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NETWORK PRICING IN THE NORDIC COUNTRIES

- An Empirical Analysis of the Local Electricity Distribution Utilities' Efficiency and Pricing

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Kaisa Kinnunen
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Referent: Prof. Dr. Wolfgang Pfaffenberger
Korreferent: Prof. Dr. Heinz Welsch

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ABSTRACT

The objective of this study is to evaluate the pricing of the local electricity networks in the Nordic countries. Electricity distribution is a natural monopoly and therefore it needs regulation. In the first part of the study, the theoretical backgrounds of cost structure and pricing practices of electricity distribution was studied as well as the most common regulatory methods.

The second part of the study focuses on empirical analysis of the pricing of the local distribution network utilities in Finland, Norway and Sweden. The study is based on the assumption that the utilities set their prices based on their cost. Thus, differences in cost explain the differences in price. Most common explanation of the utilities in respect of higher prices than average is their differing structures. Hence, the influence of some structural factors was studied with an ordinary least squares regression. Because these factors could explain only few percent of the cost or price, it was assumed that inefficiency is the reason for price differences and therefore the efficiency was ascertained with data envelopment analysis. The efficiency study shows that there are large differences in the efficiency between these countries. Based on the efficiency measurement the saving potential was 775-1817 million euros based on empirical information in 2000. Hence, there are large possibilities for efficiency improvements in the Nordic countries that are not yet fully exhausted.

KURZZUSAMMENFASSUNG

Das Ziel dieser Untersuchung ist die Bewertung der Preissetzung der lokalen Stromverteilungsunternehmen in den Nordischen Ländern. Die Stromverteilung bildet ein natürliches Monopol und aus volkswirtschaftlichen Gründen muss sie reguliert werden. Im ersten Teil der Untersuchung werden sowohl die theoretischen Grundlagen der Kostenstruktur und der Preissetzungspraktiken als auch der gängigsten Regulierungsmethoden untersucht.

Der zweite Teil konzentriert sich auf eine empirische Analyse der Preissetzung der Verteilungsnetzunternehmen in Finnland, Norwegen und Schweden. Diese Studie geht davon aus, dass die Unternehmen ihre Preise in Abhängigkeit von ihren Kosten setzen womit Preisunterschiede durch Kostenunterschiede erklärt werden können. In der Regel begründen die Unternehmen höhere Preise mit unterschiedlichen Strukturmerkmalen. Der Einfluss der gewählten Strukturmerkmale wurde mit der ordinary least squares regression method berechnet, wobei sich herausstellte, dass diese Merkmale nur einen kleinen Teil der Kosten oder der Preise erklären können. Es wurde deshalb angenommen, dass die Preisunterschiede eine Folge von Ineffizienz sind. Die Kosten- und Preiseffizienzen wurden mit der data envelopment analysis ermittelt. Die Effizienzbetrachtung zeigt, dass es große Unterschiede zwischen diesen Ländern gibt. Beruhend auf der Effizienzmessung war die Einsparpotenziale in diesen Ländern 775 - 1817 Millionen Euro in 2000. Es gibt also erhebliche bislang noch nicht ausgeschöpfte Möglichkeiten für Effizienzverbesserungen in der Stromverteilung der Nordischen Länder.

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1 INTRODUCTION

The 1990's has been a period of changes for the electricity sectors in most European countries as well as in many countries worldwide. After decades of regulation, it was realised that a liberalisation of the sector would bring along economic gains in form of increased competition and efficiency improvements. The European Union has agreed upon several directives about the details of the liberalisation of the electricity market and its time schedule. After the liberalisation of this sector, regulation is now focused on distribution and transmission of electricity while generation and sales have become competitive business sectors. Regulation of the networks is still needed because there are co-dependencies between the two markets. Networks form monopolistic bottlenecks and thus the accomplishment of functioning competition in the competitive parts of the sector is dependent on the pricing of the natural monopolies, which influences several parts of the society.

The Nordic countries have had a leading role in the liberalisation process. Therefore, they have the longest experience in the liberalisation and regulatory practice. This study gives an overview of the regulation theories, describes the regulatory methods and evaluates their practicability presenting the Nordic countries as an example. This dissertation is organised to move from principle to practice, to make conclusions, and to answer questions in the last part. To the knowledge of the author, this is the first study made of the Nordic countries where the reasonableness of pricing is measured with the same method involving efficiency, which enables the comparison between the countries.

Regulation is generally introduced to secure public interest. The purpose of regulation is to create conditions similar to competition in such parts of the market where competition fails. When choosing the appropriate regulation method the opportunity cost of regulation should be considered, i.e. the cost of market failure should be weighted against the cost of regulatory failure. If the markets are competitive, there should be no regulation. The main problems of the theoretical regulation methods are inefficiency and asymmetric information between the regulator and the regulated utility. The regulation methods can thus be categorised based on their approach to these two problems.

Chapters 2 and 3 consider the general, theoretical concepts related to the national monopolies and regulation. Chapter 2 presents concepts relating to market barriers, network access and market structures as well as relevant cost and pricing concepts of electricity distribution. Chapter 3 discusses theoretical regulation methods and their problems.

In practice, the creation of perfect competition without cost is impossible. All theories face limitations in their practical implementation. There is no "right model" and that is why models must be adjusted to real-life situations. There are differences in the regulatory schemes between the Nordic countries. These Nordic systems are described in chapter 4, in which their advantages and disadvantages will be analysed. The chapter also shortly describes the structure of the electricity distribution in the four Nordic countries.

The focus of this study is on studying the performance of the network utilities based on empirical cost and price information in chapter 5. The question is, whether the utilities are able to set monopoly prices or whether the prices can be considered reasonable. Another objective is to make conclusions about the success of the implemented regulatory schemes based on the results of the empirical efficiency study.

The chosen approach consists of two methods. First, it is assumed that each utility sets its prices based on its costs. Therefore, the differences in prices between the utilities can be explained by the differences in costs. Thus, it was necessary to make conclusions about the factors that explain the costs. According to the electricity distribution industry, the cost (and hence price) differences can be explained by differing environmental conditions and structures. The influence of environmental and structural factors on cost was, therefore, studied with an ordinary least squares method (OLS). Costs of 465 utilities were regressed against selected environmental factors. The result of this study was that the studied environmental factors explained only a small fraction of the cost and that most factors were not statistically significant at all.

Therefore, as a second step, the cost efficiency of the performance of the utilities was studied in order to be able to conclude what kind of cost is efficient for a utility of a certain structure. The efficiency measurement was executed with a non-parametric linear programming method: data envelopment analysis (DEA). Such factors that were significant according to the previous regression study were chosen as structural factors to the study. Based on the efficiency study, it was possible to ascertain efficient costs (input targets) that the utilities should be able to have in order to function efficiently. Besides the cost consideration, also prices were studied with the OLS and DEA methods. The results were similar in both the cost and price study.

Statistical information about the electricity distribution utilities could be found in the internet from the web pages of the respective regulatory authorities. The exception was Denmark, for which the cost efficiency study could not be carried out due to the missing data. The efficiency study reveals that there are large differences in the efficiency between these countries. A cross-country study shows that there are large possibilities for efficiency improvements but the individual country-specific studies prove that regulation methods have been quite successful in introducing similar market conditions within a country.

Based on the efficiency studies, the ex post methods in Finland and Sweden seem to succeed better in introducing efficiency than the ex ante income frames method applied in Norway. Generally, there are still large possibilities for efficiency improvements in the Nordic countries that are not yet fully exhausted.

PART I: THEORETICAL CONCEPTS

2 THEORETICAL CONCEPTS RELATING TO ELECTRICITY MARKETS

2.1 Introduction

The electricity sector consists of business activities that serve different purposes and face different problems. Production and sales (wholesale and retail) of electricity on the one hand and transmission and distribution on the other hand form the main areas of business. In spite of the recent liberalisation of the electricity sector, electricity distribution and transmission remain natural monopolies partly because of very high capital cost and long economic lifetime of capital and partly due to historical reasons. Economies of scale and scope are significant factors in the distribution and transmission of electricity. These, with high capital cost and high investments, lead to an industry structure where a natural monopoly is the most cost-efficient form of market supply.

The physical quality of electricity sets requirements to the business activity. For example, the consumption and production of electricity has to take place simultaneously because the storage possibilities of electricity are limited and expensive. This determines the requirements for the transmission and distribution capacity and for the quality of the network.

In this chapter, the frames are set for the study of natural monopolies. First, some general concepts are discussed and then different cost concepts are studied. Finally, the different ways to price electricity distribution and transmission as well as the problems arising from the pricing practice are analysed.

2.2 Relevant Issues Relating to Electricity Markets

2.2.1 Natural Monopoly

Typically, electricity markets have been *natural monopolies* and, in spite of the recent liberalisation in the electricity sector, electricity distribution and transmission will remain natural monopolies. A natural monopoly is formed by a market situation where a single supplier can supply to the markets more cost efficiently than two or more suppliers. The reasons for natural monopoly are *subadditive cost*. A cost function is strictly and globally subadditive if

$$(2.1) \quad C\left(\sum_{i=1}^{m} q_i\right) \leq \sum_{i=1}^{m} C(q_i) \qquad \text{, for all } q_1,\ldots, q_m \text{ with} \sum_{i=1}^{m} q_i = q\,,$$

where C is cost and q is production. This equation says simply that the summed up cost of production of one supplier are smaller than the summed up cost of a number of suppliers. (Berg and Tschirhart 1988, pp. 22-23; Knieps 2001, p. 23, Pfaffenberger 1993, p. 51.)

The development of natural monopolies often includes *increasing returns to scale* and *scope*. Increasing returns to scale prevail if a proportional increase of all input factors cause a more than proportionate increase of all output components. Economies of scope on the other hand present a special case of cost subadditivity: if simultaneous production of goods or services in one company is cheaper than when these products are produced in different companies, economies of scope prevail. Both of these economies play a significant role in the electricity distribution industry. (Knieps 2001, pp. 24-25.)

Perner and Riechmann (1998, p. 42) discuss the advantages of the network of natural monopoly firms. They argue that economies of scale lead to cost savings because the joint use of the transport infrastructure enables larger production facilities. In addition, the reserve capacity of production can be smaller because there are several producers in the integrated network. The mixing of different load profiles in the grid makes a better utilisation of the installed capacity possible. Furthermore, free capacities can be used to provide more users with electricity, which reduces the investment risk. The meshed network of power producers and customers enables the supply from the nearest injection or discharging point, which reduces losses in power transport.

2.2.2 Contestable Markets

A concept of *contestable markets* has relevance in the economic theory of natural monopolies in the case of a vertically integrated company because it enables the analysis of a monopoly situation with pressure from possible new entrants. In contestable markets, the natural monopoly might not be sustainable, if its cost structure enables other firms to gain profit by entering the market. (Gunn and Sharp 1999, p. 395.) Baumol et al. (1982, p. 5) define a perfectly contestable market as "... one that is accessible to potential entrants and has the following two properties: First, the potential entrants can, without restriction serve the same market demands and use the same productive techniques as those available to the incumbent firms. ...Second, the potential entrants evaluate the profitability of entry at the incumbent firms' pre-entry prices." The first property of these markets excludes the possibility of market barriers. The market can be contestable and a natural monopoly, if entry is reversible with no or inexpensive cost. In the contestable markets, a monopoly company can therefore earn zero profits and has to function efficiently because of the possibility of new entrants. (Baumol et al. 1982, pp. 5-6.) The natural monopolies are usually regulated and a basic regulatory principle states that when there is competition in the markets regulation should be abandoned. Thus, in contestable markets there should be no regulation.

Gunn and Sharp (1999, p. 395) state that liberalised electricity sector, especially the regulated electricity distribution industry, has the two features that characterise contestable markets. First, there are no barriers of entry. Second, the incumbent firm is not allowed to raise its prices when there is a threat of entry of a competitor.

Sunk costs also play a role when determining if the market is contestable. Baumol et al. (1982, p. 7) state "when entry requires the sinking of substantial costs, it will not be reversible, because the sunk costs are not recoverable." Therefore, entry can be assumed reversible and markets contestable only if operations require no sunk cost. Thus, in the electricity network business the markets are *not* generally contestable. This speaks for the need of regulatory actions in order to secure the functioning of competition at the related competitive markets.

There are some special cases where competition might occur, e.g. when an industrial plant is located near to a power plant and it is cheaper for it to build a connecting power line directly to the plant instead of buying the distribution service from the network utility. Such cases put the network utility under pressure to maintain its network prices at the level of marginal costs of building a new line. Competition might also occur in cases when industrial plants are located between the areas of two network utilities, so that the plant can choose its electricity provider. These special cases might help also the other industrial plants or companies to buy their electricity at marginal cost prices if it is prohibited to discriminate between similar customers. Still, there cannot be an area-wide threat of entry. Moreover, these special cases do not influence pricing in the household sectors, since the households usually do not have such negotiation possibilities.

2.2.3 Market Barriers

The concept of *market barriers* (also *entry barriers*) becomes relevant in a situation where there are dependencies between two markets. Thus, it is a question of dependencies between the downstream and upstream markets. This is exactly the case in the electricity sector, where the competitive downstream production depends on the upstream distribution monopoly. The concept of market barriers concentrates on the investigation of the comparative advantage and the market power of an incumbent company compared to a potential newcomer. According to Bain (1968, p. 253) the incumbent firms can, due to market barriers, continuously set their prices above the level of minimum average cost without the risk of new entrants. This causes inefficiencies and welfare losses in the markets. This and the fact that entry barriers hamper down-stream competition explain why regulators are striving for the exclusion of such barriers.

According to Stigler (1968, p. 67), the advantages of an incumbent company are induced by cost asymmetries between companies. He defines a market barrier as "a cost of producing ... which must be borne by a firm which seeks to enter an industry but is not borne by firms already in the industry". Bain's (1968, p. 252) definition for the condition of an entry barrier is "the extent to which, in the long run, established firms can elevate their selling prices above the minimal average cost of production and distribution...without inducing potential entrants to enter the industry." Baumol (1995, p. 264) defines a disallowable entry-barrier cost as "any cost that an entrant must incur simply as a result of the fact that it was not first in the markets".

