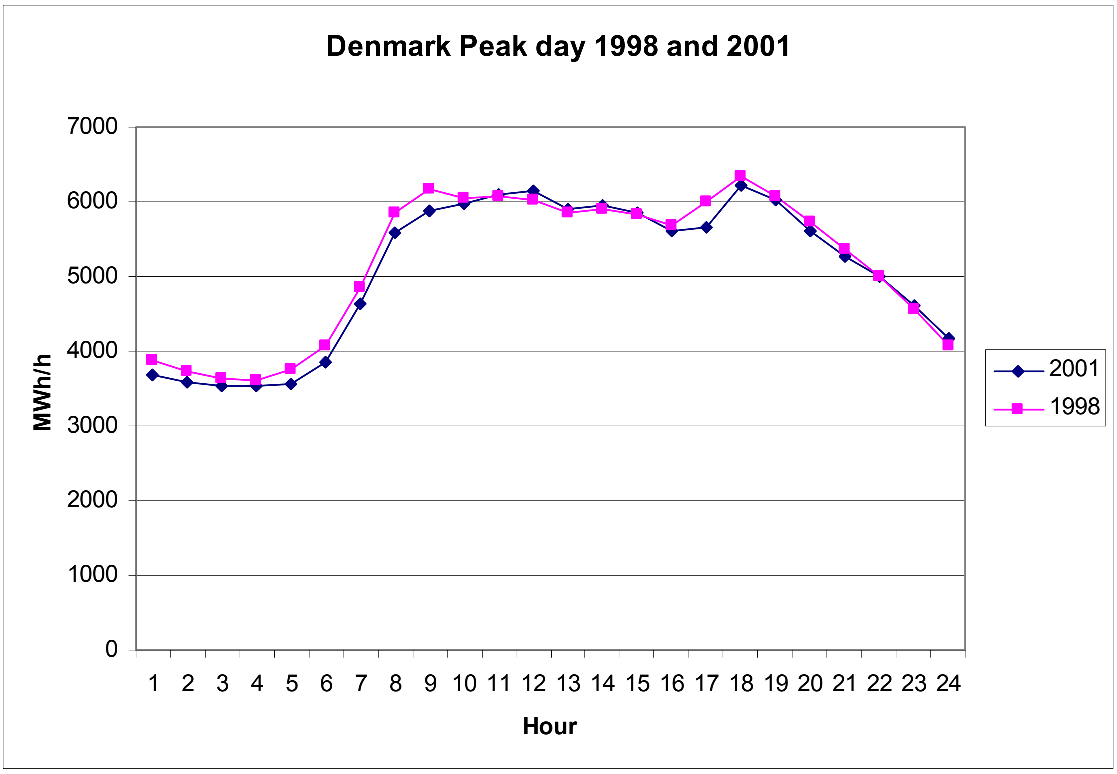

Figure 5.3 Denmark, peak day profiles before and after deregulation (33% of electricity sales are from open market)

5.4 Peak load Sweden

A comparison of the peak load days for Sweden of 1996 and 2001 shows only minor change as shown in the next Figure. The peak hour of 2001 shows a slightly higher value than 1996, an increase of 2.64%. The hour of max comes at 18 o'clock in 2001 and 9 hours in 1996. The late hour of the peak in 2001 is due to media influence. Media informed of a possible difficult situation in the electricity distribution of Sweden prior to the peak day, which resulted in a reduction in load during the work hours, giving a "pay back" load - and a peak at later hours than normal.

Year	Max date	Max hour	Peak value MWh/h	Temperature Centigrade
2001	05/02/2001	18	26323	-9.6
1996	07/02/1996	9	25646	-14.4

Table 5.4 Peak days of Sweden 1996 and 2001

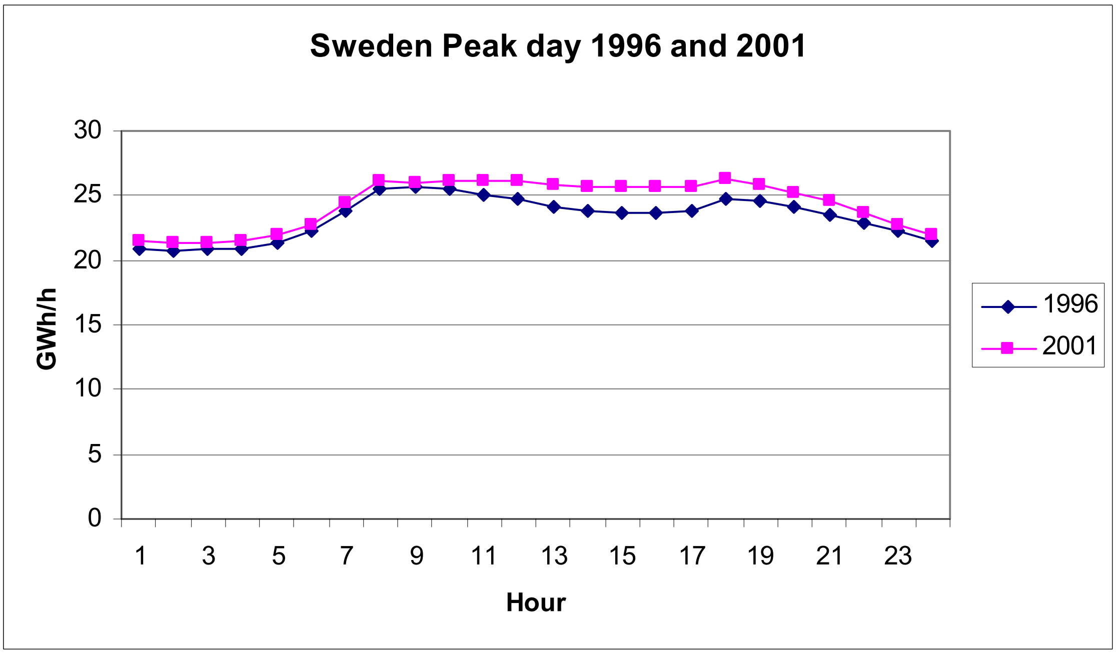

Figure 5.4 Sweden, peak day profiles before and after deregulation

5.5 *Peak load France*

A comparison of the peak load days of France for 1996 and 2001 shows relative great change for all hours as shown in the next Figure. The peak hour of 2001 shows a quite higher value than 1996, an increase of 10.5%. The hour of max comes in the evening in both years, on hour earlier for the late year 2001 (19 o'clock).

Year	Max date	Max hour	Peak value MWh/h	Temperature Centigrade
2001	17/12/2001	19	76298	-0.3
1996	20/02/1996	20	68266	-1.2

Table 5.5 France peak days of 1996 and 2001

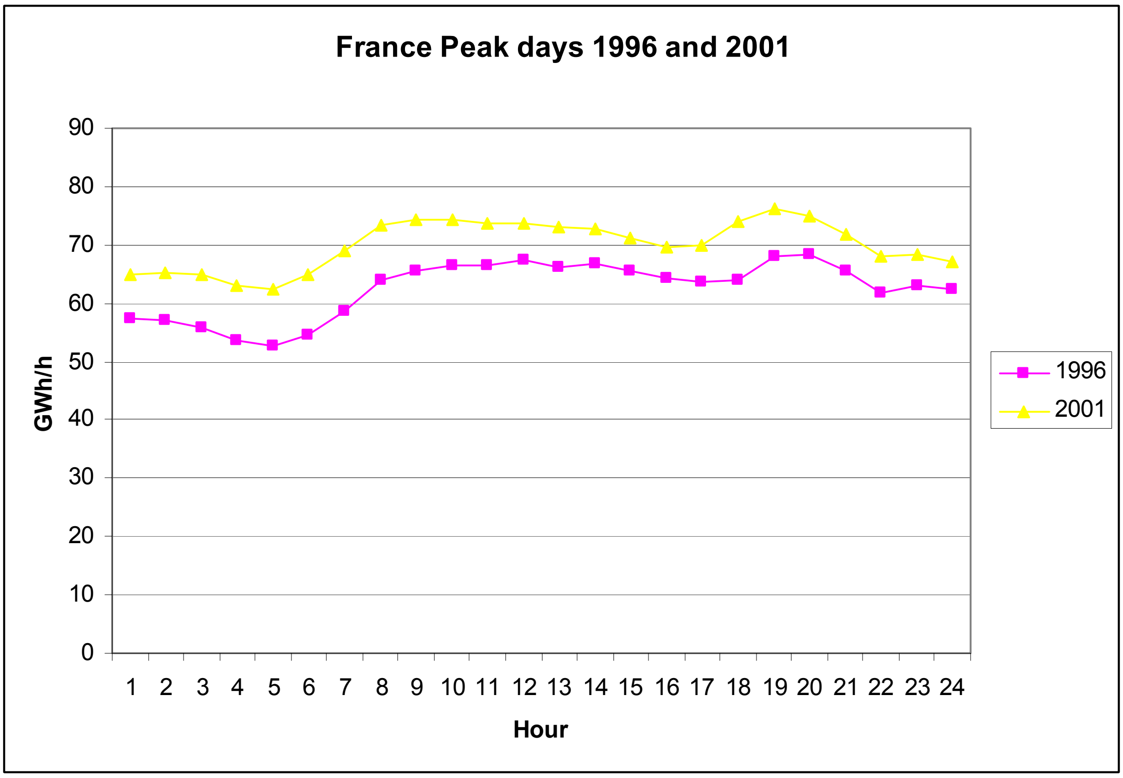

Figure 5.5 France, peak day profiles before and after deregulation

5.6 *Peak load Finland*

A comparison of the peak load days of Finland of 1995 and 2001 shows relative great change for all hours as shown in the next Figure. The peak hour of 2001 shows a much higher value than 1995, an increase of 21.3%. The hour of max comes in the same hour interval in both years (8-9 hour interval), but the demand is quite flat (unchanged) during work hours for both days.

Year	Max date	Max hour	Peak value MW	Temperature
2001	05/02/2001	9	13310	-21.1
1995	19/12/1995	9	10974	-15.3

Table 5.6 Finland peak days of 1995 and 2001

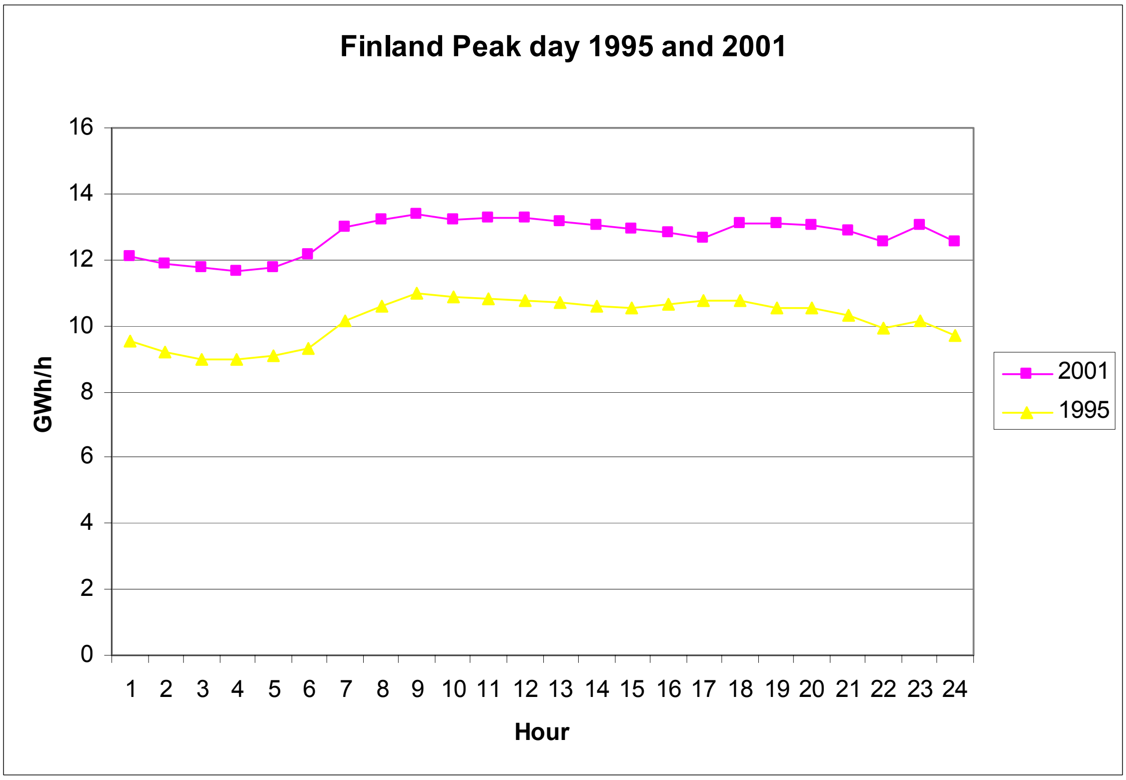

Figure 5.6 Finland, peak day profiles before and after deregulation

6 *Norway- load changes since deregulation*

Changes of power demand at peak day since deregulation
Results from simulations based on annual energy demand from 1991 and 2001, indicates that since 1991 (before deregulation) the share of power demand of process industry has shrunk from 29.5% to 24.7% (-4.8%), and the share from the public service sector has grown from 22.9% to 26.2% (+3.3%). Data also indicates that the share from Non-prioritised load has been reduced with 0.5 % in the period, and that the share from residential customers has grown with 0.8%.

Statistics show that the load from el. boilers of 2001 should be half of what is shown in the figures, This is due to the effect of high pricing during the peak days of this year, leading to use of oil backup at many customers. The customer model used in this report does not take the effect of pricing into account, so the demand of el. boilers (non prioritised load) therefore is over estimated.

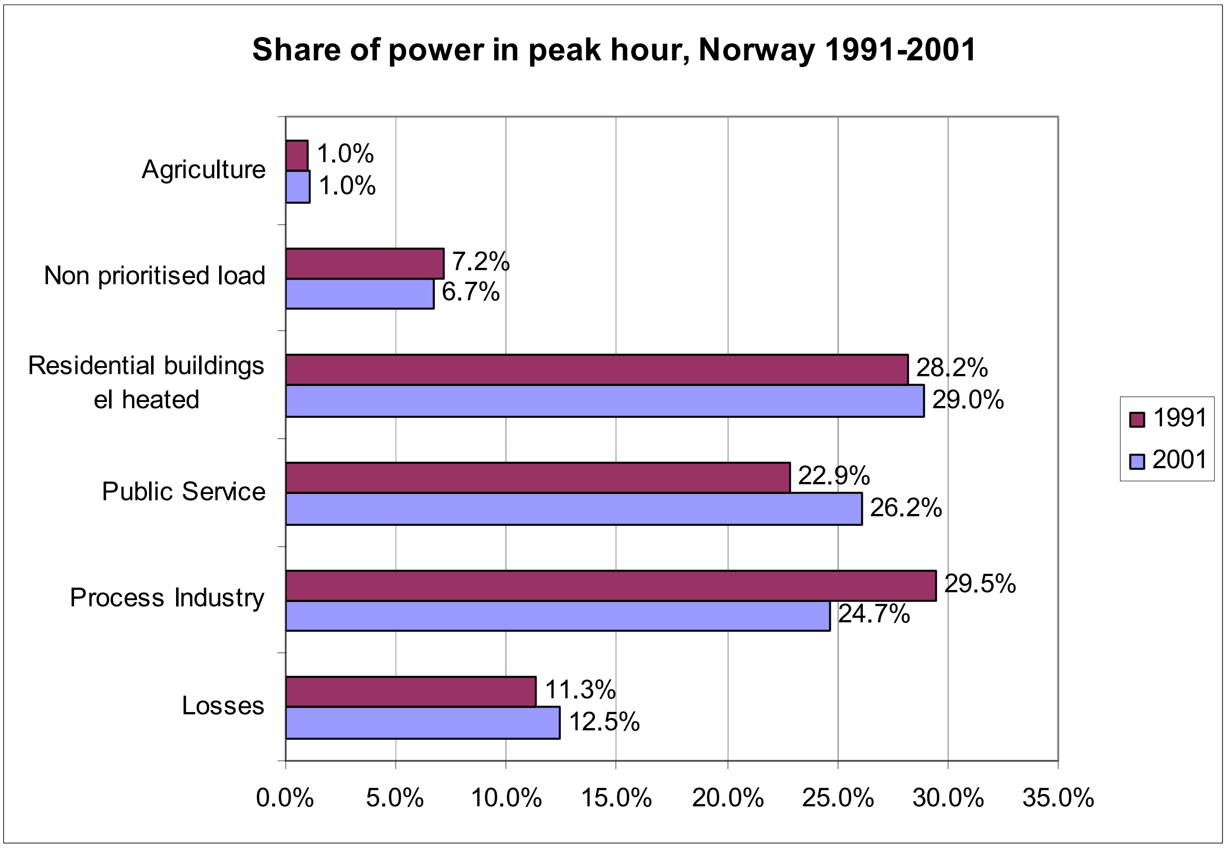

Figure 6.1 Share of power at peak hour in Norway a comparison of data from 1991 and 2001.

6.1 Peak day curves for Norway

The Figures shows peak day customer segmentations for Norway, for 2001 (after) and 1991 (before deregulation). To enable comparison, both simulations are performed based on the climate of 2001. The lower power demand of 1991 must be caused by different number and behaviour of the customers, and could also be a side effect of deregulation. The overall difference is a growth in demand from public service and residential customers. The industry sector shows only minor changes in the demand since 1991.

The peak has grown from 18.7 GW to 23.05 GW up with ca 23%. The growth has been in all sectors except the industry sector.

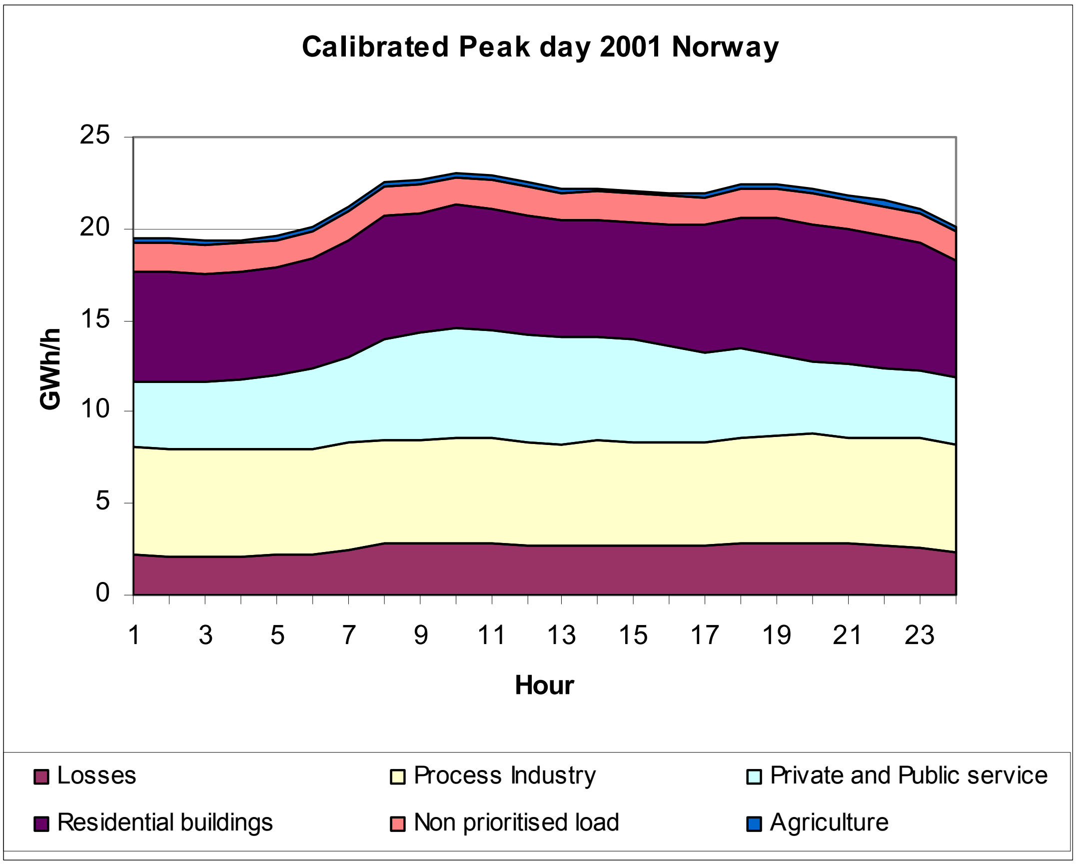

Figure 6.2 Peak day of 2001, 5/2-2001 at 10 o'clock 23.05 GWh/h.
Temperature: –22 Centigrade in Oslo