When considering economies of scale Knieps (2001, p. 18) interprets Stigler's idea in a manner that a market barrier does not exist if the inputs of production are available in the same terms for both the incumbent and potential market actors. Therefore, the economies of scale play no role as long as the newcomer has the same cost function. In addition, capital costs are irrelevant as long as both firms can obtain the required production factors with the same conditions. Baumol (1995, p. 264) states that the scale economies do not necessarily create an entry barrier or increase its height. For example, the second entrant may be larger than the first and therefore benefit from its size. The effects of economies of scale on cost are beneficial to customers, if they get a share of the benefits generated by scale economies. The main cause for market barriers is therefore *the denied or hampered access to the input factors*. In the electricity industry, the distribution of electricity can be seen as an input of the service of providing the customer with electricity. Therefore, for example, a very high entry fee to the distribution network can be considered a market barrier to a disadvantage of an independent power producer.

However, Knieps (2001, p. 19) points out that there are barriers that meet both the newcomer and the incumbent firm and still, according to Stigler's definition, would not be market barriers. Bain (1968, p. 261) refers to these as absolute cost barriers of entry. Therefore, the existence of e.g. a costly license or an access fee to an electricity network reduces the amount of entrants in the markets compared with a situation without an access fee. For an incumbent company this cost is not relevant any more because it is a sunk cost but a potential entrant has to consider this when evaluating whether to enter the market or not.

In this subchapter, attention was focused on the undesirability of market barriers. However, in the history of electricity supply authorities have set access barriers based on legislation. The purpose of these barriers has been to avoid inefficient cost doubling, which would have been the case in the past, because building a power plant or a power transport facility was much more expensive than nowadays. Another, a more important aim of the public authorities was to secure the necessary and sufficient supply of electricity to the whole service area. This was very important for the favourable development of the industry and for the construction of the present infrastructure. Such considerations do not play a large role in the western societies nowadays.

Instead, the objective has been to deregulate and widely open the electricity markets for competition. Naturally, the security of supply of electricity is now more important than ever because our societies are more dependent on good quality electricity than ever before, but the liberalisation process is expected to have no negative effects on the security of supply.

2.2.4 Network Access

While considering market barriers in the earlier section, now the same issue is looked at from another point of view. Regarding *network access,* a distinction can be made between monetary access conditions and other conditions. Monetary access conditions refer to prices that power producers and customers have to pay in order to get the right to use the grid. These prices are collected so that the construction and the cost of using overhead lines, underground cables and power stations will be compensated to the network utility. Other access conditions refer e.g. to technical conditions of the line connector, the physical characteristics of the injected and distracted power, the details of the connection contract, metering services etc. In most countries, there is a set of complicated rules and regulations (*grid codes*) to manage these conditions. (Perner and Riechmann 1998, p. 43.)

The general criteria for conditions of the monetary network access state that access prices should be non-discriminating, fair and transparent. They should be based on the true cost of the maintenance and upgrade of network and be practical and simple. They may also include a signal or a steering function to increase the efficiency of the grid use. The principle that the firm pays the cost that it has caused is logical but sounds simpler than it is because the allocation of cost to the individual customers is difficult. (Perner and Riechmann 1998, p. 44.)

2.2.5 Prevailing Market Structures

The structure of the companies operating in the electricity markets has influence on the functioning of the markets. A v*ertically integrated monopoly* is a company that is active in the monopoly part of the market and acts in other areas of business operations as well. Thus, it is a producer and seller of electricity as well as the operator of the distribution and/or transmission grid. Vertical integration can be interpreted as “any complete vertical merger or any set of vertical restraints that eliminates the externalities between the upstream and downstream firms...” (Kühn and Vives 1999, p. 576). Vertical integration is a prevailing form of company structures in electricity markets.

Vertical separation (or *disintegration*) represents the opposite situation. In this market structure, production and commercial activities are completely separated from transmission and distribution of electricity. There are also mixtures of these two extremes: for example, only the power production can be set under competition whereas other business areas remain monopolies. This presents the situation of a *single buyer*, in which there are many producers in the market but just one grid company taking care of the distribution, transmission and sales of power. This structure is however disappearing. Therefore, vertical integration and separation are the main forms of company structures in the electricity sector. These different structures are presented in Figure 2.1 below.

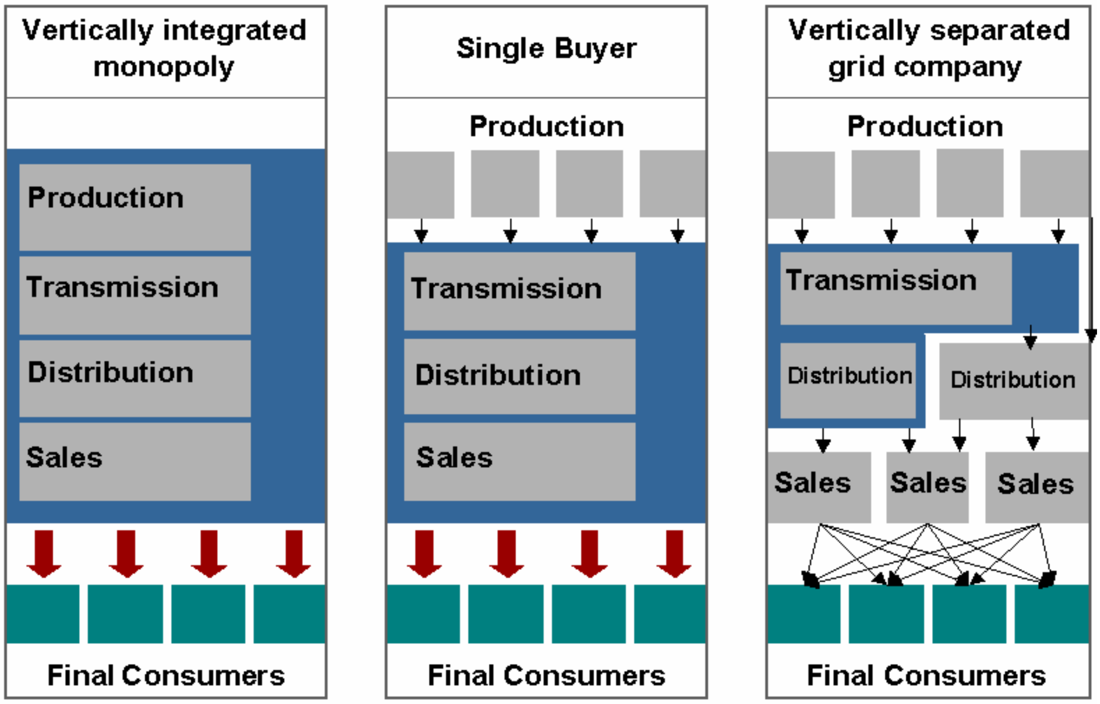

Figure 2.1: Different forms of market structure according to the grade of integration. (Based on: Wild 2001, pp. 17-23.)

Due to the physical characteristic of electricity, production, transmission and consumption have to take place simultaneously. Therefore, it has been beneficial to have these functions all under the same roof in one company. The main reason to integrate business activities vertically is the possibility of reaching synergies through savings in production costs due to economies of scale and by cutting other costs. Vertical integration can be expected to reduce transaction costs. Furthermore, vertical integration decreases uncertainty about the availability of the product i.e. it secures the supply because one firm can manage the operations and has all the necessary information.

2.2.6 Main Problems of Vertical Integration

Vertical integration is an issue much discussed in the economic literature. The main critique against vertical integration is that unregulated vertically integrated companies maintaining and operating the network may impede access of other companies into the markets because they have a possibility to favour their own business units or subsidiaries over other firms. The grid provider may require no charge at all or raise a smaller charge for the use of the grid from its own subsidiaries, which gives them a comparative advantage compared to an independent producer or seller. In a case when there is only little free capacity in the network, the grid provider might choose to transmit or distribute electricity only from its own subsidiaries. In competitive markets, only the most efficient firms produce. If the network owner subsidises its own production units, companies that are even more efficient would not be able to operate, which would lead not only to reduced competition but also to efficiency losses.

Furthermore, vertical integration raises special issues like transfer pricing, predatory pricing, cross-subsidisation, output-mix alterations and input-mix distortions. *Transfer pricing* takes place when the reported costs of a cost-based regulated firm are artificially increased by transferring costs from the competitive subsidiaries. For example, under rate-of-return regulation where the allowed return is based on reported cost, transfer pricing allows the firm to charge too high prices. The extra profits can be shifted from the regulated firm to an unregulated subsidiary. This makes it possible for a regulated monopoly to avoid the regulatory constraint and therefore to earn profits like an unregulated monopoly. *Cross-subsidisation* is a similar problem. In this case, the firm is making losses in the competitive area of business activity but it supports the unsuccessful activity with the profits of the monopoly part of its business activities. (Berg & Tschirhart 1988, p. 434, 464; Baumol & Sidak 1995, p.90; Baumol et al. 1982, p. 27, 351-356.)

Predatory pricing means that the monopolistic firm sets its prices below the short run marginal costs in the competitive part of the market, so that even the most efficient competing firms are not able to survive in the market. The monopoly firm is making losses as well, but it is counting on its possibilities to raise monopoly prices later and to compensate for its losses. All of the above-mentioned issues cause inefficiency in the markets and justify structural regulation. (Berg & Tschirhart 1988, p. 434, 464; Baumol & Sidak 1995, p. 90; Baumol et al. 1982, p. 27, 351-356.)

2.2.7 Vertical Separation

The problems mentioned above in context of vertical integration can partly be solved by the requirement that the firms separate their business activities into monopolistic and competitive operations. Sometimes it is required that monopoly operations are separated into individual firms, but this can be problematic because of ownership rights. Thus, simply a separation in the accounting level is often considered adequate. Without the requirement of (at least partial) separation, the regulatory authority has to solve problems like what is a reasonable transfer price between firms' business units and how to observe it. It might have to judge whether monopolies are behaving anti-competitively by hampering the access of other firms into their markets.

In some countries, the transmission of high voltage electricity has been totally separated into independent companies that are often the owners of the national grids. This is the case in the Nordic countries. The national grid utilities are responsible for the operations of the grid without producing or distributing power themselves.

Léautier (2001, pp. 45-47) has studied the influence of transmission networks to the realisation of competition in the electricity generation. According to him, the capacity of the transmission network has a crucial role in the functioning of competition of the whole market. The expansion of transmission capacity has a two-fold effect. First, cheaper transmitted electricity can substitute electricity that is more expensive. Second, competition will be increased because, if the transmission grid is congested, the transmission prices are high and generators are able to exert local market power. Léautier states that it is in the interest of the vertically integrated utility active in generation that there is enough capacity in the network only for his own transactions. A transmission network enlargement would thus increase the possibilities of the other generation companies to transmit their electricity, which would increase competition. Therefore, from the public point of view, it is beneficial for the society to encourage investments into the transmission network in order to support the competitive market. This market control through ownership takes place also in a situation without vertical integration, but vertical integration sharpens the situation.

Léautier (2001, p. 47) further states, that a vertically integrated utility has more influence on the transmission network expansion. The utility thus prefers less transmission and more congestion so that it can preserve its local market power. Here, the vertically integrated company could plan the expansion of the transmission network strategically or neglect the maintenance of the existing lines altogether in order to maximise profits. Therefore, he concludes that even if the functions of vertical integrated firms were perfectly monitored and the unbundling of business activities was introduced, vertical integration would still be socially detrimental and thus vertical separation should be preferred. Therefore, this is also a powerful argument for independent national networks.

Another issue is the influence of vertical separation on network utility's incentives to develop and maintain its network. Bühler et al. (2002, pp. 15-16) show that under certain conditions the vertically separated utility has smaller incentives to invest in infrastructure quality than a vertically integrated utility would have. This is, however, not always the case. The introduction of downstream competition may also improve incentives. It seems logical to assume that the network owner should be entitled to have some profit from its business activities also under regulation so that it has the incentive to stay in business and maintain the quality of its network. Bühler et al. (2002) further state that a suitable non-linear pricing (like a two-part tariff) eliminates the lacking of adequate investment incentive.

The latest development in the European common market is that in November 2002, the EU Commission has made a proposal to separate transmission and distribution activities from generation and services. It was agreed upon the obligation to implement legal unbundling of transmission by July 2004, while distribution will be unbundled by July 2007. However, the utilities are still allowed to own the separated companies. (Palacio 2002.) Therefore, vertical separation has been considered the best alternative to support competition and market efficiency. In short, unbundling will increase transparency in the market and enable regulators to ensure that no excessive prices are charged for the services of the essential infrastructure. It will prevent the problems like cross-subsidies that are linked to vertical integration.

2.3 Cost Concepts of Electricity Transport

The main problem of the determination of the distribution prices arises principally from the existence of the overhead cost of network operations and upgrading. The overhead cost of electricity transport forms approximately one third of the total cost in the high voltage grid. In the low voltage grid, the share of overhead cost of the total cost is two thirds. (Perner and Riechmann 1997, p. 122.) Another problem in the determination of the accurate cost is the hierarchical structure of the tension levels. The lower network levels must carry the costs of higher network levels thus making the cost determination even more difficult.

2.3.1 Physical Characteristics of Electricity Transport

The physical characteristics of electricity set the frames in the electricity sector. Probably the most important feature of the system is that electric power is not storable. Thus, electricity demand must always equal electricity supply on a momentary basis. Therefore, the task of the network utility is not only to take care of distribution and transmission but also to manage the system control and the other network services. However, also external service companies could provide these services.

Electricity automatically optimises its path in the network. It chooses the way with the smallest possible resistance between injection and discharge points. When the distributed load increases, the resistance of the cables rises more than proportionally and therefore the losses increase. The reverse flows (i.e. flows into opposite directions) compensate each other and therefore reduce network load and losses. Transport losses must be balanced by an extra injection of electricity. (Perner and Riechmann 1997, p. 38.)

Because of the physical characteristics of electricity, every intervention in the network has an influence on the load of the network at least in some part of it. For example, an injection of electricity causes an increase in the load of the local subsystem if there are no reverse flows. This alters the physical characteristics of the whole network and thus other power flows will change their route. (Perner and Riechmann 1997, p. 38.)

The demand of electricity is in practice usually divided into three periods: the peak load, high load and low load period. Characteristic to electricity demand is that different customers have different load profiles. An aggregation of these profiles partly balance fluctuations in the power flow but still there remain peak load periods according to which the network capacity must be planned. The costs of electricity transport differ according to the load situation in the network. When the load is high, the network losses rise, increasing the cost of transport. Still, the cost per kilowatt-hour might be lower when the amount of distributed electricity rises because the overhead cost and the losses are divided with a larger amount of distributed electricity. During the peak load time, however, an increase in the distributed amount might not compensate the cost increase. Because most of the high load times are possible to forecast, the network utility can offer such contracts that guide the power demand into low load times reducing cost in the network. Costs arise also from the need to have reserve capacity in the network in case of sudden capacity failure.

2.3.2 System Control and Other Related Services

The system control is a typical task where distribution, generation and sales of the electricity sector cannot be considered separately. The objective of the *system control* is to match demand and supply of electricity all the time. Thus, the aim is to maintain balance in the network. System control has a very significant role in the electricity network because electricity is not storable. The tool used in the system control is the short-term decision of *power plant release order*, which determines the ranking order of the operated power plants based on their marginal costs. Typical events that need control measures are predictable load fluctuations, non-predictable load fluctuations and power plant failure, long-term demand development and network investment decisions. The predictable demand load fluctuates typically according to time of day, day of week and time of year caused by different demand characteristics of certain user groups and year round climate conditions. The non-predictable load fluctuations and power plant failures pose the main problem. The peak loads and the capacity outfalls must be balanced by employing reserve capacity. (Perner and Riechmann 1997, pp. 48-49.)

It is not likely that several power plants fail at the same time. Thus, the meshed quality of the network alone creates some security into the system. It is not necessary that each network owner build its own back-up power plant. The back up capacity can be bought from where it is the most economic to held. It is considered as a kind of a rule of thumb that the reserve capacity based on the capacity of the largest power plant is adequate in the total meshed network.

Ancillary services are services that are supplied in order to guarantee the good quality of the supplied electricity and the efficiency of the network system. Unipede (1998, p. 6) lists following functions:

- frequency sustainment (control of frequency fluctuations resulting from imbalances between generation and extraction)
- voltage sustainment (acceptable voltage profile by balancing the reactive performance)

- supply reinstatement (technical and organisational measures carried out in case of malfunctions to prevent them or reinstate the supply quality)
- operations management (metering, accounting, administration).

Additional functions are the management of peak demand and provision of reserves or quick-start reserves. Ancillary services can be provided by the network utility or by external companies. These external service providers can even be located outside of the service area. For the stabilisation of the voltage level it is, however, useful that the power plant that is responsible for this service is located in the service area due to the need of high-speed reaction. This might be more beneficial also from the economic point of view.

Thus, the meshed networks induce networking advantages, which Perner and Riechmann (1997, pp. 331-332) list as follows:
- Economies of composition reduce the need to hold network capacity, because a network jointly used by many customers helps to aggregate and balance currency loads.
- Economies of scale reduce the required reserve capacity in the electricity production because electricity loads are aggregated in the grid.
- Economies through transport by displacement because of reverse flows. Network losses can be reduced and the requirement for network capacity is lower.
- A smaller investment risk because the single network components are less specific.

2.3.3 Typical Cost Elements of Transport of Electricity

An international study of the Unipede (1998, p. 6) shows that the most important cost element of the distribution network is the capacity cost of the network. It is formed from the cost of the control stations, overhead lines, underground cables, switchgears and transformers. Operational cost, like personal cost, maintenance, monitoring and operations, is ranked almost as important. According to the study, overhead cost like administration and other cost like insurance cost etc., network losses, ancillary services and taxes play a less significant role.

The overhead cost poses the problem of defining the true cost of certain products or services. The overhead cost can be calculated based on three concepts: cost type accounting, cost centre accounting or product cost accounting. This classification is presented in Figure 2.2 below. *Cost type accounting* collects all of the cost of the activity and financial processes of the company. In the electricity transport significant cost are personal and energy cost, depreciation, interests and material cost like cables, transformers and control panels. (Perner and Riechmann 1997, p 120; Wöhe 1993, p. 1003.)

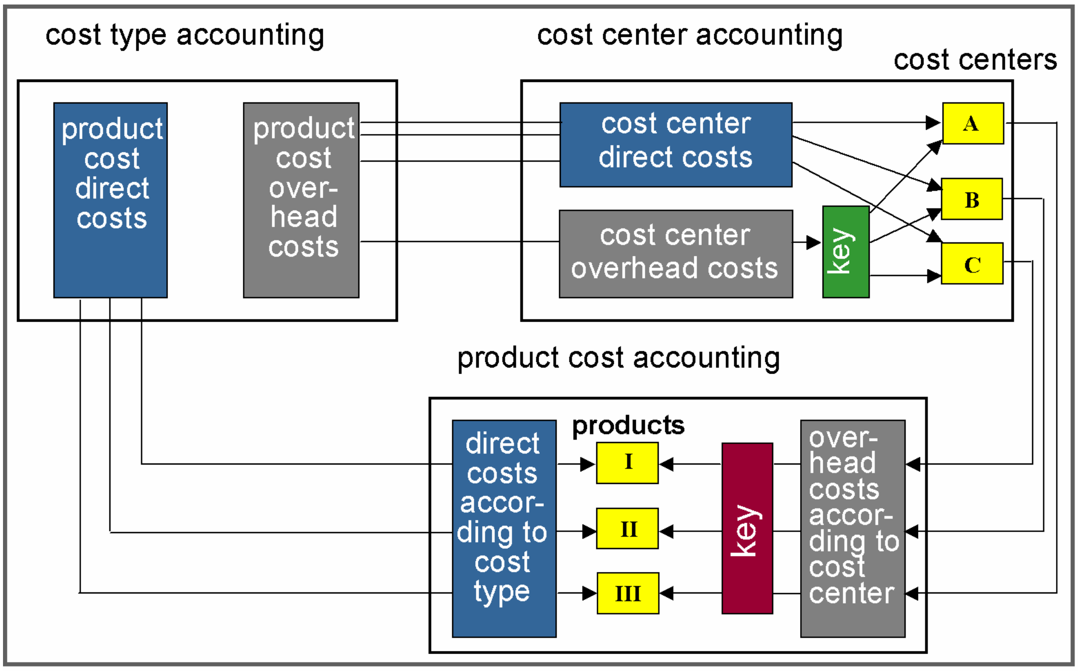

Figure 2.2: General scheme of cost accounting.
(Based on: Perner and Riechmann 1997, p. 121.)

Cost centre accounting describes which cost types can be allocated to certain cost sectors like for example purchase, production, administration and sales. Overhead cost must be calculated to single sites with a key, because it cannot be derived directly. The *product cost accounting* delivers the cost to single products. The unit cost from the cost type accounting will be allocated directly to the corresponding products whereas the overhead cost must be again allocated with a key. (Perner and Riechmann 1997, pp. 120-121; Wöhe 1993, p. 1003.) Electricity at various voltage levels can be seen as separate products which further complicates things.

There are different concepts for the evaluation of capital cost. According to the *real capital approach*, the depreciation of assets takes place based on their historical values. In order to maintain the level of the real capital, the own capital will be calculated in nominal values to include inflation to the calculation. With the *maintenance of real-asset values* approach, the facilities will be depreciated according to their replacement values. The own capital will be paid interest according to the real interest rates. A further possibility is to evaluate assets according to the concept of *present reinstatement value*. This will be used for example as the basis for the calculation of transmission fees according to the method of fictive cable construction. It is also possible to separate between external and own capital and calculate the respective depreciations with different methods. (Perner and Riechmann 1997, pp. 124-125; Wöhe 1993, pp. 1117-1118.)

2.4 Pricing of Network Access

2.4.1 General Principles

The main question in pricing of electricity distribution/transmission is how to price the use of capacity. Further questions that arise from this problem are whether to use distance or nondistance related tariffs, how to price bottlenecks and how to set a price for ancillary services. A few leading examples of price formation will be described in this chapter. The most typical questions in the price formation can be listed:

- Which general pricing model is used? Point-of-connection or point-to-point model? Thus, should pricing include a distance component?
- Which cost allocation model is preferred?
- How can electricity losses be priced?
- How should inputs and outputs be priced?
- What kind of charges – demand, energy or fixed charges – are the most appropriate?
- How can network prices contribute to an open market?
- What is a "reasonable return" for network monopolies? (Unipede 1998, p.1.)

Like discussed in the previous chapters the network can be considered as an input necessary for the electricity supply. Therefore, special attention must be paid to the pricing of the network access. Figure 2.3 below presents general principles according to which a network access fee should be designed. Hughes and Felak (1996, pp. 33-34) consider the principles of the price formation based on the effects on wealth, economic efficiency and on some practical considerations. While considering the implications of network prices on wealth, both the customers' and network utilities' (shareholders') point of view should be taken into account. The economic efficiency requires an efficient use and upgrading of existing capacity as well as enabling the most efficient merit order in the service area. The proposition that the service quality supply should meet demand means that the service quality should be good enough but not better than required by customers. Practical considerations lead to an understandable, transparent and practical structure of pricing system.

In addition, the price should raise enough revenue to cover the cost of the network utility. It should create functioning competition, prevent the abuse of market power and signalise network scarcities. The price formation of electricity wheeling is affected by the industry structure and the physical qualities of electricity as described in chapter 2.3.1 above. An economically efficient pricing system should also promote economic efficiency, which means efficient expansion of transmission capacity, efficient location decisions (long run), efficient use of present capacity and efficient dispatch of existing generating resources (short run). (Baumol and Sidak, 1995, pp. 154-156.)

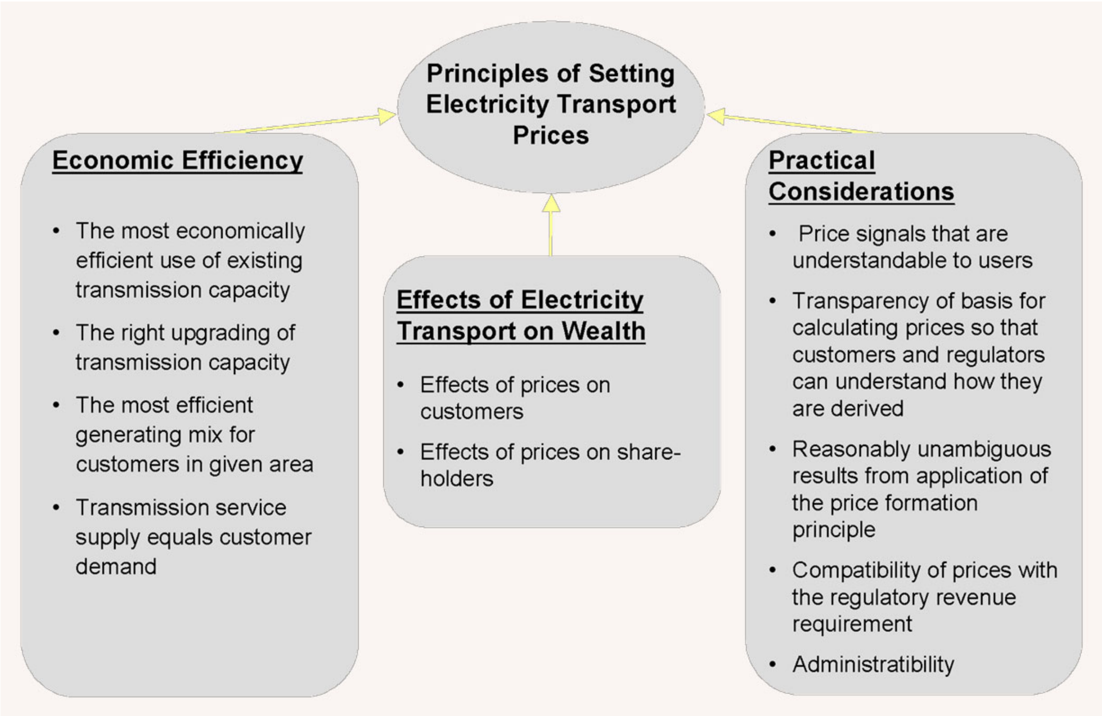

Figure 2.3: Principal concepts for the price formation of the power transport.
(Based on: Hughes and Felak 1996, pp. 33-34.)

Hughes and Felak (1996, pp. 37-38) however point out that the aim of economic efficiency and the utility's aim to receive enough revenue to cover its cost should be seen separately. Such prices that meet efficiency requirements not necessarily meet revenue requirement. The revenue requirement equals total embedded costs (all network costs). Due to depreciation and historical inflation, total embedded costs are lower than replacement costs of the network. When considering the incremental cost, upgrading the network at any given time is more or less expensive depending whether there is a need for major new facilities or not and what the prices for the upgrades are. Cost covering might not lead to an efficient electricity transport capacity.

The network utilities can set the price of transmission based on general terms of access or evaluate it individually. According to the general network access, all potential participants are allowed to access the network in fixed and general conditions as long as the necessary technical requirements are satisfied. The basis is a general, published price system. According to access pricing based on an individual access, each transaction will be priced separately and the access conditions will be negotiated individually between the customer/power producer and the utility. It is also possible that a mixture of these two principles takes place: for example, general rules for access will be adjusted for an individual case. A general access to the networks will be more preferable for the realisation of functioning and healthy competition in the liberalised part of the electricity sector. (Perner and Riechmann 1997, p. 87; 1998, p. 45.)

Table 2.1: Concepts of price formation in electricity networks.

Concepts of Network Utilisation	Cost Concepts	Evaluation of Capital Cost	Translation in the Price System
- utilisation of the total system	- marginal cost	- real capital	- time based
- point-to-point transmission	- incremental cost	- substance	- tariff system with
- tariff zones	- average cost		
- load flow studies			

(Based on: Perner and Riechmann 1997, p. 89.)