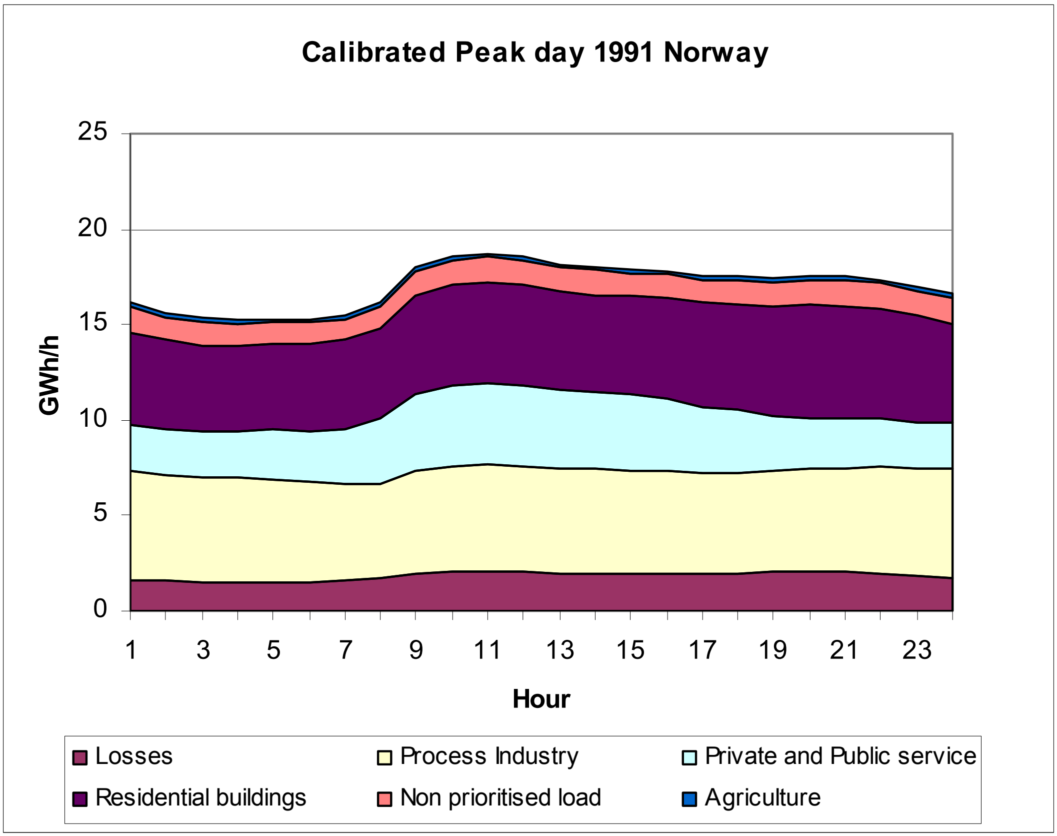

Figure 6.3 Peak day of 1991, 8/2-2001 at 11 o'clock 18.7 GWh/h.
Temperature: –10.7 Centigrade in Oslo.

6.2 Share of annual energy demand

Statistics from SSB [1] indicates that since 1995 (before deregulation) the share of energy demand of process industry has shrunk from 38.8% to 36.8% (-2.0%), and the share from the public service sector has grown from 15.4% to 17.5% (+2.1%). Data also indicates that the share from Non prioritised load has been reduced with 0.3 % in the period, and that the share from residential customers has been unchanged.

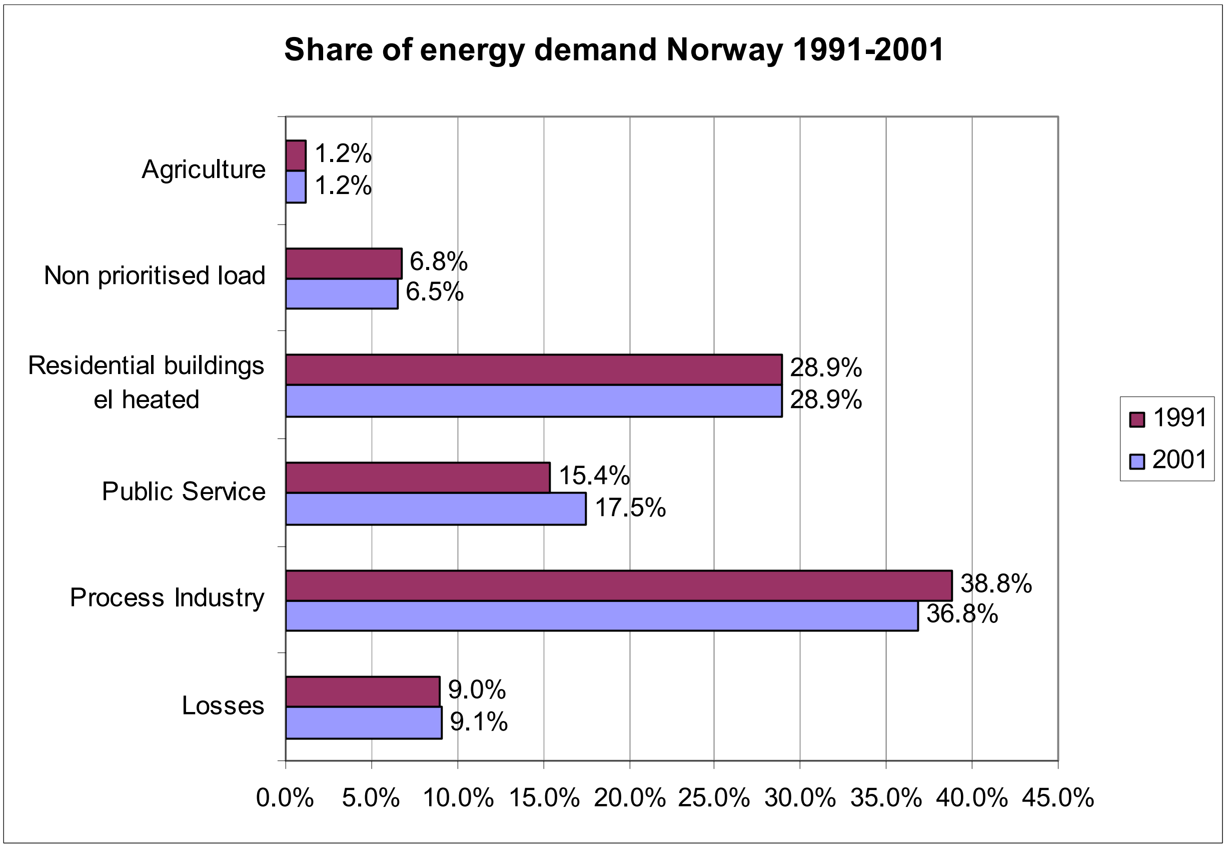

Figure 6.4 Share of annual energy demand in Norway, a comparison of data from 1991 and 2001.

6.2.1 Annual energy demand segmented into customer types

The Figures shows annual customer segmentations for Norway, for 2001 (after) and 1991 (before deregulation). The lower energy demand of 1991 must be caused by different number and behaviour of the customers, and can be a side effect of deregulation. The overall difference is a growth in demand from public service and residential customers. The industry sector shows only minor changes in the demand since 1991.

The total annual energy demand has risen from 110.4 TWh to 123.3 TWh, an increase of 11.7 %.

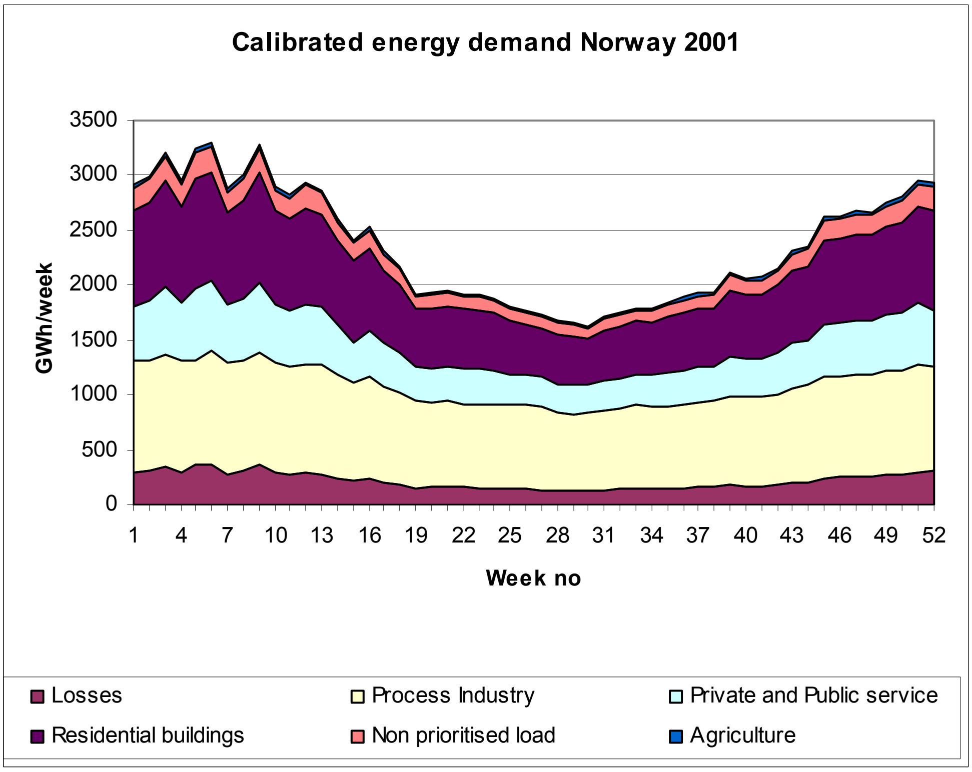

Figure 6.5 Customer segmentation of 2001 for Norway

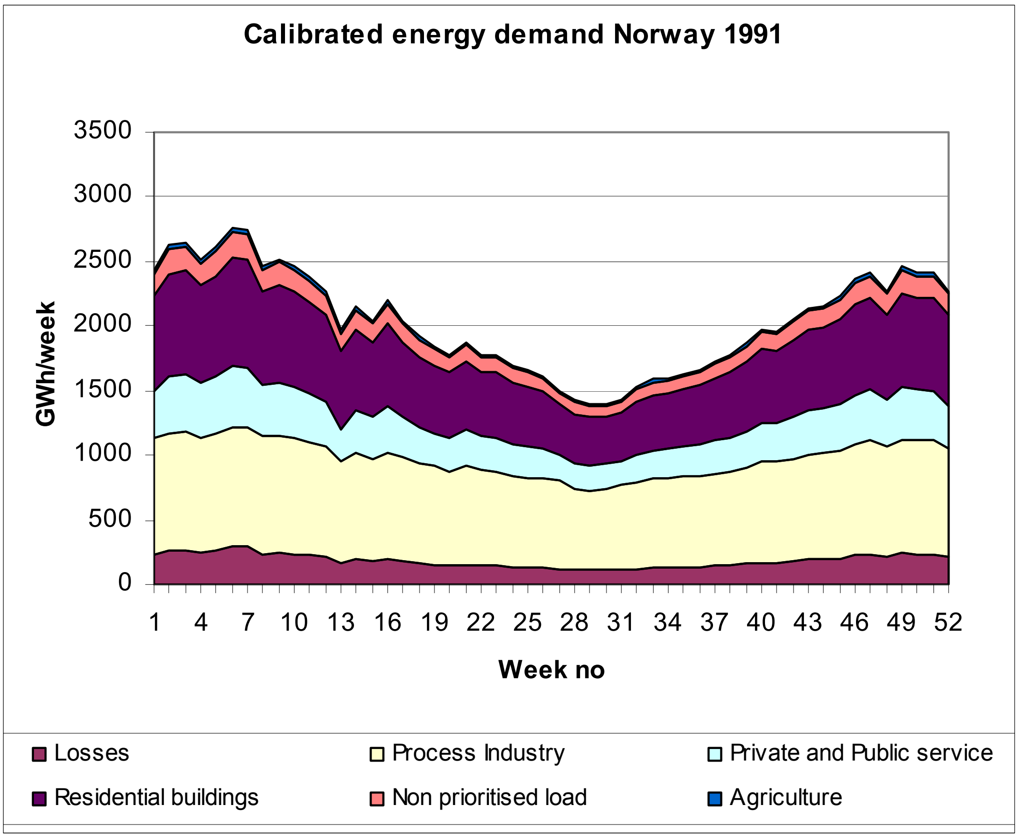

Figure 6.6 Customer segmentation of 1991 for Norway

7 Finland- load changes since deregulation

7.1 Changes of power demand at peak day since deregulation

Results from simulations based on annual energy demand from 1995 and 2001 indicates that since 1995 (before deregulation) the share of power demand of process industry has grown from 24.9% to 27.7% (2.8%), and the share from the public service sector has grown from 8.8% to 9.8% (+1.0%). Data also indicates that the share from the domestic sector has been reduced from 24.9% to 19.9% in 2001, a decrease of 5 % in the period.

The simulations of Finland are not temperature corrected, so part of the difference of load can be the result of change in low temperature between the two simulation years.

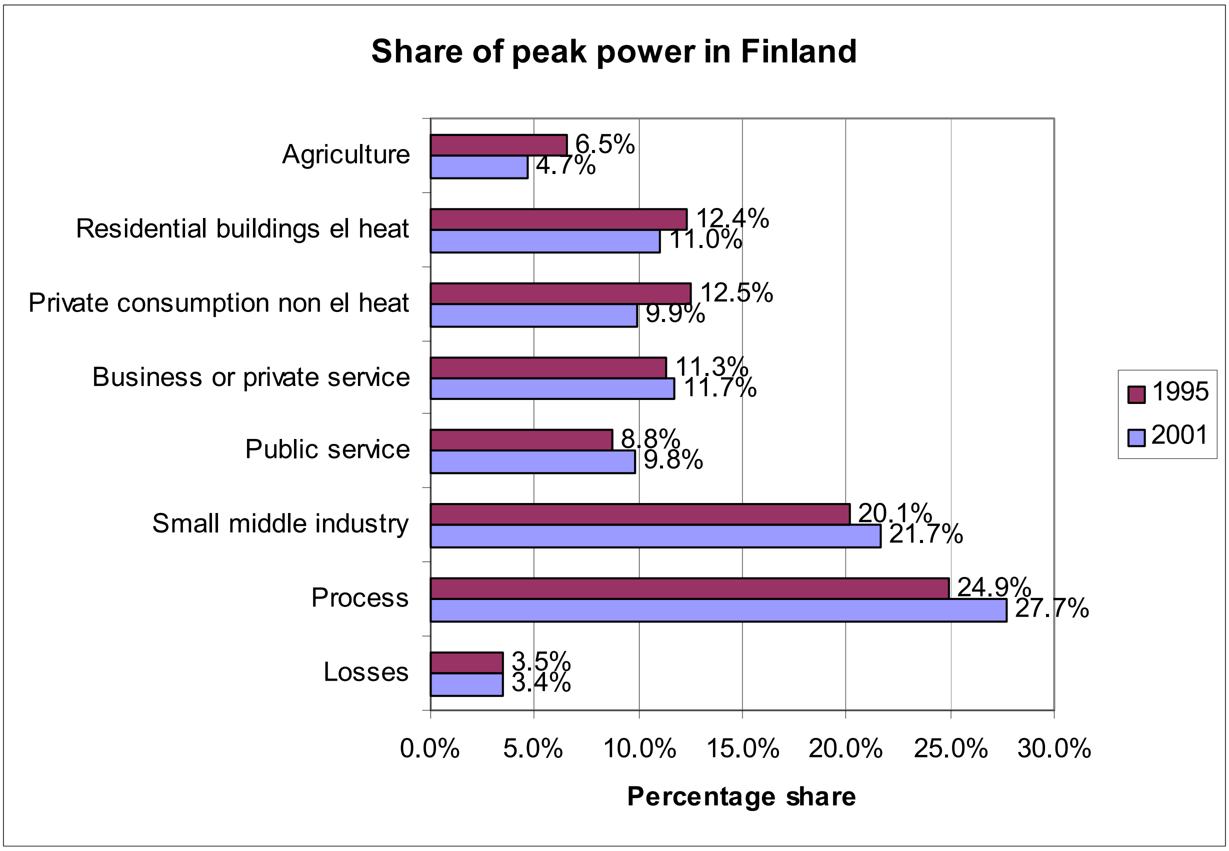

Figure 7.1 Share of power at peak hour in Finland, a comparison of data from 1995 and 2001

7.2 Peak day curves for Finland

The Figures shows peak day customer segmentations for Finland, for 2001 (after) and 1995 (before deregulation). The difference in peak load is partly a result of different temperature of the peak days: In 1995 the temperature was –15.3, and in2001 the temperature was –21.1. The overall difference is a growth in demand from public service and residential customers. The industry sector shows only minor changes in the demand since 1995.

The peak has grown from 10.97 GW in 1995 to 13.4 GW in 2001 up with ca 22%. There has been growth in all sectors, but mainly in the industry sector.

Special for Finland seems to be the domestic sector where the demand is higher during night than during daytime. This can be the result of accumulation of (space) heating during night, for use during daytime, and may be the result of using TOU tariffs with lower prices during night.

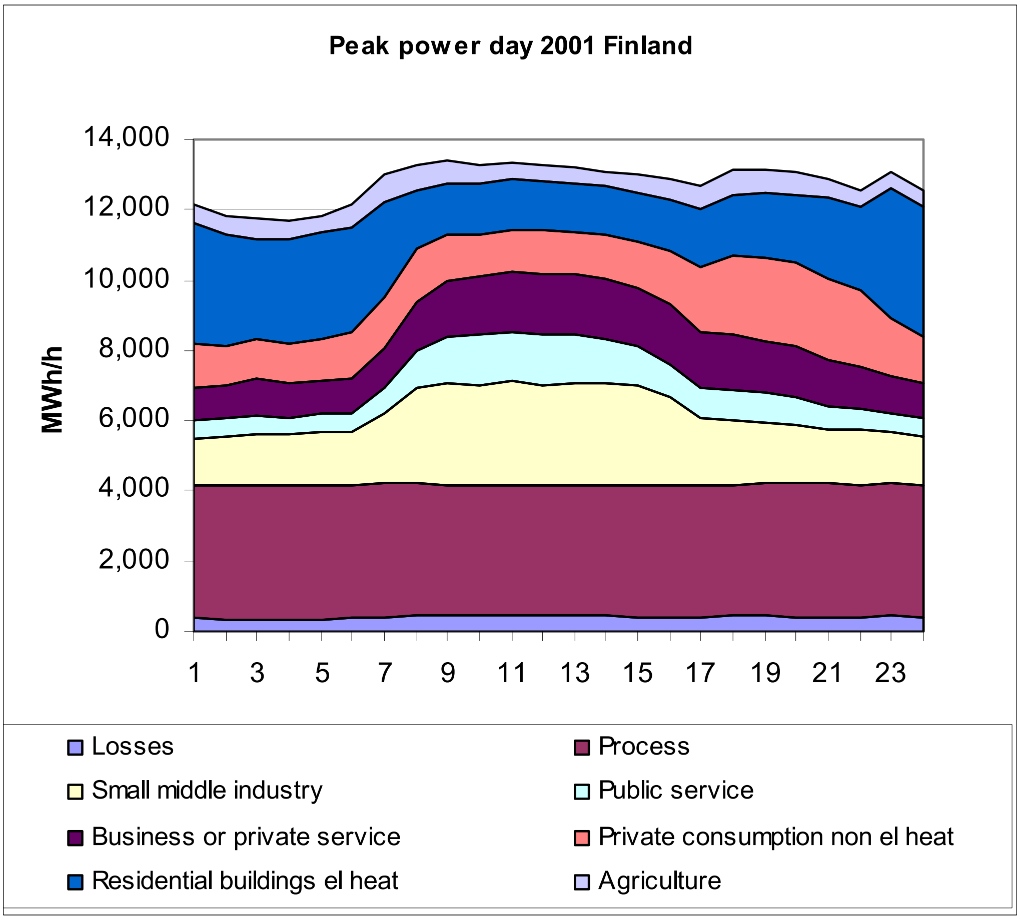

Figure 7.2 Peak day of 2001 for Finland, 5/2-2001 at 10 o'clock 13.4 GWh/h. Temperature: –21.1 Centigrade

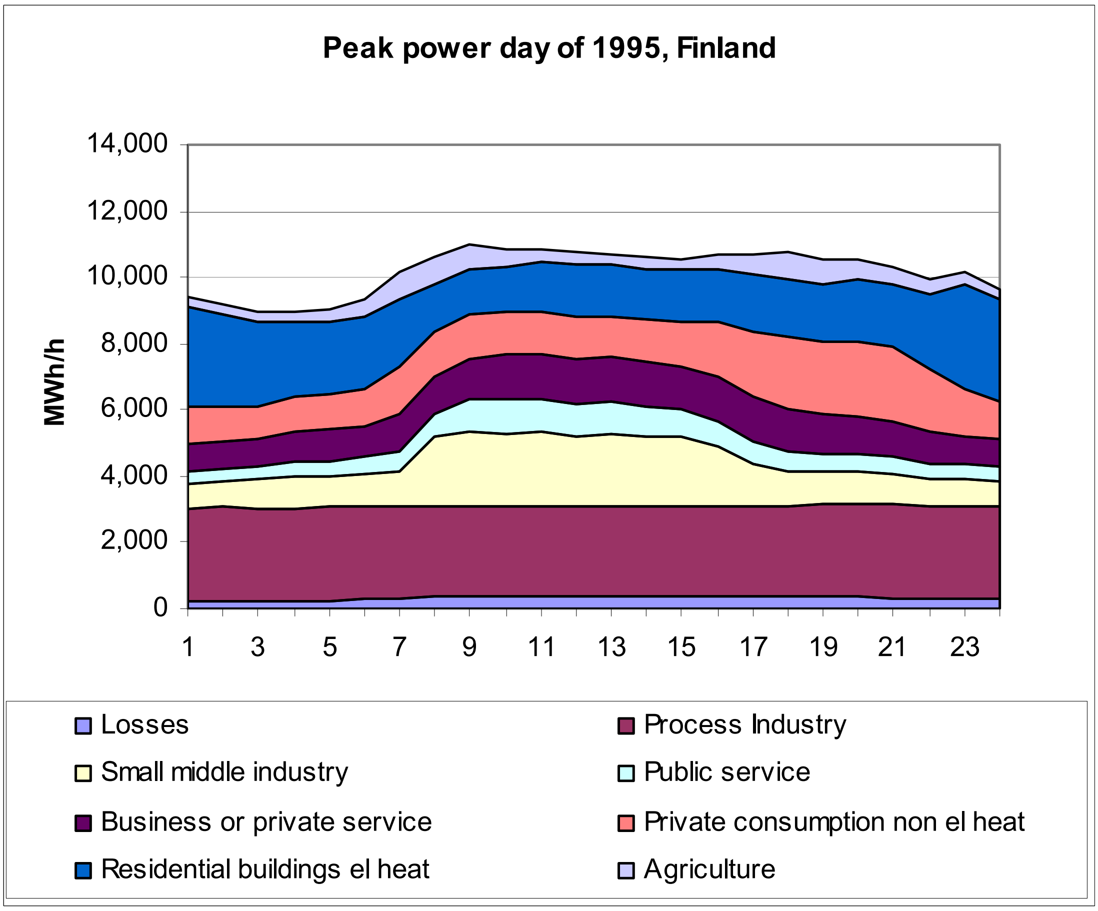

Figure 7.3 Peak day of 1995, at 10 o'clock, 10.97 GWh/h. Temperature: –15.3 Centigrade