There are several concepts for the price formation of the network access that can be combined with each other differently. In Table 2.1 above, the different concepts are roughly classified according to the principles, upon which they are based. Usually pricing methods are based on the utilisation of the network. The concepts can also be based on cost like marginal, incremental or average cost. Alternatively, they can be evaluated based on capital cost. In the practical implementation, many methods are classified according to the point-of-time of the use of network capacity. Usually the prices are divided into parts, which reflect better the cost structure of network utilities.

2.4.2 Point-to-Point versus Point-of-Connection Service

The access prices will often be determined based on the use of the network. There are two principal concepts to determine transport transactions: *point-to-point service* and *point-of-connection service* i.e. general access or participation to the network. According to the *point-to-point* distribution, a third party will be allowed to transmit electricity from point A to point B. The transmission path is defined based on an agreement between the grid utility and the third party. There are various ways to determine the transport path. The two well-known methods are the fictive cable or the contract path methods. (Perner and Riechmann 1997, p. 90; 1998, p. 46; 1999, p. 212.)

According to the *contract path* method, the transmission price is based on the geographical distance of the producer and the consumer, precisely on the use of a certain cable and the transported load. According to the *fictive cable* method, the network utility calculates the cost of transport by using the cost of an imagined construction of new transport line. This approach excludes the third party totally from the benefits of the meshed network. Therefore, the network access conditions of a third party can be considered discriminating. Both of these methods are based on the assumption that the cost of the utilisation of the network will rise when the transmission distance increases. This might be the case when the power flows regularly take place from a certain direction. (Perner and Riechmann 1997, p. 90; 1998, p. 46; 1999, p. 212.) According to the study of Unipede (1998, p. 10) the distance related methods are usually not applied in the pricing of distribution network but rather in the pricing of transmission network.

The main problem in the implementation of the point-to-point method arises from the quality of the meshed networks, where the physical power flows mix and therefore they seldom take place along the path of the economical supply contracts. Instead, there are *parallel flows* along cables that also lead to the consumption point. Physically electricity will be distracted as near as possible to the place where it was injected to the network. Thus, contracts to optimise electricity flows are not necessary, because the electricity flows physically optimise themselves in every case. Sometimes the opposite power flows (reverse flows) unburden the network regardless of the supply contracts (positive externality). The design of the construction of the fictive cable is based on the assumption that there are no externalities. The resulting cost is therefore a *stand-alone cost*, which does not comply with the reality. Therefore, the distance dependent access pricing only approximates the true cost of network activities. A further problem of this method is that the grid users have to inform the network utility of all the injection and discharging customers, which causes high transaction costs in the system. This method would also hinder the development of anonym power bourses like the Nordpool in the Nordic countries. (Perner and Riechmann 1997, pp. 91-99; 1998, pp. 46-47; 1999, p. 212.)

Load flow calculations can be used to find out the real load of the network or of single cables in a meshed transport system. Load flow calculations reveal the true load of the network or of one specific cable caused by electricity transport. This method determines the incremental power flows that are related to transport of electricity and allocates the total cost according to the incremental rate. This model allows for the simulation of the load flows in different parts of the network. Because this method requires a high level of effort in calculation, it is most suitable in the price setting of systems with a general network access and regional differentiated network access prices. Such prices would produce an injection and a discharge price independent of the allocation of their location. In addition, it would treat all customers in an area equally. (Hughes and Felak 1996, p. 28; Perner and Riechmann 1997, pp. 99-101.)

With a *point-of-connection* (general access), the users will be allowed to participate in the total system. The power producers will be able to connect themselves into the grid and freely transmit electricity to their customers within the service area of the grid. The location of the electricity producer in the grid area is irrelevant. The power consumers pay a tariff that depends on the amount and quality of power that they demand and possibly on their location in the grid. (Perner and Riechmann 1998, p. 48.)

A simple possibility to differentiate transport prices is to *establish tariff zones*. This means that the total area of the transport network is divided into zones. The zones can have differentiated prices but within a zone, prices are same for all. This method has the advantage that the regional differences and scarcities in the network can be described without high calculatory effort. In practice, these methods are used in a regulated network access system with a general access to the network. (Perner and Riechmann 1997, pp. 101-102.)

2.4.3 Marginal versus Average Cost Pricing

The capital cost forms the largest single cost entity of the network utilities and therefore plays a significant role in the determination of the network tariff. The cost of management, maintenance and repair i.e. operative cost of business activity must be included in the tariff as well. Scarce network capacity causes costs either because the existing power plant pool has to be modified, which causes deviations from the *merit order* (optimal power plant pool) or because the wires might have to be toughened or replaced with larger ones due to an increasing demand of transmission / distribution. (Perner and Riechmann 1998, p. 43.)

Prices can be divided into two classes according to whether they are based *on average cost* or *marginal / incremental cost*. In the competitive markets, prices are set to equal marginal cost. The marginal cost covers the variable cost of electricity transmission. The marginal cost approach gives network utilities an incentive to utilise capacity efficiently, because prices based on marginal cost give the right signal of the true scarcity of the good. Therefore, it is especially suitable as signal and steering mechanism. Incremental cost is a cost that emerges because of an increase of production by a certain amount. (Perner and Riechmann 1997, p. 103; 1998, pp. 49-50.)

The marginal / incremental costs can be further divided into short run and long run costs. The short-term cost regards capital assets as fixed so that the capital cost of the network is seen as a sunk cost. With the short run marginal cost prices, emphasis is on the efficient utilisation of existing plants, whereas the long run marginal cost is suitable for steering the decisions about the locations of new power plants or energy intensive industrial facilities. The short term marginal costs is formed from the maintenance cost, system operation cost, personal and administrative cost and the cost of short term scarcities in the network capacity as well as the cost of losses of electricity transmission. To be able to calculate the marginal cost of network utilisation, a lot of firm internal information is needed, which makes it difficult to the customer or the regulatory authority to comprehend the basis of the prices of electricity transport. (Perner and Riechmann 1997, pp. 104-106; 1998, pp. 49-50.)

Nodal Pricing is one possibility to determine *short-term marginal cost*. According to nodal pricing, equilibrium is theoretically reached, when the differences of the cost of power production added with the respective transport cost in all points in the network are the same. To put it in another way: the transport cost between two points in the network corresponds to the difference of the cost of power production between these two locations. The transport cost therefore evens up to the marginal cost of production. This means that the tariff is only dependent on the location of the connection. (Perner ands Riechmann 1998, p. 50.)

This method is especially suitable to short-term spot markets, because spot prices reflect the short run marginal costs of electricity production. A problem is that high fluctuating spot prices lead to fluctuations also in the network prices. Another problem arises from high investment cost. The moment the network utility invests in upgrading the network capacity the network prices sink due to a decrease of the network scarcity. Therefore, the network utility has only little interest to invest in the network. To put it another way: the network utility might have an incentive to maintain the network capacity scarce so that the network prices can be driven artificially high and the utility can yield monopoly rents. (Perner ands Riechmann 1998, p. 50.)

Deng and Oren (2001, p. 240) state that nodal pricing would be especially suitable for congestion management, where a central optimal dispatch takes care of congestion management and the transmission charges are determined ex post according to the nodal spot price differences. This price directly reflects market opportunity cost of using a particular transmission line. Hughes and Felak (1996, pp. 31-32) point out that nodal pricing is economically efficient only in some simple radial or linear networks. Whenever there are parallel load flows, the nodal prices would be efficient neither in the short run nor in the long term. In addition, this method might not provide sufficient compensation for the ownership of assets. However, the method can be implemented rather easily in practice, like experiences from Norway show.

Due to the scale economics in the electricity networks, the *long-term marginal cost* often lies below the average cost, which means that the firm would make losses, if the price were set according to the long-term marginal cost. This can be avoided by introducing a tariff system with fixed and variable parts.

In general, prices will be set so that they reflect the cost of the business activity. The variable component of the network fee should be oriented to the long-term marginal cost. These include short-term variable cost and possibly the capital cost. The peak load determines the dimensions of the network capacity. Thus, in the peak load time capital cost can be included into the long-term marginal cost. The dimensions of the system will be determined according to the time of the high load. In this case, a part of the capital cost with the short-term marginal cost will be included to the long-term marginal cost. However, the cost should be lower or equal to the stand-alone cost, since the demander in the high load time should not bear all the cost that arises from the capacity requirement during peak load. Still, he also benefits from capacity and the meshed system quality. In the off-peak time, the long-term marginal cost equals to short-term marginal cost. Thus, the transmission fee should be lower than the average cost. (Perner and Riechmann 1997, pp. 126-127.)

In calculations of the long-term marginal / incremental cost all production factors are considered variable, which enables the assessment of the capacity requirement of the network. Complicated investment calculations and load flow studies are required. Due to the long run perspective of this method, it is afflicted with uncertainties and high informational requirements. All these requirements make this method costly and employ it with a lot of work. (Perner and Riechmann 1997, pp. 104-106; 1998, pp. 49-50.)

The long-term marginal cost methods are based on prognoses about the future production and consumption structures of the company. The long-term marginal cost includes the marginal cost of the increase of the injection and discharge characteristics of the network that leads to a necessary network extension in the future. The problem is that when a single injection (discharge) point increases its supply (demand) this marginal change in the network will be barely noticed. Nevertheless, when the network is functioning at its capacity limit also minimal increases in the network utilisation are sufficient to justify network extension. Therefore, in the practical implementation of calculating particular transmission tariffs, the basis will not be an increase in the marginal cost but an increase of a certain height (incremental cost concept). The long-term marginal cost is thus especially suitable for allocation of specific network infrastructure cost to different users. (Perner ands Riechmann 1998, p. 49.)

The short run marginal cost concepts have an important shortcoming because they only consider variable cost of production. The overhead expenses are not taken into account. An answer to this problem is an *average cost price*. Average cost prices are formed by dividing total cost with some reference value that can be power (MW), work (MWh) etc. Then the price is set to cover this cost. The advantage of this method is that prices will fully cover the cost of the network activities. However, the main disadvantage of this method arises directly from the cost coverage: the prices do not signalise network scarcities. Another problem is that the average cost sink when the amount of electricity transmitted rises. This means that the transport capacity becomes scarcer and thus the prices should actually rise when the load in the network rises so that they would give a right signal to give an incentive to an efficient use of resources. (Perner and Riechmann 1997, p. 119; 1998, p. 49.)

One of these average cost methods is the *postage stamp method*. There are also other average cost methods like the *cable cost method*, the *line-by-line method* or the *boundary flow method*. Often these are based on measuring changes in the load flow according to the load flow calculations. The postage stamp method is based on the idea that a network user profits from the total system when transmitting electricity. According to this principle, all network users should bear the cost of the network. The transport price will be calculated by dividing total cost with the utility's peak load. Alternatively, they can be divided either by the total amount of transported electricity or by the total capacity of the transmission system. The price will be a flat amount per kilowatt or per kilowatt-hour. The network losses will be borne by the party purchasing transport services and will be considered separately. The price is not dependent on the distance or the direction of the power flow. Possible bottlenecks in the transmission system do not influence the price. (Hughes and Felak 1996, p. 27; Perner and Riechmann 1997, p. 138.) An international study made by Unipede (1998, p. 9) reveals that the postage stamp method is the most practised structure of network tariffs in the 25 countries studied.

Deng and Oren (2001, p. 240) criticise the postage stamp method because according to them it does not provide correct economic signals for the use of the transmission network or for the congestion management. In addition, the economic signals for power generation investments in certain locations would not be sufficient. Perner and Riechmann (1998, p. 49) however suggest the opposite. According to them, the postage stamp would be a suitable method to improve efficiency by increasing the network tariff in areas where there is a surplus of supply so that the incentive to invest in power producing capacity in this area will be lessened. The increasing number of power producers in an area where there is demand surplus might lead to reductions in the load of the transmission capacity causing reductions in the network cost. Therefore, in such areas prices could be decreased.

2.4.4 Efficient Component Pricing Rule

The electricity network operations form a so-called monopolistic bottleneck. The monopolistic bottleneck takes place when the network is absolutely necessary for the success of the downstream market and is not supplied in the market by other parties or cannot be doubled in any economic conditions i.e. the market power of these business activities is stable. To enable the functioning competition in the complementary markets, the access to the monopolistic bottlenecks should thus be granted. (Knieps 2002, p. 171.)

According to Baumol and Sidak (1995, pp. 115-138) network access as a good is two-folded. On the one hand, it is an intermediate good, which means that it is a good that is needed to supply for a final good (in case of electric industry the delivered electricity). On the other hand, the network is often used not only by the grid owner itself but also by its competitors. Like already stated above, this creates a need for regulation because the firm can price network access so high that it hampers the competitiveness of its competitors. If the firm sets the price too low (for example for its own subsidiary) an inefficient supplier might be supported, which causes efficiency losses in the markets. The problem of setting a price for transmission according to the *efficient component pricing rule (ECPR)* is to price the grid access so that it encourages the most efficient electricity producer.

The price of a good or a service should not lie below its marginal cost or its *average* incremental cost. The average incremental cost is the difference in the firm's total cost with and without a specific good or service produced divided by the firm's output. The price should include the *opportunity cost* of the firm, which equals to such earnings that the firm forgoes by choosing some specific operation. In other words, the price of a good or service should be set equal to the average incremental cost including the opportunity cost. In case of selling transmission services to a third party, opportunity cost comprehends the yield that the network utility loses by forgoing its own production. It is important to notice that the opportunity cost does not include any monopoly profits or excessive costs caused by inefficiency. This rule enables that the most efficient supplier supplies the market. (Baumol and Sidak 1995, pp. 115-138.)

The advantage of the ECPR is that it eliminates the incentive of the vertically integrated firm to favour the sales of transmission capacity to itself instead of its competitor because the opportunity cost considers this incentive. If the firm sets the transmission price higher than the true cost, in order to hinder a third party access and to increase its own production, then its opportunity cost rises because of the revenue it loses by not selling network access to the competitors. If the price is too low, the firm loses, because its own transmission possibilities will be reduced. This rule thus favours power producers that can produce most efficiently because markets function like under full competition. This will lead to a reduction of the price of electricity transmission sold to end-consumers. Further, this rule reflects the true social opportunity cost of distribution and transmission of power. (Baumol and Sidak 1995, pp. 115-138.)

2.5 Concluding Remarks

In the electricity sector, generation and sales of electricity function competitively but distribution and transmission are monopolistic because only in exceptional situations parallel investments into networks are economically sensible and feasible. A common view is that the different parts of the electricity business needs to be unbundled in order to improve efficiency of the electricity supply.

Economies of scale and scope play a significant role in the sustainability of natural monopolies. In the situation, where some part of the market is competitive and where the other is not and where there are dependencies between the two markets, market barriers and network access conditions gain significance.

The problematic of the determination of the distribution prices arises principally from the existence of the overhead cost in the electric networks. The electric utilities take care of the distribution and transmission of electricity as well as manage the system control and other network services. These generate costs that mostly contribute to overhead cost.

The network utilities can price distribution or transmission based on general terms on access or they can evaluate it individually. According to the general network access, all potential participants must be allowed an access to the network in fixed and general conditions. According to the individual access pricing system, each transaction will be priced separately and the access conditions will be negotiated individually between the power producer and the network utility. A general access to the networks is more preferable so that a functioning and healthy competition can be created in the competitive part of the electricity sector.

There are two main principles to allocate cost: average cost and marginal cost methods. The average cost method seems to be simpler and is more prevalent in practice because it is mostly based on known and reliable data and it guarantees cost recovery. One of the most used average cost methods is the postage stamp method. However, many countries use a mixture of these two methods. Prices can be set based on the geographical distance of production and consumption. The distance-based methods assume that the cost of the utilisation of the network will rise when the transmission distance increases. The distance related methods are usually not applied into the pricing of the distribution network but rather in the transmission network.

In this chapter, some basic issues of the electricity market were discussed. The next chapter concentrates on the regulation of the access conditions to the electricity distribution and transmission networks. Some of the regulation methods also lead back to certain cost and pricing issues already discussed in this chapter.

3 REGULATION METHODS

3.1 Introduction

The electricity sector has been regulated in order to prevent natural monopolies abusing their market power. After the market opening, regulation focuses on the distribution and transmission of electricity while production and sales are competitive business sectors.

Baumol (1995, p. 255) defines the purpose of economic regulation as “protection of the public from the detrimental consequences of inadequacies of competition”. In other words, regulation is introduced to secure *public interest*. This definition means, on the one hand, exclusion of prices that significantly exceed those of perfectly competitive industry, and on the other, prevention of excessively low prices that would hamper competition.

The purpose of regulation is to create conditions similar to competition in such part of the market where competition fails. The competitive market is considered valuable through its positive effects on welfare due to the absence of market failure. Therefore, a commonly acknowledged economic principle is that in fully competitive markets there should be no public intervention. When markets fail, the regulatory authority should intervene (as little as possible) and let the firm choose its operational policy freely after the introduction of the necessary regulation measures.

This chapter presents the most common theoretical economic regulation methods and discusses their practicability and problems. After shortly explaining the principal idea of structural regulation, traditional theories of natural monopoly regulation will be considered in more detail. The chapter will conclude with some newer concepts that were developed to solve the problems of earlier theories.

3.2 General Principles of Regulation

The above-mentioned *public-interest approach* is based on two principles: First, if the market is competitive, welfare will be best served if no regulation is introduced. Second, if market powers do not succeed in creating competition into the markets, the regulator’s task is to induce a situation similar to competition by acting as a substitute to market forces. The public interest theory assumes that regulation can take place without cost and that the regulator has no own agenda and is able to correct the market failure perfectly. (Baumol 1995, p. 255; Knieps 2001, p. 80.) In reality, however, this is not the case. There are always costs in the context of regulation, because of the asymmetric information and because of the administrative effort. Therefore, the authorities must consider the *opportunity cost of regulation*. Hence, they must weigh the *cost of market failure* against the *cost of regulatory failure*.

Regulation is mainly designed to prevent monopoly rents or efficiency losses due to the failure of competition. There are two theoretical approaches: *the normative theory* and *the positive theory of regulation*. The normative theory of regulation is based on the new classical theory of welfare maximisation where the regulator pursues selflessly the good of the society as a whole, whereas the positive theory recognises that also the regulator is one of the interest parties in the markets. Hence, according to the positive theories, the regulator is interested in the welfare of the society only as far as it suits its own interests. (Newbery 1999, p. 136; Pfaffenberger 1993, pp. 232-234.)

The positive theories of regulation are not as formal as the normative theories. The positive theories try to predict the way regulation will work in practice. They focus on the description of the strategic behaviour of the regulator, the monopoly and other interest groups. The role of these interest groups is to provide such information to the regulator that he otherwise might not be able to get. Based on this information the regulatory authority can then set the pareto-optimal price. Thus, the positive theories try to explain the form of regulation as an outcome of bargaining between these various interest groups. The problem of the normative approach is that the public interest is rarely the same as the interest of various interest groups and therefore the normative theories may make poor predictions about the likely outcome of regulation. Still, it depends on the case whether there will be a substantial difference between these two approaches. (Newbery 1999, pp. 136-137; Pfaffenberger 1993, pp. 233-235.)

The positive theory of regulation explains why regulation is beneficial for both the customers and the regulated utilities. On the one hand, the customers require protection against monopoly power and exploitation through too high prices. On the other hand, the monopolistic utilities need protection against the requirements to lower the prices of the "...mass of local voting customers..." so that they can secure the future profitability of their large sunk investment costs. (Newbery 1999, p. 140.)

The normative public interest theory is based on traditional welfare economics that assumes that the maximisation of consumer and producer rent can be reached without causing incentive biases in the operations of regulated utilities. Thus, the regulator tries to find an optimal solution that would maximise the welfare of the society. However, the regulatory constraint does not completely solve the problem that the monopoly tries to maximise its own profit, which does not coincide with the interest of the society.

It has been generally recognised that the basic problem of regulation is asymmetric information between the regulatory authority and the regulated utility. It has also been realised that the regulator can influence firms' decisions about efficiency improvements. The *principal-agent theory* is an answer to this new perception. This theory recognises that the regulated utilities must be granted a profit so that they have an incentive to act efficiently. The profit is limited by the regulation method.

One way to classify the normative regulation methods into a hierarchical structure is shown in Figure 3.1 below. In this chapter, the basic principles, problems and advantages of these methods will be discussed as far as it is relevant to the electricity distribution industry.

The normative regulation theories can be roughly divided into structural regulation and price regulation. In case of structural regulation, the regulator aims to organise the market structure so that there prevail no efficiency losses or possibilities to misuse monopoly power. With price regulation, the prices or the yield of the utilities is regulated. The optimal markets are created as a reaction to price setting according to the regulatory rules. Both of these mechanisms are often used at the same time.

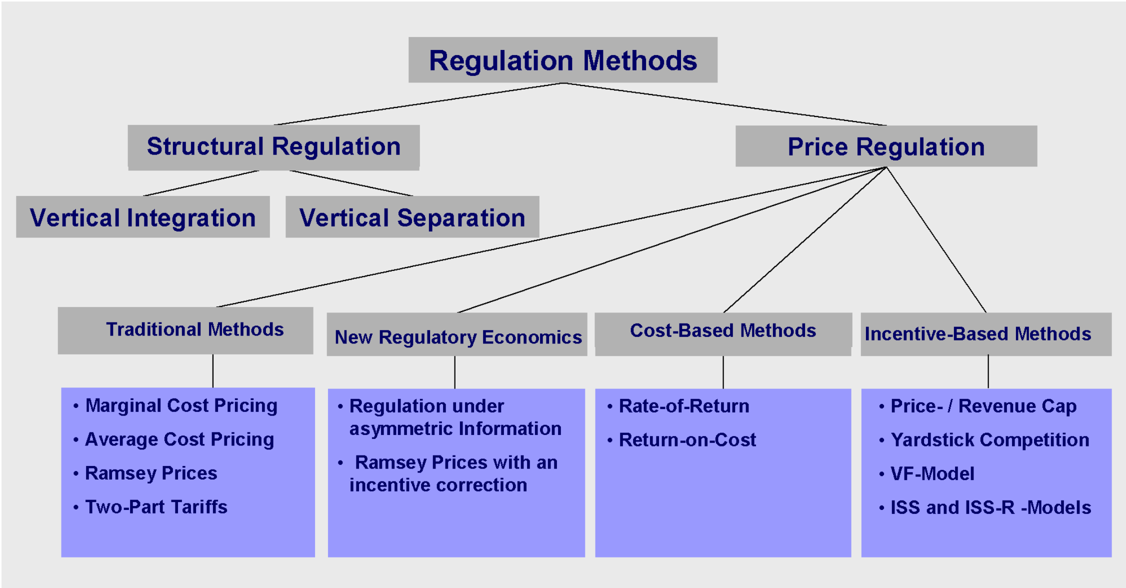

Figure 3.1: Classification of normative regulation methods.
(Source: Own presentation.)

In price-regulation, two different approaches can be identified depending on how they are built. Historically, the most commonly used regulation method has been *bottom-up* regulation meaning that the regulatory authority bases its decisions about a suitable price on the cost information of the regulated company. In t*op-down* regulation a maximum price, a so-called *price-cap,* is set that the regulated company has to accept.

Regulation aims to create prices that
- are cost oriented (they should cover the costs of the network activity)
- are non-discriminating and fair
- have a signal and steering function
- are practical, simple and transparent.

The optimal model should not be subject to short run changes in the regulatory policy, which means that the possible regime should be sustainable regardless whether it is based on structural or price regulation or whether its focus is on preventing profit or creating an incentive to cost reduction. Also in such case that the regulator receives new information, it should not change the regulatory scheme too often. Thus, it should commit itself to the regulatory scheme.

3.3 Structural Regulation

Structural regulation engages the issue of vertically integrated utilities like discussed in chapter 2.2.6 above. The structure of the companies operating in the electricity markets has a significant influence on the suitable regulatory policy. In principle, the decision is to choose between vertical integration and vertical separation.

Lee and Hamilton (1999, p. 241) have considered the welfare effects of using market structure to regulate a vertically integrated company in the case when the downstream markets are deregulated. They analysed how market structures can be used to limit monopoly rents by examining the effects of downstream cost differences on the optimal access price under liberalisation. The study shows that the optimal regulated access prices as well as the final price of the good are higher with vertical integration than with vertical separation.

Song and Kim (2001) have developed another model to study the strategic reaction of vertically integrated firms to downstream entry. They wanted to see whether vertically integrated firms will try to hamper the entry or whether they accommodate the entrant to the markets. They found that there are two possibilities. If the company pursuing to enter the market is inefficient then the entry will be blocked. Respectively, if the entrant is sufficiently efficient, the integrated firms will allow entry. Song and Kim (2001, pp. 194-195) explain this behaviour as an incentive of the vertically integrated company to patronise downstream firms in order to increase their own total sales. Thus, according to their study, the vertically integrated firm would actually support efficiency in the markets.

The prevailing regulatory principle is the requirement of vertical separation at the bookkeeping level. A separation of distribution and transmission from other business activities in firms' accounting has been considered an acceptable compromise to reach transparency and to secure competition in the deregulated business areas of the electricity sector. This requires, however, management unbundling, so that the managers of the business activities are independent from the owners of the vertically integrated company. This ensures that the commercial interest of the integrated company do not influence the decisions of the independent business entities. However, like discussed in chapter 2.2.7 above, this practice is about to be changing because of the new proposition of the European Commission, that distribution and transmission should be separated into independent legal entities.

It should be remembered that the problem of network access remains also with vertical separation. Thus, the structural regulation alone is not sufficient. Additional price regulation is required to guarantee reasonable prices and access conditions of monopolistic bottlenecks.

3.4 Price Regulation

3.4.1 Traditional Regulation Methods

The traditional regulation methods are usually based on three assumptions. First, the regulator has perfect information about the regulated firm and the market. Second, the regulator has the power to set its measures without any extra costs. Third, the regulator has no interests of its own but only aims to maximise the welfare of the society.

3.4.1.1 Regulation Based on Marginal Cost Pricing

Economic regulation is usually used as a tool to contribute to the welfare of the society. Often the most important criterion for regulation is *economic efficiency*. According to this principle, regulation should be introduced in such a manner that no efficiency losses prevail. Another criterion is that the monopolistic firm should not be able to raise *monopoly profits*. Both of these criteria could be easily met, if the price was set to equal the marginal cost of the good or service. This, however, is a problem because often the regulatory authority does not have enough information needed to set the marginal prices.

According to the marginal cost regulation, the regulator sets the price equal to the marginal cost in order to reach *a first best solution* like in the fully competitive markets. This regulation method however relies on unrealistic assumptions. First, it is assumed that all markets are fully competitive except for the one, which is object to regulation. Second, the state can set a levy, which allows it to pay transfers to the firm without any distortions in the markets. The price-setting rule for a case of multiple products is simply:

(3.1) $$p_i = \frac{\partial C(q_1, \ldots, q_n)}{\partial q_i}$$

for all i, where the monopoly charges prices $p = (p_1, \ldots, p_n)$, sells quantities $q = (q_1, \ldots, q_n)$ and the costs of production are $C(q_1, \ldots, q_n)$.

The social surplus can be presented through the social welfare function W

(3.2) $$W(p) = S(q(p)) - pq(p) + pq(p) - C(q(p)),$$

which consists of the consumer and producer rent and where S is an aggregate of the total willingness to pay. The consumer rent is the willingness to pay minus the consumer spending. The producer's rent is the profit that remains when the costs are subtracted from the revenue. By optimising the welfare function, a marginal change in the consumed quantity equals the marginal cost. Further, from a viewpoint of the consumer, a marginal change in the consumed quantity equals the marginal change of the willingness to pay, which equals to the price. Hence, welfare is maximised when the marginal cost equals the price. (Wild 2001, p. 40.)

When economies of scale and scope prevail, a price that equals marginal cost is not the best possible alternative. In the presence of scale economies and high sunk costs, marginal cost pricing would drive the firm out of the market because its average costs lie above its marginal costs i.e. the firm would not be able to cover its fixed costs and would make losses. In such a case, perfect competition is not possible or desirable. Therefore, the marginal cost approach is not suitable unless the regulator pays a subsidy to the firm, which covers its costs. However, this causes distortions in the market, because regulator has to finance the subsidy through higher tax revenue. Hence, other forms of price regulation than marginal cost regulation are suitable. (Baumol 1995, p. 258.)