8 Sweden – load changes since deregulation

Changes of power at peak hour since deregulation

Results from simulations based on annual energy demand statistics from 1996 and 2001 indicates that since 1996 (before deregulation) the share of power demand of the industry sector has shrunk from 41% to 31.9% (-9.1%), and the share from the public service sector has grown from 18.6% to 19.2% (+0.6%). Data also indicates that the share from Non-prioritised load (el. boilers) is 0% in both years. The share from residential customers has grown with 8.2%. Agriculture has shrunk from 3.0% to 2.5% (-0.5%).

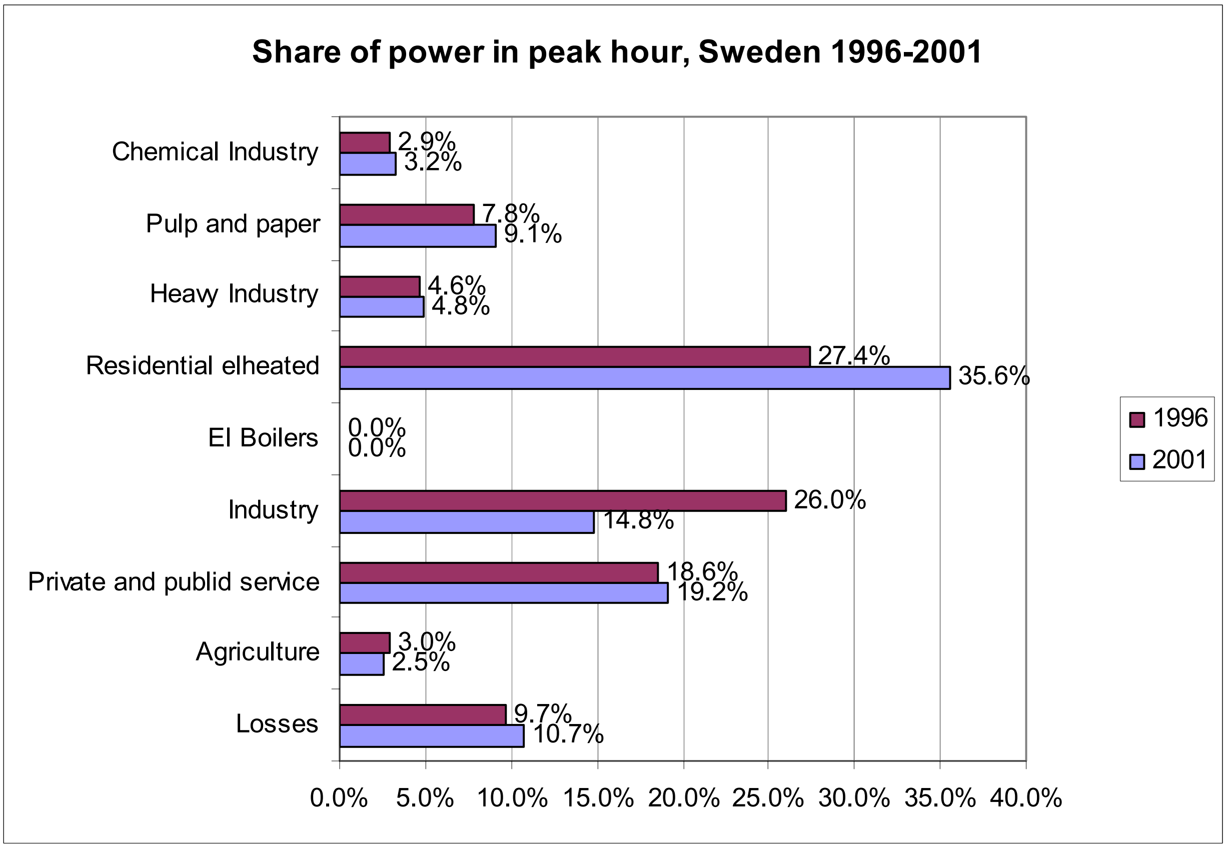

Figure 8.1 Share of power at peak hour in Sweden. A comparison of data from 1996 and 2001

8.1 Peak day curves for Sweden

The Figures shows peak day customer segmentations for Sweden, for 2001 (after) and 1996 (before deregulation). The lower power demand of 1996 must be caused by different number and behaviour of the customers, and could also be a side effect of deregulation. The overall difference is a growth in demand from public service and residential customers. The share of power demand from the industry sector is reduced in the period. In the agriculture sector the actual demand has shrunk.

The peak demand has grown from 25.6 GW to 26.3 GW up with ca 2.7%.

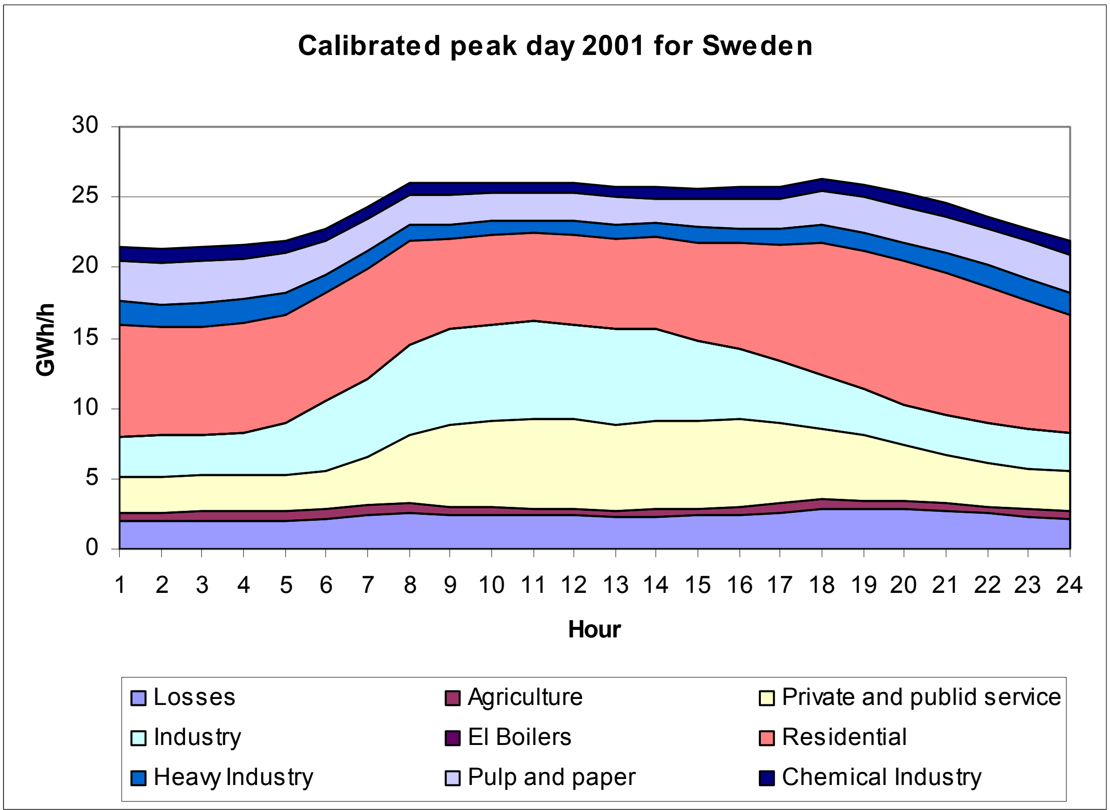

Figure 8.2 Peak day of 2001, 5. February at 18 o'clock, 26.3 GWh/h.
Temperature: –14.4 Centigrade

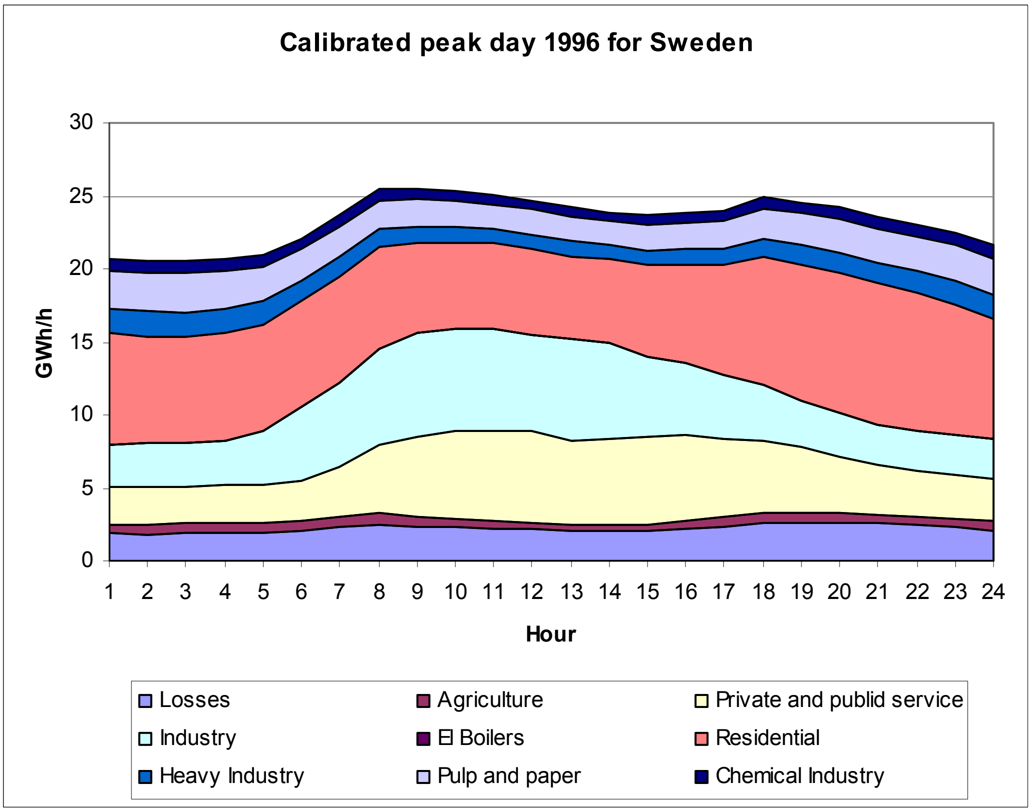

Figure 8.3 Peak day of 1996, 7. February at 8 o'clock, 25.6 GWh/h.
Temperature: –9.6 Centigrade

8.2 Share of annual energy demand

Statistics from SCB [2] indicates that since 1995 (before deregulation) the share of energy demand of the industry sector has grown from 43.4% to 45.4% (+2.0%), and the share from the private and public sector is practice unchanged with 18%. Data also indicates that the share from Non prioritised load (el.boilers) has been reduced with 0.2 % in the period, and that the share from residential customers has shrunk with 1.3%. The agricultural sector has shrunk with 0.3% since 1996.

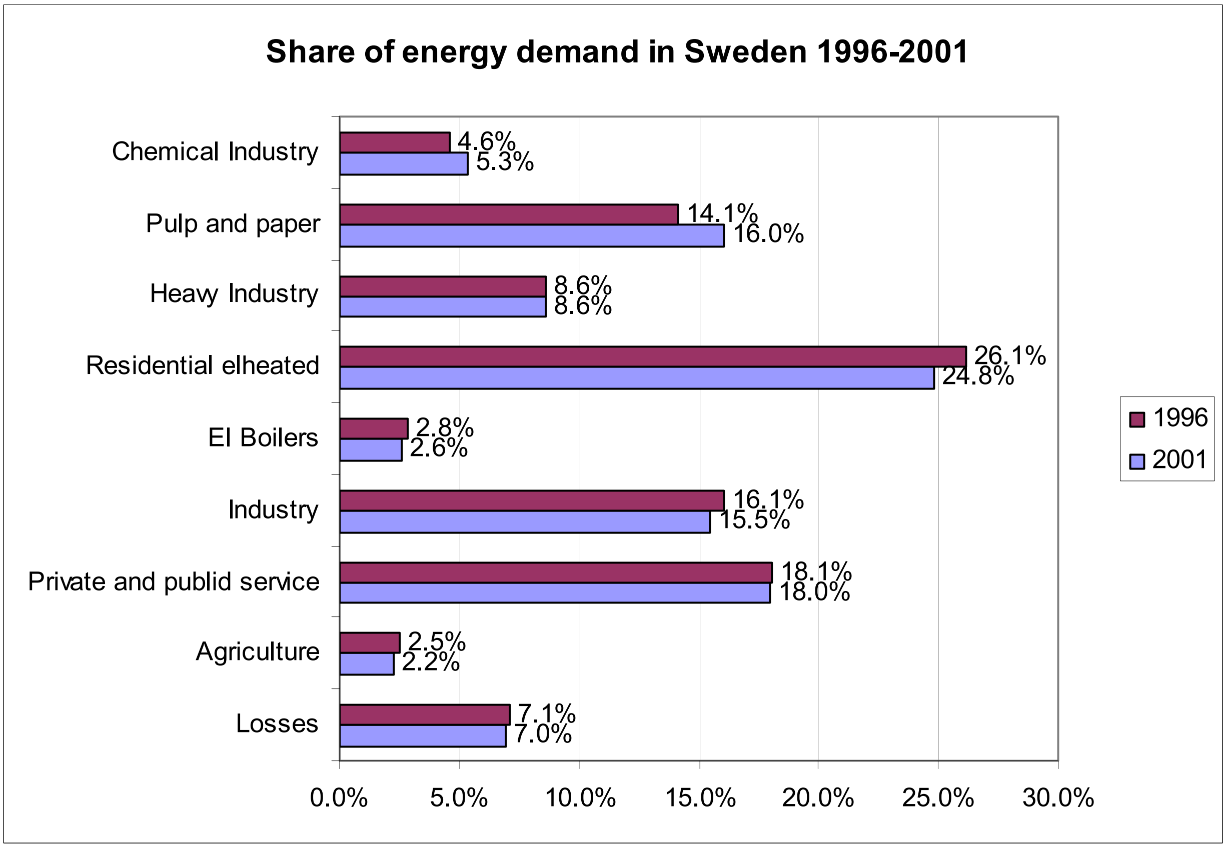

Figure 8.4 Share of annual energy demand in Sweden, a comparison of data from 1996 and 2001

8.3 Annual energy demand segmented into customer types

The Figures shows annual customer segmentations for Sweden, for 2001 (after) and 1996 (before deregulation). The lower energy demand of 1996 must be caused by different number and behaviour of the customers, and can be a side effect of deregulation. The overall difference is a growth in demand of the industry sector. The share of demand from the domestic sector is reduced in the period.

The total annual energy demand has risen from 142.6 TWh to 150.3 TWh, an increase of 5.4 %.

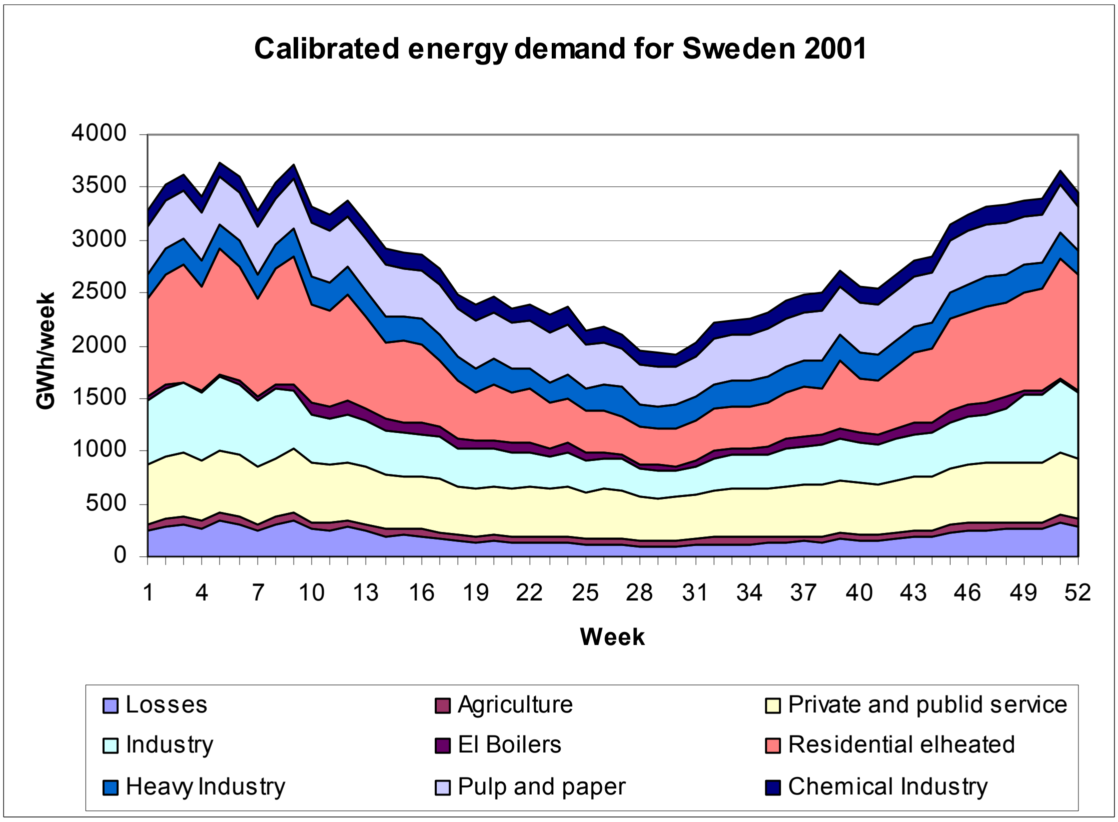

Figure 8.5 Segmented energy demand of Sweden 2001

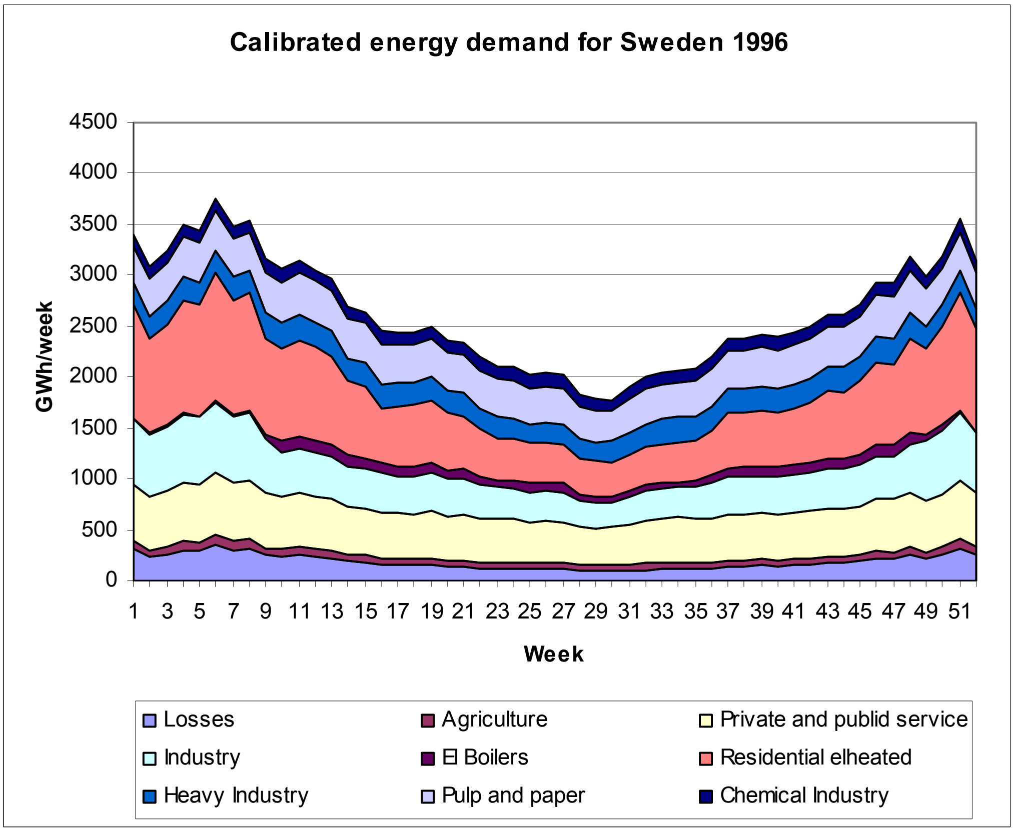

Figure 8.6 Segmented energy demand of Sweden 1996

9 Denmark - load changes after deregulation of 33% of the electricity market

Changes of power at peak hour

Comparing results from simulations based on annual energy demand statistics from 1998 and 2001 shows that that since 1998 (before deregulation) the share of peak power demand of the industry sector has increased 0.3% to 19.1%, public and private sector has increased 1.2% to 27.2%, and residential customers has decreased 0.7% to 41.2%, and agriculture has decreased 0.6%. In both years the peak took place in the evening (17-18 hours).