3.4.1.2 Regulation Based on Average Cost Pricing

The problem described above can be avoided by using average cost prices as a basis for regulation. The regulator sets the prices according to the average cost of the monopoly, which covers also the fixed cost. This is a so-called *second best solution*. The average cost method also removes the need for any transfers from the state and therefore does not cause any distortions in the other markets.

The optimisation problem of the social welfare maximisation is now subject to a zero-profit constraint of the monopoly.

(3.3) $$\text{Max } W(p) = S(q(p)) - C(q(p))$$

$$\text{subject to } pq(p) - C(q(p)) = 0.$$

The first order conditions can be solved with the help of the Lagrange function

(3.4) $$L = S(q(p)) - C(q(p)) + \lambda[pq(p) - C(q(p))].$$

The solution is

(3.5) $$\frac{\partial L}{\partial p} = \left(\frac{\partial S}{\partial q} - \frac{\partial C}{\partial q}\right)\frac{\partial q}{\partial p} + \lambda\left[q(p) + \left(p - \frac{\partial C}{\partial q}\right)\frac{\partial q}{\partial p}\right] = 0 \quad \text{and}$$

(3.6) $$\frac{\partial L}{\partial \lambda} = pq(p) - C(q(p)) = 0\,.$$

It can be directly seen from equation (3.6) that the welfare of the society in the second best world is optimised when the monopoly profit is exactly zero i.e. the price is set equal to average cost. However, this results in a welfare loss compared to the first best solution because the price is higher and the produced amount is smaller than with marginal cost pricing. (Wild 2001, p. 41). In case of multiple products, the problem of this method is how to distribute the average costs on the right products in right proportions. The answer to this problem is Ramsey pricing.

3.4.1.3 Ramsey Pricing

Ramsey pricing widens the previous average cost consideration to a case of multiple products. It is a second best pricing practice to determine a set of prices for multiple products to cover the total costs of the firm with a deviation as small as possible from the marginal cost pricing. According to this principle, prices should be set so that a price increase due to departure from marginal costs pricing influences demand as little as possible. This can be reached by increasing the price of the product that has the smallest price elasticity. This way the loss in welfare and in efficiency can be minimised if the revenue falls due to higher prices. The Ramsey principle means that "... revenue shortfall is covered through smaller increases in the price of the goods whose demands are elastic and through larger increases in the prices of goods whose demands are comparatively inelastic". (Baumol and Sidak 1995, pp. 29-35.)

To be able to calculate Ramsey prices the regulator needs information about the marginal costs of every product and all their price elasticities. It is assumed that there are no cross price elasticities. The optimisation problem is the maximisation of consumer and producer rent subject to constraint of cost recovery. The welfare maximisation problem of the regulator based on the Ramsey pricing method for n number of goods is

(3.7) $$Max W(p_1,\ldots,p_n) = \sum S_i(q_i(p_i)) - C(q_1,\ldots,q_n)$$

(3.8) subject to $\sum_{i=1}^{n} p_i q_i(p_i) - C(q_1,\ldots,q_n) = 0$, where S_i means the willingness to pay for the good *i*. The equation (3.8) is the profit function of the monopoly, which it aims to maximise and which the regulator wants to set at zero.

To get the first order conditions we solve the Lagrange function (compare with equation (3.5)

(3.9) $$L = \sum_{i=1}^{n} S(q_i(p_i)) - C(q_1 \ldots q_n) + \lambda \sum_{i=1}^{n} p_i q_i(p_i) - C(q_1 \ldots q_n) \quad \text{and get}$$

(3.10) $$\frac{\partial L}{\partial p} = \left(\frac{\partial S_i}{\partial q_i} - \frac{\partial C}{\partial q_i}\right)\frac{\partial q_i}{\partial p_i} + \lambda\left[q_i(p_i) + \left(p_i + \frac{C}{q_i}\right)\frac{\partial q_i}{\partial p_i}\right] = 0 \quad \text{for i = 1,...,n}$$

(3.11) $$\frac{\partial L}{\partial \lambda} = \sum_{i=1}^{n} p_i q_i(p_i) - C(q_1,\ldots,q_n) = 0\,.$$

Equation (3.10 can be formed into

$$(3.12) \qquad \frac{p_i - \dfrac{\partial C}{\partial q_i}}{p_i} = \frac{\lambda}{1+\lambda}\frac{1}{\eta_i} \qquad \text{for i = 1,...,n,} \qquad \text{where}$$

$$(3.13) \qquad \eta_i \equiv -\frac{\partial q_i}{\partial p_i}\frac{p_i}{q_i}$$ presents the demand elasticity η of the good i.

The left hand side of the equation (3.12) is the Lerner index. The equation (3.12) indicates that the ratio between the profit margin *(p - MC)* and the price is inversely proportional to the demand elasticity of the good *i*. In other words, it says how much the price lies over the marginal cost (*mark-up*). Therefore, the Ramsey prices are prices whose deviations from the marginal costs are inversely proportionate to the corresponding demand elasticities. Thus, the smaller is the demand price elasticity the higher the mark-up. The right hand side of the equation (3.12) presents the Ramsey index. λ is between zero and ∞ and presents the shadow price of the good or service. If $\lambda = 0$, the budget constraint is not binding. This means, that full competition takes place and the price equals marginal cost. If λ is close to ∞, the right hand side of the equation (3.12) is one and the prices are monopoly prices. (Berg and Tschirhart 1988, pp. 55-57; Laffont and Tirole 1993, pp. 30-31; Wild 2001, pp. 42-43.)

The information requirement is one of the problems also with Ramsey prices. The regulator does not usually have all information that is needed to set a Ramsey price. Another problem specific to the electricity distribution industry is that the demand for transmission and distribution is very likely to be inelastic. The prices of the distribution services would rise substantially, which would act like a market barrier preventing other firms entering the market. This kind of price setting can also be seen as price discrimination.

The regulatory process itself causes a further problem of Ramsey-prices. In the calculations, the demand elasticities are taken as exogenous. However, the demand elasticity of the firms is largely influenced by regulators decisions or by policies affecting existing or potential competitors. For example, the firm's possibilities to secure itself from competition are affected by the way how the market entry and pricing are regulated. Therefore, the firm's demand price elasticity is determined endogenously, which is inconsistent with the earlier assumption. (Baumol et al. 1982, pp. 358-359; Baumol and Sidak 1995, pp. 29-35; Tirole 1988, p. 70.)

3.4.1.4 Two-Part Tariffs

According to Baumol and Sidak (1995, pp. 35-37) another possibility to lessen the problem of having to deviate from the marginal cost pricing would be a two-part tariff. It is a non-linear price, where one part depends on the amount of good or service demanded and the other part is a uniform fixed price that is independent of the consumed amount. (Berg and Tschirhart 1988, pp. 103-118; Tirole 1988, pp. 143-152.)

Laffont and Tirole (1993, p. 176) have presented the two-part tariffs as follows. The form of the tariff for a single product is $T(q) = A + pq$, where A represents the fixed part of the tariff and pq the variable part. The marginal price lies between the marginal cost and the optimal linear price. This method is especially suitable to electricity distribution industry because in this industry the capital cost are high and the marginal cost lie below average cost. It is the most often prevailing pricing practice. A system of tariffs that has two or more parts is applied in all of the Nordic countries. The advantage of the method is its simplicity. For example, if the demand of electricity transmission were independent of the height of the fixed part, then a price rise in the fixed part of the tariff would have no effect in the market. However, in reality this is not the case. A very high price of a fixed (entry) charge would act like an entry barrier and would jeopardise the downstream deregulated competitive market. An additional problem is that also the two-part tariff can be seen as price discrimination. (Baumol and Sidak 1995, pp. 35-37.)

However, this method does not solve the problem of asymmetric information between the regulator and the utility. To be able to set the right variable part of the tariff, the regulator should be able to monitor accurately the marginal cost, which like already discussed above is very difficult. Further, for the setting of the accurate fixed part it should be able to monitor the right and reasonable capital and other cost. Therefore, in the regulatory practice this method is no more applicable than the other traditional methods described above.

3.4.2 New Regulatory Economics

Laffont and Tirole (1993, p. 34) have proposed a new theory for the regulation of natural monopolies. In their opinion, a simple second best -optimisation approach is not applicable to the regulation in the real world. Thus, the new regulation method differs from the traditional regulation methods by acknowledging that the first-best or second-best solutions cannot be reached. Hence, only *third-best* solutions are possible. Laffont and Tirole name three reasons for this: asymmetric information (moral hazard), lack of commitment and imperfect regulators. The main principle of this new theory is that the regulation should include a full description of the firm’s and regulator’s objectives, information structures, instruments and constraints. Furthermore, the regulatory schemes should reflect the real world costs. The *new regulatory economics* of natural monopolies is based on the *principle agent theory* according to which the regulator (principal) offers the regulated firm (agent) contracts in order to set incentives to make the firm act appropriate way.

The purposes of the new regulatory economics can be listed as follows:
- The productive efficiency of the monopoly should be improved i.e. the demanded output should be produced with less cost.
- The prices of the products should stimulate allocative efficiency. In an ideal case, the price should equal marginal cost.
- The regulator organises distribution of efficiency in consumer or producer rent. In general, the consumer rent has a higher priority. (Lewington and Weisheimer 1995, p. 278.)

Lewington and Weisheimer (1995, p. 278) discuss the existence of a mutual dependency between the regulator and the monopolist as a new insight of this method. It is for the benefit of the society as a whole that the monopoly continues to produce. With this *participation constraint,* the monopolist can pressure the regulator in order to reach its own goals. The issue of regulators reliability raises the need for a strong and reliable commitment of the regulator to stand behind its earlier decisions and play rules (*regulatory commitment*). If the actors in the markets do not trust the regulator, they might invest less than optimal.

In the new regulatory economics, it is realised that the regulator is incapable of posing all theoretically possible regulation measures due to several factors one of which is asymmetric information (i*nformational constraint*). The contracts in the electricity business are also often long-term contracts and due to transaction costs it might be impossible to consider all possibilities in one contract (*transaction constraint*) without substantial additional costs. The more difficult the contingencies of the firm are to foresee and formulate in a simple manner the higher the transaction costs will be. Respectively, regulation can only be organised within the existing political, administrative and legal system, which poses a limit (*political and administrative constraint*). There are also limits to scope, instrument and time horizon, which have to be considered by the regulatory authority. (Laffont and Tirole 1993, pp. 1-6.)

Laffont and Tirole (1993, p. 1) name two kinds of informational constraints:

- *Moral hazard* might take place when the monopolist can influence some *endogenous* variables that the regulator is not able to observe.
- *Adverse selection* is a situation where the firm has better information about some *exogenous* variables than the regulator. Adverse selection allows the firm to earn a rent even if its power to influence the regulators decision is small.

The regulator needs information about the sales of the firm as well as information about its cost structure. This information is available only to the firm itself and it has an incentive to transmit false information to the regulator in order to get some advantage from it.

The model of Laffont and Tirole (1993, pp. 168-171) is presented as a situation where the task of the regulator is to create an optimal regulatory policy for a multi-product firm. The regulator is able to observe the firm's cost and produced quantities. The cost function of the firm depends on its technological parameter and on its effort to improve efficiency, which are, however, unknown to the regulator. In this model, the state receives all its revenue from the sales and the firm receives a transfer from the regulator in the height of t as a repay to cover its cost. (For the analytical approach, see Appendix A.)

The social value in this model is formed from the *gross* consumer surplus less the monopolist's revenue from the production, i.e. the *net* consumer surplus and from the social value of the tax savings for taxpayers, which is generated by the sale of the goods. The utilitarian social welfare function is a sum of consumer surplus and the producer surplus. The welfare is composed from the social value of outputs, the total cost of operating the firm multiplied by its shadow price and the social cost of allowing the firm a rent. Laffont and Tirole (1993) reach a conclusion that in a first best world in a situation with symmetric information the marginal disutility of effort to improve efficiency should equal to the marginal cost savings. Thus, the regulator can set rules according to which no disutility of effort takes place or the disutility equals marginal costs of savings. Under asymmetric information, the regulator uses a cost-reimbursement rule to extract the firm's rent while preserving its incentives. Thus, there is an incentive correction associated with the regulator's aim to extract the firm's rent. The argumentation leads to a conclusion that if an increase in output makes it easier for the firm to transform exogenous cost changes into a rent, the incentive correction is favourable to higher prices. (Laffont and Tirole 1993, pp. 168-171.)

The main idea of Laffont and Tirole is thus to correct regulation with an incentive correction. Corresponding to the Ramsey rule optimal pricing requires that the Lerner index of each product should be equal to the sum of a Ramsey term and an incentive correction, where only the incentive correction depends on the cost of the firm. (Laffont and Tirole 1993, p. 200.) The problem of this method is that it is analytically relatively complicated. The method also lacks transparency. Furthermore, the monetary transactions to and from the regulator are not practical in the realisation.

3.5 Cost-Based Regulation Methods

3.5.1 Introduction

Cost-based regulation methods consider regulation as a constraint of the firm's profit maximisation instead of seeing it as a corrective measure to reach welfare maximising prices like the public interest theories. The basic idea of the *cost-based regulation methods* is that prices are determined by equating total revenue and total cost. In order to find out the revenue requirement, the regulator views operational cost (e.g. labour, fuel, maintenance) of some previous period, often a 12 months period. Based on this information it determines, depending on the method, the level of the cost or of the capital stock that is used as a rate-base. As a next step, the regulatory authority chooses the price level in order to equate revenue and revenue requirement. After setting the price, it is fixed until the next evaluation. Thus, prices are not flexible upwards or downwards. (Knieps 2001, p. 86; Laffont and Tirole 1993, p. 14.)

A very significant factor in the design of the regulatory system is *the regulatory lag*. It is the time when the prices are fixed between two regulatory reviews. It has a lot of influence on the incentive properties of the cost-based regulation methods. Although in principle, cost is continuously compared with the firm's revenue or price, the practice is different. The regulatory hearings and the decision making of the authority often takes a long time and therefore the prices often do not exactly match the cost. (Laffont and Tirole 1993, p. 15)

Cost-based regulation methods are largely used in practice. They are based on the earlier insights that the firm is maximising its own profit instead of the profit of the society. The method also recognises that there is asymmetric information between the firm and the regulatory authority. These methods are oriented at the traditional regulation of which the focus is on preventing monopoly rent without attempting to improve efficiency. (Wild 2001, p. 56.)

3.5.2 Rate-of-Return Regulation

The most important cost-based regulation method is the *rate-of-return* regulation. Like discussed above, the principle of the rate-of-return regulation is that prices cover the cost of the monopoly and that there is a fair return to capital. The regulator sets the price equal to the average cost of the firm to avoid losses, which would be the case with marginal cost pricing in natural monopolies. A share of investment cost is also included to this average cost as well as a reasonable return on investment. The cost also includes opportunity cost. Thus, the firm is guaranteed to get its cost covered.

The rate-of-return regulation in a multiple product case can be presented as follows. The problem is to maximise the profit function:

(3.14) $$Max \prod(L,K) = p(q)q(L,K) - wL - rK$$

$$\text{subject to} \quad \frac{R(L,K) - wL}{K} \leq s \quad ,$$

where r < s < m, which marks the rate-of-return constraint. *L* is labour, *K* is capital, *R* is revenue and *R(L,K)* the revenue function, *w* is the price of labour (wages) and *r* is return on capital (interest) of the competitive market. *s* stands for allowed return on capital and *m* for return on capital of the monopoly. (*wL + rK*) present the cost function. Because *R(L,K) = p(q)*q(L,K)* the constraint gives:

(3.15) $$p = \frac{wL}{q} + \frac{sK}{q}.$$

Thus, in the single product case the price would sink due to a decline of the allowed return on capital (*s*). This is not necessarily so in the multiple product case. (Knieps 2001, p. 87.)

The profit constraint of the monopoly is

(3.16) $$p(q)q(L,K) - wL - rK \leq (s-r)K,$$ that is

(3.17) $$\prod(L,K) \leq (s-r)K.$$

Therefore, if the allowed return on capital is known the profit depends only on invested capital, which can be seen directly from the profit function in equation (3.17). (Knieps 2001, p. 88.) This might lead to a so-called *Averch-Johnson-Effect*.

The Averch-Johnson-Effect (Berg and Tschirhart 1988, p. 324, Laffont and Tirole 1993, pp. 33-34) or "*gold plating of the rate base*" (Lewington and Weisheimer 1995, p. 280) is a special problem of the rate-of-return regulation. The allowed revenue depends only on capital and thus the firm has an incentive to make excessive investments into capital. It can be proven that under the rate-of-return regulation the relation of factor prices (e.g. capital in relation to work) is larger than the relation of respective marginal revenues is. Hence, the monopolist operates capital intensively in the cost of other production factors. In this case, the regulation practice itself causes distortions in the market. Therefore, the task of the regulator is not only to monitor the cost of the firm but also to observe the firm's efforts to try to decrease its cost, which is often difficult for an outsider.

There are further problems in the application of this method. The rate-of-return method requires an exact knowledge of the cost structure of the monopolist. However, the regulator only very seldom has all necessary information about the cost and the demand of the monopolist to be able to set the right price. Asymmetric information between the regulator and the regulated firm is one the most important causes for problems.

Another significant problem of the rate-of-return regulation is inefficiency. Since the utility gets its cost covered, the monopoly has only very little incentive to reduce its cost. The prices are adapted in short intervals to the actual average cost and so there is no need for the firm to lessen cost or to improve product quality. Therefore, unnecessary cost incurs and the "normal" technical development does not take place. This is not a sustainable policy in the long term.

Another issue arising with capital intensity is the evaluation of the capital stock. In general, the historic purchase cost of capital differs from the cumulated value of the depreciations. There are in general three possibilities to evaluate the capital base as already discussed in previous chapter:

- Evaluation at market prices. The problem with this method is that the value of the firm is often calculated as a sum of its future discounted profits. These depend on the prices, which will be set by the regulatory authority. Therefore, prices are set based on a circular argument.
- Evaluation at cost of recovery. This method can lead to problems in a situation with inflation.
- Evaluation at cost of purchase. This is the most used method in practice due to the problems of the other methods. (Wild 2001, p. 57.)

An additional problem of evaluation arises from the fact that the factors that influence monopolist's cost often cannot be defined accurately. What is the adequate security of supply, rational business management or the suitable length of the regulation period? These factors leave the monopolist a wide margin for manipulation.

To solve the problems of the rate-of-return regulation mechanism, Lewington and Weisheimer (1995, p. 281) discuss the following suggestions. The supply of information to the regulator should be improved. This would create more transparency in the cost and price calculations, however, no efficiency improvements. In the *moving goal posts* system or by changing some calculation basics the regulator continuously changes single conditions of regulation in order to avoid the Averch-Johnson-Effect. This suggestion does not seem very reasonable, since it makes a long term planning of the monopoly difficult and breaks the trust between the regulator and the monopolistic firm, which has a negative influence on the result of regulation. The third possibility is to discontinue regulation, which is not a very realistic option due to the market power of the national monopolist like already discussed.

3.5.3 Return-on-Cost Regulation

The *return-on-cost regulation* (also *cost-plus-* or *mark-up-regulation*) is based on the same principles as the rate-of-return regulation. The basis for regulation is the average cost, on which additional profit and risk supplements are added. The cost-plus rule is

$$(3.18) \qquad p(q)q = \sum_{i \in N} p^i(q)q_i \leq \overline{C}(q) = (1+m)C(q)\,,$$

where $p^i(q)$ is the inverse demand function of product i, $p = (p_1,...,p_n)$ is the price vector, $q = (q_1,...,q_n)$ is the output vector and $1+m > 1$, where $m > 0$ is the allowed mark-up. C is the minimum cost and $\overline{C}$ is the true cost, which could also be denoted as the allowable revenue. However, it is not necessary that the utility is producing at minimum cost. (Borrmann and Finsinger 1999, p. 356; Knieps 2001, p. 90.)

The difference to the rate-of-return regulation is that the additional supplement is defined based on the profit margin instead of capital stock. The problems remain the same. There is asymmetric information between the firm and the regulator. A special problem arises from the determination of the proper return. A problem similar to the Averch-Johnson -effect discussed above arises also with this method. Thus, to maximise its profit the firm has an incentive to extend the turnover.

The equation (3.18) can be rearranged so that we get

$$(3.19) \qquad \frac{m}{1+m} = \frac{p(q)q - C(q)}{p(q)q}\,,$$

where $\frac{m}{1+m}$ corresponds to the limit of the turnover like in the rate-of-return regulation. The firm aims at maximising profit. With strictly positive marginal cost, this raises the turnover over the level that would be profit maximising in the monopoly case without the regulation. In this case, the turnover maximum thus lies at the higher level of output than when maximising the profit. Hence, the firm will choose a higher level of output quantity than in case without the regulation. If the turnover maximum exceeds the cost by more than the allowed rate m, resources will be wasted. (Borrmann and Finsinger 1999, pp. 357-358; Knieps 2001, pp. 91-92.)

A difference between the two cost-based regulation methods is that the rate-of-return regulation influences the firms' choices between inputs whereas the return on cost regulation treats all inputs alike. Therefore, in the case of return-on-cost regulation there is no incentive to use some inputs inefficiently as it is the case with the rate-of-return regulation in respect of capital.

3.6 Incentive-Based Regulation Methods

The two biggest problems of the cost-based regulation methods are the cost that directly arises from the regulation practice and the firms' lack of incentive to improve efficiency. Incentive based regulation methods were developed to avoid these problems. The most important methods of the incentive-based regulation are the price-cap regulation and yardstick competition. They are both rather new ideas. Littlechild introduced the price-cap system in 1983 and a few years later Schleifer (1985) introduced his application of the yardstick model to regulation. The price cap method has been widely used in the regulatory practice already for several years often replacing the rate-of-return regulation, but the yardstick competition has not been winning popularity until the end of 90's.

3.6.1 Price-Cap Regulation

3.6.1.1 Main Principles

The principal idea, upon which the price-cap regulation is based, is that regulated firms are always better informed about their cost and the results of a specific regulatory scheme than the regulatory authority. Therefore, the aim of the price-cap regulation is not to set optimal prices based on full knowledge of cost and demand. Instead, the regulator's goal is to design such a scheme that will create an incentive for the firm to maximise the society's interests while pursuing its self-interest. (Acton and Vogelsang 1989, p. 369.)

This method is further based on the "*bounded-rationality hypothesis*" according to which in the absence of information about the cost and demand, regulation improves the situation of the customers only by making sure that their position will not be worse in the future periods (Knieps 2001, p. 107). The price-cap means that the regulator sets a ceiling for a price of all of the products or a basket of products. The utility is free to choose its price equal to or below the ceiling. The price is usually adjusted over the regulatory period in several years' intervals by comparing it with some general (often: price) index that is exogenous to the monopolist. The retail price index is most commonly used. (Acton and Vogelsang 1989, p. 370; Laffont and Tirole 1993, p. 17.)

By implementing price-cap regulation, the following issues should be considered. The composition of the basket of goods and services has an influence on the price cap regime. Another issue is to determine the height of the price cap and the frequency with which it is adjusted. The simplified formula $P = RPI - X$ can be interpreted as a price growth formula. RPI is the retail price index and X is an exogenously determined rate of technological progress. The subtraction of the productivity growth rate form the formula provokes a continuous real price cut.

The more formal presentation of the regulation method is simple. The prices $p_t = (p_{1t},...,p_{nt})$ are set under a constraint

$$(3.20) \qquad \sum_i w_{it}\left(p_{it} - p_{it-1}\right)/\, p_{it-1} \leq RPI - X \ ,$$

where t marks the period and i marks the product and w_i is the weight of the price of product i.

The equation (3.20) simply states that the weighted average of the relative price changes is not allowed to be larger than the general change in retail prices less a general productivity increase. If the weights are defined as a ratio of the value of the respective good or service then

$$(3.21) \qquad w_{it} = \frac{p_{it-1}q_{it-1}}{\sum_i p_{it-1}q_{it-1}}$$

where q_{it-1} is the quantity of the good i demanded in the period $t-1$. Then the equation (3.20) can be written as

$$(3.22) \qquad \sum_u q_{it-1} \frac{p_{it}}{\sum_i q_{it-1}p_{it-1}} \leq 1 + RPI - X \ .$$

In other words: to be able to adopt to changing environment or productivity changes the firm is allowed to choose the price structure within the basket (left side of the equation (3.20)), but it is not allowed to raise the average price of the basket by more than a fixed percentage per year. It can also be determined by the Laspeyres –price index (the left side of the equation (3.22)), which must be equal or smaller than one plus the retail price index less technology progress. (Laffont and Tirole 1993, p. 17; Pfaffenberger 1993, pp. 244-245.)

Although the price cap regulation is designed to avoid the problem of high information requirement, the process of setting the price, however, requires that the regulator is well informed about the technology, demand and cost conditions of the firm. If the price ceiling has been set too high, the firm will act as an unregulated monopolist. If the ceiling is too low, it threatens the survival of the firm. A similar method is a *revenue cap*-method, where the regulator fixes - instead of price - the allowed revenue of the utility.

Riechmann (1995, pp. 158-162) has discussed the incentive mechanisms in more detail. According to him, the incentive mechanisms are influenced by two other mechanisms: the *regulatory lag* and the *regulatory review*. He has defined regulatory lag as a systematic predictable reaction lag of the regulatory authority. It produces a stronger incentive to efficiency improvements i.e. to systematically decrease cost, because of the profits that can be yielded during the regulatory period can be retained over more periods. The regulatory review on the other hand, decreases this incentive the more the stricter the review is. For example, if the review is made based on the cost situation of the firm, then the previous cost cuts lead to a tighter price cap, so that the firm can set only lower prices than during the earlier periods.

Riechmann (1995) further discusses the problem of setting the appropriate length of the regulatory lag. It is widely recognised that longer lag-periods tend to cut costs. Generally, three to five years have been considered suitable. However, the consumers get the benefits from this cost decrease in a rather late point of time. The lag period can be longer if the demand elasticity of the regulated good or service is low. Respectively, the regulatory lag should be short if the effort to improve efficiency does not lead to significant cost reductions.

The intensity of the incentive mechanisms depends on the credibility and the predictability of the regulatory decision as well as on the reference standard for the price adjustment within the regulatory review. The regulatory decisions have a desirable effect only when they are credible and reliable. For example the X-factor should be high enough so that there will not be any possibilities for excessive profits, which would increase the public pressure against the regulatory authority to revise the price limit.

One important factor in the application of this method is to determine an appropriate X-factor. Bernstein and Sappington (1999, pp. 5-12) have provided a framework for this purpose. They define X-factor as the "rate at which inflation-adjusted output prices must fall under price-cap plans". According to them, the X factor is a sum of two factors, namely the difference of the growth rates of the total factor productivity in the regulated industry and of the rest of an economy as well as the difference of growth rates of output prices respectively.

One of the advantages of the price-cap model is that it allows the utility flexibility about its price structure. Further advantages are an increased cost cut and the avoidance of inefficient investments. However, there still is margin for misconduct since the monopolist might find it profitable to raise its costs just before the review and let them sink right afterwards. A disadvantage of the price-cap method can arise through a so-called *Ratchet effect*. This effect incurs when the firm is functioning very efficiently already in the first period. The regulator may then draw a conclusion that a more efficient situation is simple and easy to reach i.e. it requires a similar performance also in the next period and sets even stricter demands. Since the management of the company is aware of this problem, the company has an incentive not to improve its cost structure as much as it could so that it can maintain some scope of action. (Laffont and Tirole 1993, pp. 664-665; Riechmann 1995, p. 160.)

As a conclusion, a special feature of the price-cap regulation compared to other regulatory schemes is that the monopolist is allowed to keep any extra profit that it can capture by lowering its costs below the fixed price level. The price-cap model protects the consumers against monopoly. A successful price-cap-model can also help to promote competition by keeping the prices low, improve productive efficiency and innovation and reduce the administrative effort of regulation due to smaller informational requirement. In addition, it improves the expected profitability of the regulated firm because of improvements in efficiency.