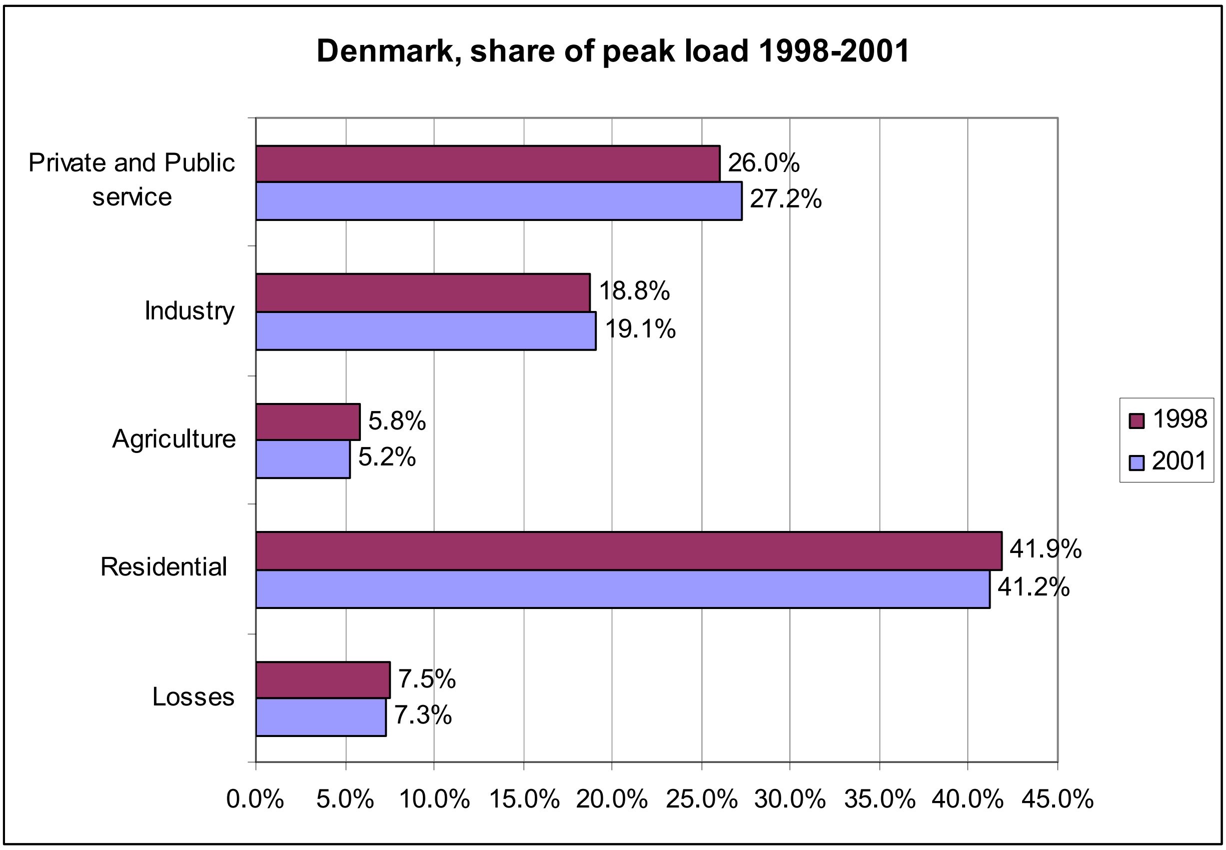

Figure 9.1 Share of power at annual peak hour in Denmark, a comparison of data from 1998 and 2001.

9.1 Peak day curves for Denmark

The Figures shows peak day customer segmentations for Denmark, for 2001 (after deregulation of 33% of the total energy sales) and 1998 (before deregulation).

The peak demand was nearly equal the two years with 6.35 GW in 1998 and 6.23 GW in 2001.

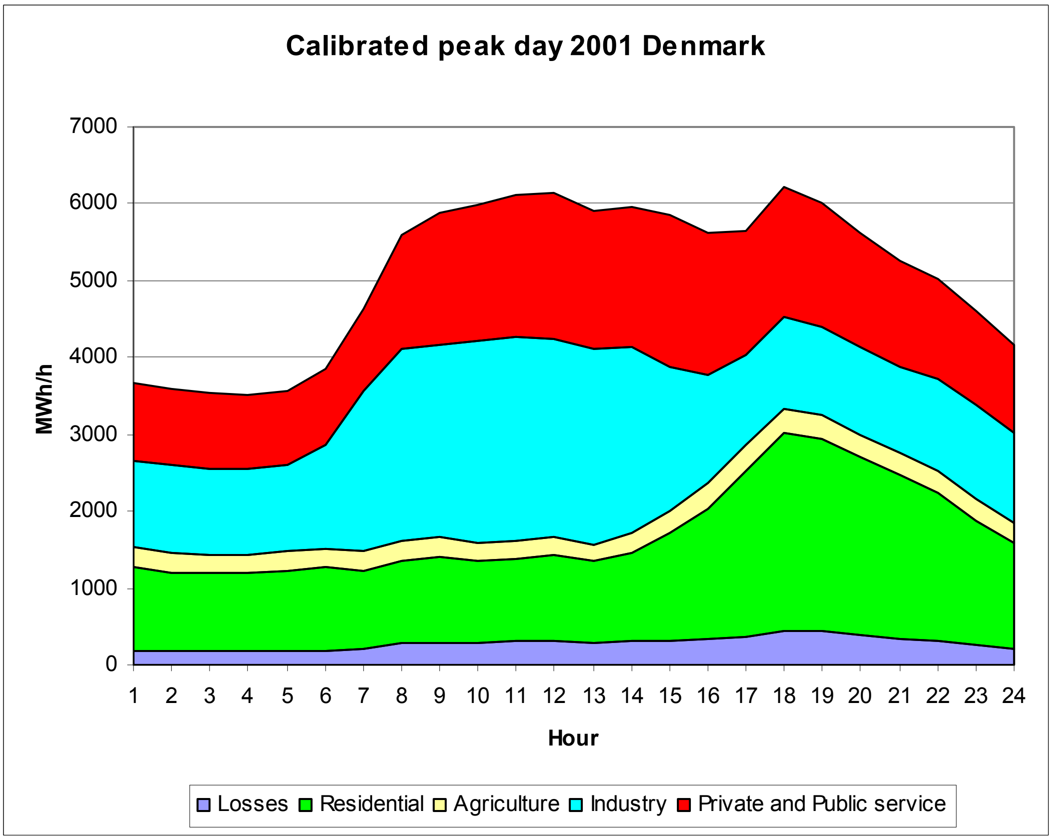

Figure 9.2 Peak day of 2001, 5. February of 6.23 GWh/h. The temperature was –5 centigrade

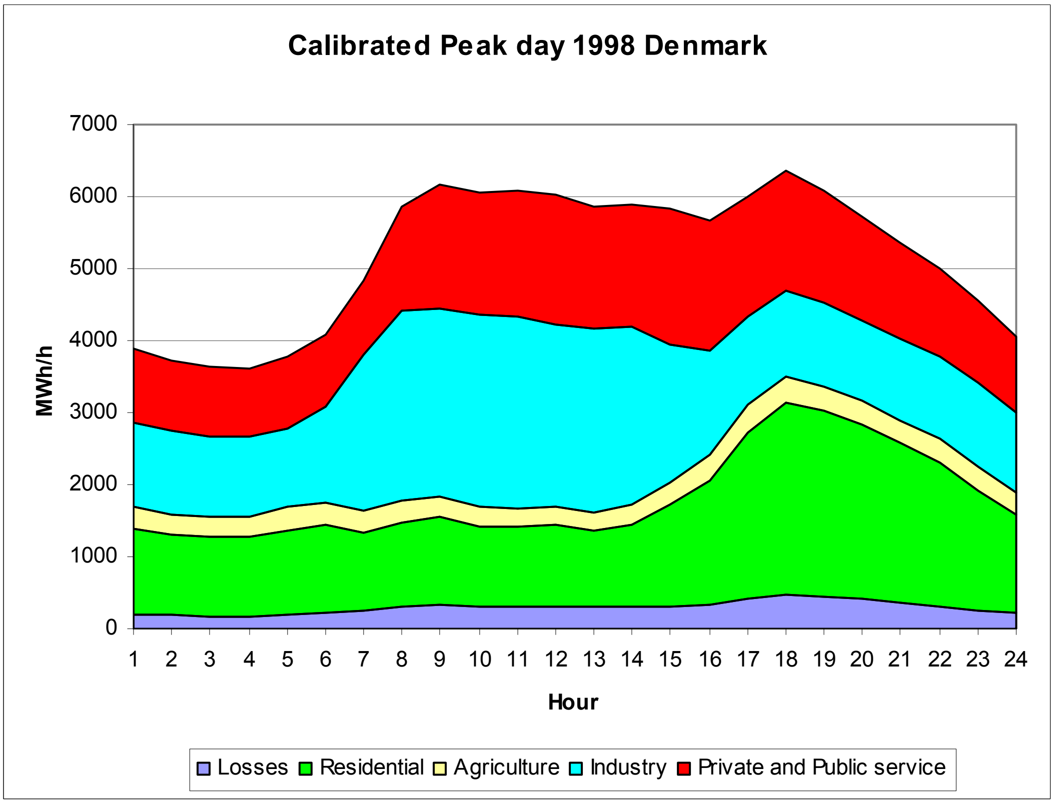

Figure 9.4 Peak day of 1998, 9. December of 6.35 GWh/h. The temperature was –7.9 centigrade

9.2 Share of annual energy demand

Statistics from DST [3] indicates that since 1998 (before deregulation) the share of energy consumption of the industry sector in unchanged with 29.5%, and the share from the private and public sector is practical unchanged with +1.1% (29.3%). The share from residential customers is practically unchanged with 29.2%. The share of the agricultural sector has shrunk with 1% to 6.7% since 1998.

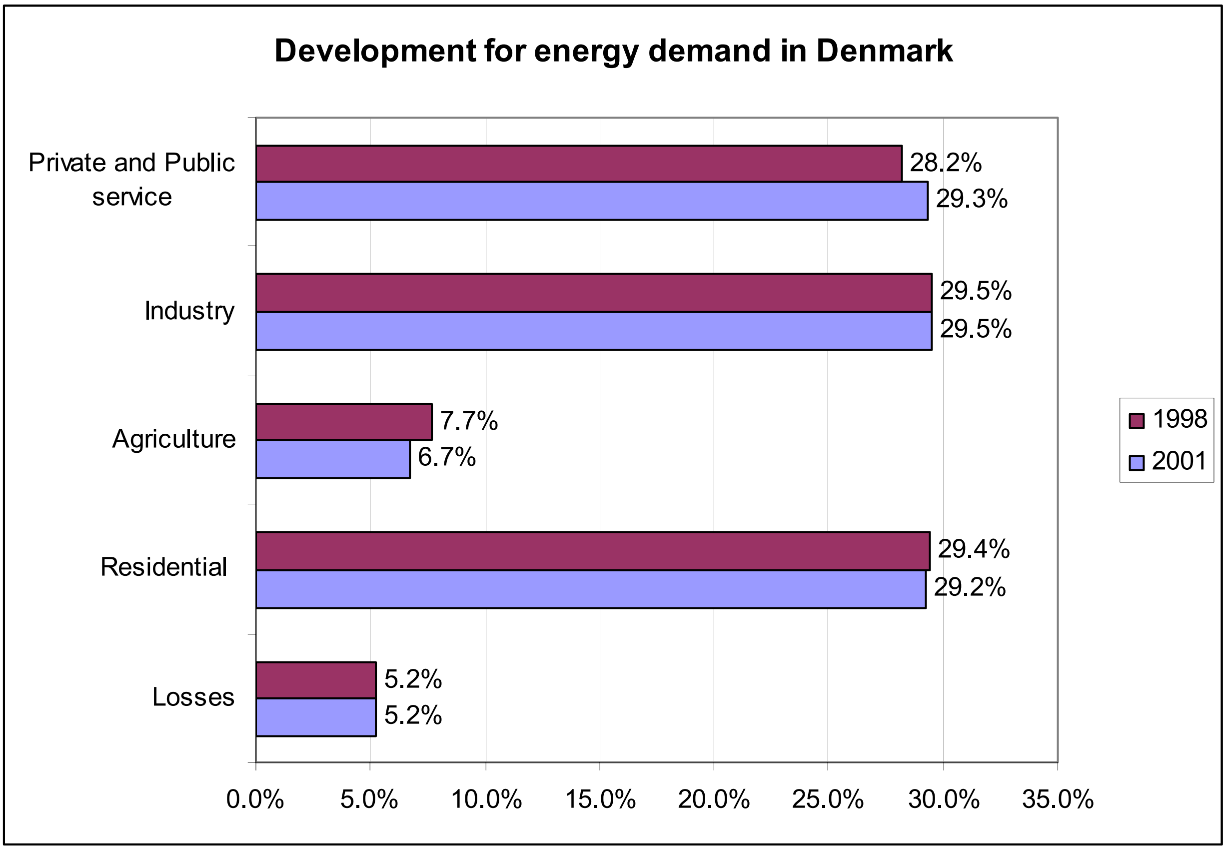

Figure 9.5 Share of annual energy demand in Denmark, a comparison of data from 1998 and 2001

9.3 Annual energy demand segmented into customer types

The Figures shows annual customer segmentations for Denmark, for 2001 (after deregulation of 33 % of the market) and 1998 (before deregulation). The overall difference is only minor changes in demand of most sectors.

The total annual energy demand has risen from 33.647 TWh in 1998 to 34.913 TWh, an increase of 3.2 %.

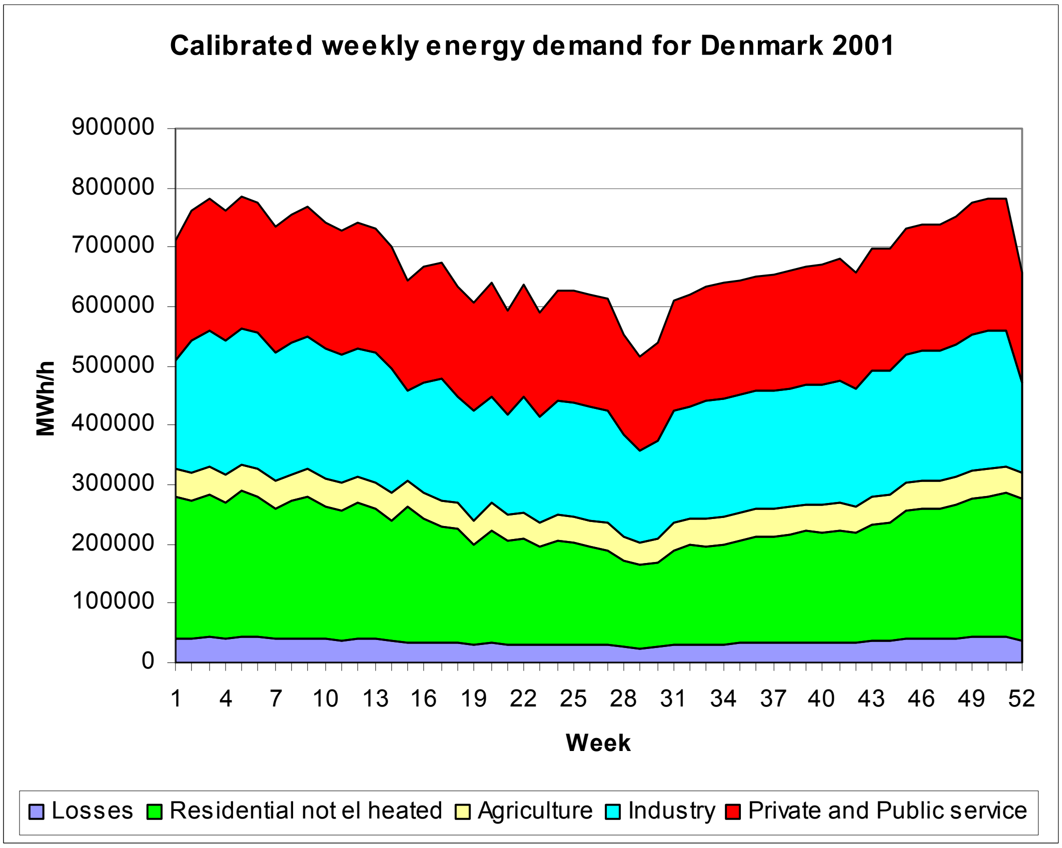

Figure 9.6 Energy demand of Denmark 2001 segmented into customer types

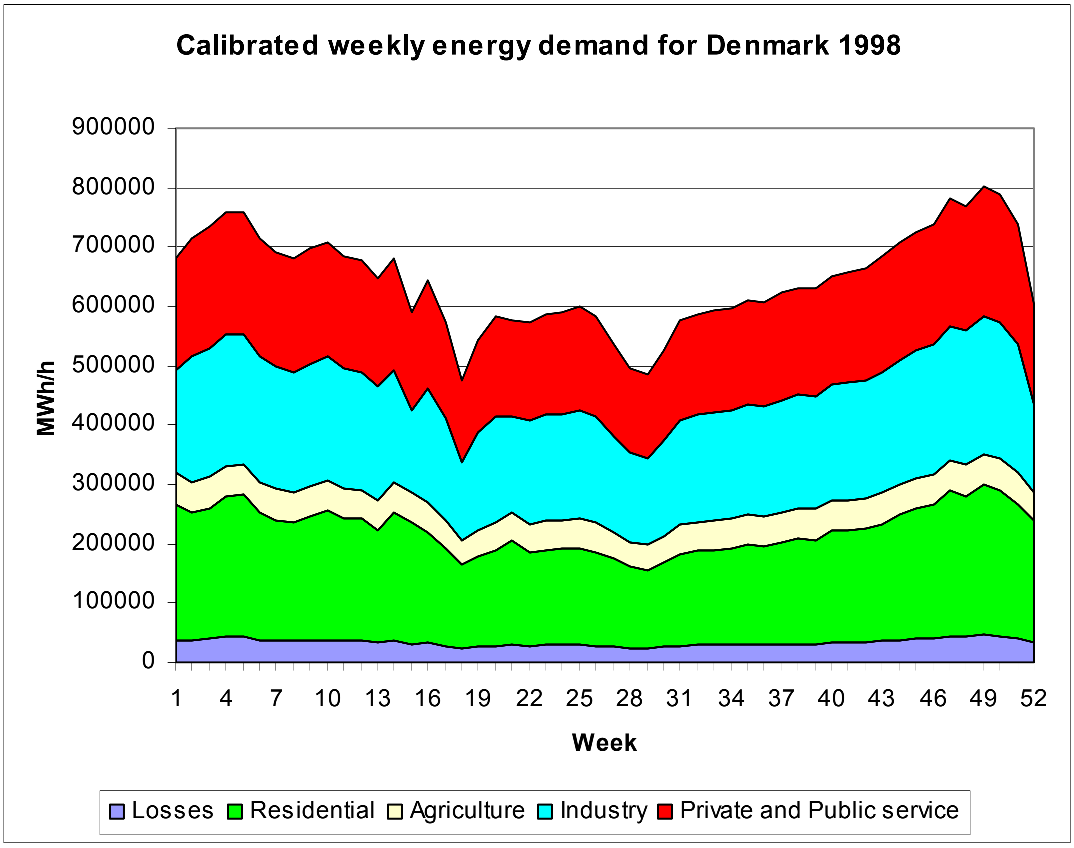

Figure 9.7 Energy demand of Denmark 1998 segmented into customer types

10 Conclusion

The aim of this report is to analyse the impact of deregulation on the load profiles for different customer categories on national and regional level. The system loads from six countries: Denmark, Finland, France, Norway, Sweden and UK have been investigated

The investigated countries are on different stages with regard to the deregulation process. While UK and Norway have more than 10 years of experience with an open electricity market, France is still in the early phase of the restructuring.

The main aspects of deregulation are:

- Unbundling of services into monopoly and competitive businesses
- Opening of the electricity market
- New structures for network tariffs
- Change of supplier options
- Change of ownerships

The analyses show only minor changes in the temperature sensitivity and no radical changes in peak load profile, utilisation factors and distribution of annual consumption and maximum demand of different customer types. It is difficult to relate the registered minor changes to any of these main aspects of deregulation.

References

[1] SSB: Statistics Norway: Statistisk Årbok (Annual Statistics)

[2] SCB: Statistics Sweden: Statistiska Meddelanden 1996 and 2001

[3] DST: Denmark Statistik: Electricity sales per consumer categories

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