3.6.1.2 Price-Cap versus Rate-of-Return Regulation

Laffont and Tirole (1993, pp. 17-19) discuss three principle differences of the price-cap and the rate-of-return regulation. First, although both of these methods fix the price for some period, the price-cap method is supposed to be prospective instead of retrospective. That is, in theory the future prices are not set based on the historic costs of the firm. In practice, however, the regulatory reviews have to be made based on some information and this is usually the firm's past performance. Second, the advantage of the rate-of-return regulation compared to price cap system is the guarantee that the firm gets a fair rate of return. Third, this means that the investment schedules are more protected than with the price cap method.

With the rate-of-return regulation, the utility has to justify its price setting by proving that it is consistent with the rate base. In price-cap regulation, the utility's price setting is limited to some maximum level but it is allowed to gain profit if the price is higher than its real costs. Therefore, another difference is that in the price-cap method the firm is allowed a downward flexibility in its price setting whereas with rate-of-return regulation the prices are fixed. In reality, this does not have much relevance for the utility's general price level but more for the structure of the relative prices within the product basket of the utility. It is recognised that in the end under price cap regulation the individual prices of the good in the basket reflect variable costs and demand elasticities more precisely than under the rate-of-return or other cost-based regulation methods. This is because utilities are able to optimise their prices within the product basket. (Baumol and Sidak 1995, p. 96.)

The length of the regulation periods is set exogenously in both of these methods. Under the price cap regime, the regulatory review is made in intervals of longer periods than with the rate-of-return regulation. In practice, the period is not always predetermined because of the pressure focused on the regulator from the public if the firm is getting large profits or is facing a loss.

Biglaiser and Riordan (2000, p. 745) have considered the dynamics of regulation in context of rate-of-return and price-cap regulation. The most important element in their model is the exogenous technical progress that lowers capital equipment and operating costs. In their model, the optimal price is formed from operating cost, the economic depreciation of capital and a part of fixed costs. The criticism they present against the rate-of-return regulation is focused on the static nature of this method. Rate-of-return regulation is designed not to adjust prices to the changing long-run marginal cost of a dynamic market structure but to recover historical investment cost. They argue that rate-of-return regulation leads to an economically inefficient level of capacity. Due to the weak incentives of this method, the old capital stock will not be removed and replaced with new capacity with lower operating costs.

Table 3.1: Comparison of rate-of-return and price-cap regulation.

Rate-of-Return Regulation	**Price-Cap Regulation**
- based on cost information	- based on information about revenue
- designed to recover historical investment cost	- designed to induce an incentive to improve efficiency
- regulatory period one year	- regulatory period 3-10 years
- price setting retrospective	- price setting prospective
- prices are rigid	- prices are rigid upwards
- extracts any extra profit	- allows the firm profit between the regulatory reviews
- administrative effort is high	- administrative effort is smaller

(Source: Own presentation.)

As a criticism against the price cap method, Biglaiser and Riordan argue that a temporary price-cap regime provides the firm distorted incentives for capacity replacement. In addition, when the price-cap time horizon is very short, the incentive scheme is weakened. It would then provide no better incentives for capital replacement than the rate-of-return regulation. Furthermore, they observe that repeated intervals of price-cap regulation can be expected to generate cycles in capacity replacement. A concluding comparison of the two regulation methods is presented in Table 3.1 above.

3.6.2 Yardstick Competition

Schleifer developed the basic idea of the *yardstick competition* (or *relative performance evaluation*) for regulation in 1985. According to his idea, the regulated price of a single utility should not be based on its own cost information but instead on the costs of identical firms. The regulator does not need any other information about the firm than the accounting data, not even about the cost or the cost reduction technology or effort. Schleifer thus proposes that the regulator compares similar firms with each other. This way the regulator can create a situation of competition in otherwise non-competitive markets. Hence, the yardstick competition is designed to reduce information asymmetries between the regulator and the regulated firm. The yardstick competition method creates a tool, a so-called *benchmark*, with which the regulator can evaluate the firm's potential based on comparisons with the other utilities in the market.

If the utility does not manage to reduce costs although others do, it loses, because it is set into a worse market situation when compared with the other firms. Respectively, the utility profits if it reduces costs when the others do not. An advantage of this model compared to the price-cap method is that there is no time lag in the extraction of monopoly rents. In addition, the market is no biased because of the regular regulatory review. The optimal policy for the firm is always to minimise costs. (Schleifer 1985, pp. 319-320.)

The incentive to minimise cost influences the utility's decisions permanently because the same mechanism works in the following periods. There is no reason for the regulator to change this method into any other regulatory regime, because the consumers receive the benefits from the cost minimisation at an early stage of time. Thus, there is no external pressure on the regulator to change the price regulation system. The yardstick model reduces prices in the short and medium term. (Burns et al. 1999, p. 286.)

The model of Schleifer (1985, p. 320) is based on the following assumptions: there is no uncertainty and all the firms face a downward-sloping demand curve in separate markets. Each firm has an initial constant marginal cost c_0. By spending $R(c)$, it can reduce the marginal cost to c. It is assumed that in the beginning situation the firm does not invest in cost reduction measures $(R(c_0) = 0)$ and $R'(c) < 0$ and $R''(c) > 0$. The first order derivation shows that higher investments in cost reduction lower final unit cost. Due to fixed cost reduction expenditures, the firm's average cost decreases.

The firm receives profits:

$$V = (p - c)q(p) + T - R(c), \tag{3.23}$$

where T is a lump-sum transfer to the firm from the regulator. The regulator is indifferent about the distribution of income between the firm and the consumers. Therefore, the lump-sum transfer does not affect welfare. The regulator maximises

$$Max W = \left\{\int_p^\infty q(x)dx\right\} + (p - c)q(p) - R(c), \tag{3.24}$$

subject to a break-even constraint $V \geq 0$ that specifies that the transfer covers losses. The integral in equation (3.24) is the consumers' surplus and the remainder of the equation presents producers surplus. (Schleifer 1985, pp. 320-321.)

In the social optimum, the transfer covers the expenditures on cost reduction and the marginal cost equals price. The condition for total cost minimisation to produce output q states that the marginal cost of cost reduction equals output in optimum. Schleifer further assumes that $-R'(c_0) < q(c_0)$, that $-R'(0) > q(0)$ and that $-q'(c) - R''(c) < 0$. These assumptions imply that cost reduction is cheap at the beginning but gets progressively costlier. When these assumptions hold, there exists a unique optimum. (Schleifer 1985, p. 321.)

The regulatory process begins when the regulator announces the pricing rule according to which the prices and transfers will be set based on observations. The regulator uses cost levels of identical firms to determine the appropriate price level. He has $N \geq 2$ firms under his supervision. He defines for each firm i

(3.25) $$\bar{c}_i = \frac{1}{N-1}\sum_{j \neq i} c_j$$

(3.26) $$\bar{R}_i = \frac{1}{N-1}\sum_{j \neq i} R(c_j)\,.$$

This means that each firm *i* is assigned its own 'shadow firm', with a cost level $\bar{c}_i$, which equals the mean marginal costs of all other firms and $\bar{R}_i$ equals the mean cost-reduction expenditure of all other firms. The shadow firm is the benchmark against which a single firm is compared. Therefore, if the regulator commits itself to $T_i = \bar{R}_i$ and $p_i = \bar{c}_i$ for each *i* and if the firm believes this commitment, the social optimum will be reached and the firm chooses its unit cost levels matching the conditions of social optimum. The yardstick method is effective and practicable because the firm cannot influence the price or the transfer payment through any inefficient choice. (Schleifer 1985, p. 322.)

Under the restriction that the regulator is not able to make any transfers (*T = 0*) the yardstick model should be based on the average cost of the utility thereby allowing higher prices, because the firm should be compensated for cost-reducing expenditures. This is actually the more common practice since the regulators are often reluctant to make transfers, because a transfer system increases administrative expenses. The following equations now characterise the social optimum:

(3.27) $$-R'(c_i) = q(p_i)$$

(3.28) $$(p_i - c_i)q(p_i) - R(c_i) = 0\,.$$

According to equation (3.27), the marginal cost of cost reduction is identical to the marginal gain of the producer's surplus. Equation (3.28) presents the breakeven condition. After solving the equation the regulator sets the price $p = \dfrac{R(c_i)}{q(p_i)} + c_i$ for the firm *i*. Firm *i* chooses c_i to minimise its total costs by deriving equation (3.28). The minimisation yields the first-order condition like in equation (3.27). In the average cost-pricing version of the yardstick model, all firms choose the second-best unit cost levels. (Schleifer 1985, p. 324.)

A general criticism of the yardstick model focuses on the assumption that all firms would be able to improve efficiency with the same rate. Even though it is possible, that efficiency improvements could lead to equal efficiency levels of the utilities in the medium- or long-term, it is more likely that in the short term firms will show much differentiated efficiency levels. The firms are likely to have different life cycles meaning that they might be in a different phase of their investment cycle or there might be differences in the economic cycle of the business area. Furthermore, the requirement that all firms were to improve efficiency with the same rate punishes those firms that are already functioning efficiently, because for them an additional efficiency improvement would be much more difficult to reach than for firms that function inefficiently. (Burns et al. 1999, p. 287.)

Schleifer (1985, p. 324) and Weyman-Jones (1995, p. 430) have discussed a case when firms are very heterogeneous. In such a case, the basic yardstick model would not lead to an optimal result because the comparison would be biased. The utilities might not be willing to accept the regulators decisions any longer if they were not corrected for heterogeneity. This problem can be avoided if the regulator can observe characteristics that make firms differ and corrects for heterogeneity. Schleifer calls this method *reduced-form* regulation. If the regulator is able to consider all relevant characteristics, this method can lead to a social optimum. If, however, some heterogeneity is not accounted for or is evaluated incorrectly, the optimum will not be reached.

Laffont and Tirole (1995, pp. 84-86) have focused to the influence of possible shocks to the heterogeneous firms. In this situation, the costs of the firms are stochastic. Laffont and Tirole distinguish a purely idiosyncratic shock, where the shock influences the cost of an individual firm, and an aggregate shock, where the costs of all of the utilities are affected. The yardstick model is very useful in a case of an aggregate shock, because it can filter the influence of the shock. However, in reality the idiosyncratic shocks dominate, which makes a direct comparison between the firms less useful.

Weyman-Jones (1995, p. 430) emphasises that the yardstick model is further based on three critical assumptions, namely: commitment, collusion and comparability. The regulator must *commit* itself to stick to the regulatory decision it made even if after the revelation of the firm's hidden information it would choose another regime. An important limitation of this model arises from possible *collusion* of the firms in order to manipulate the regulator. However, if the regulator is able to prove this kind of behaviour, it can punish the firms. Often these kinds of collusive strategies are not sustainable especially if there are a large number of firms. In order for the regulation to be successful, the regulator must have the authority to make the utilities accept the reward or penalty decisions of the yardstick competition. The only rules that the companies will accept are such that treat them equally. Therefore, the regulator should design the regulatory regime so that companies' differing structural characteristics will be taken into consideration so that they can be compared on equal terms (*comparability*).

Tangerås (2002, pp. 231-233) has studied the incentives of firms to collude. He has developed an optimal yardstick competition model under the threat of collusion and symmetric information. The main purpose of yardstick competition is to improve efficiency. Thus, collusion would mean that the utilities make collective decisions about the level of efficiency that each utility should maintain by understating the industry specific productivity. The analysis shows that, in such case, the regulator has to reward (punish) a firm for not colluding (for colluding) by setting up a system of transfers that is based on the differences between the firms' reported productivity and the industry average. Thus, in the presence of this reward system collusion would be sustainable and profitable only in a case when the firms can commit themselves to side-payments. If this is not possible, the reward system induces that each firm deviates from the agreement of understating productivity. Firms thus report correctly their productivity, which reveals the industry productivity truthfully, and so no rewards need to be paid. Hence, collusion can be avoided without any social cost in equilibrium. If, however, there is a possibility to unlimited inter-firm payments collusion creates a trade-off between efficiency and rent-extraction. In this case, the efficiency of low productivity companies remains under an optimal level and the efficiency of high productivity companies above it.

The yardstick competition is not very widespread in the practical implementation of regulation in spite of the promising theoretical considerations. The explanation might be that the implementation of this method is unprofitable if it is very expensive compared with a system of individual regulation for example due to high requirements on acquisition of information from all utilities.

3.6.3 Other Incentive Based Regulation Methods

Three other methods to incentive regulation will be presented shortly in this chapter. Sibley (1989) has called them anonymous mechanisms. The principal idea of these methods is based on small informational requirement of the regulator. Firms reveal their private information through incentive mechanisms built in the regulatory scheme and eventually these methods lead to marginal cost pricing. These methods are based on subsidies, which is one of the reasons why they are not applied in practice.

3.6.3.1 Vogelsang and Finsinger – Method

Vogelsang and Finsinger (1979) have developed a model (VF-method) for optimal pricing of a multi-product firm based on a minimum information requirement. The basic principle of this model is that the regulatory authority sets incentives to make the firm lower its prices successively until a Ramsey price structure is reached. The information the regulator receives from the bookkeeping of the firm is assumed sufficient. Therefore, the regulator needs to observe only the total cost $C(q_t)$, output q_t and unit profit π_t of the last period t and prices p of the present period. The regulator sets a constraint $q_t\pi - C(q_t) \leq 0$ i.e. the revenue should equal or be smaller than cost. The firm chooses π to maximise its profit. In the next period, the regulator will again set the constraint based on the information from the previous period. Thus, the regulatory constraint bases on the idea that the firm can choose any desired price vector in this period as long as it does not allow any profit measured with the amounts sold in the previous period i.e. it does not exceed the total cost of the previous period. (Borrmann and Finsinger 1999, p. 373; Knieps 2001, pp. 92-93; Pfaffenberger 1993, pp. 247-250.)

Welfare is defined as the consumer surplus that is defined by an equation

$$\sum_i \int_{\pi_i}^{\infty} d_{it}(p_i)dp_i, \tag{3.29}$$

where $d_{it}(p)$ is the demand of the good i with a price vector p_i.

The price settlement constraint, under which the firm is set is:

$$\sum_{i=1}^{n} p_{i,t}q_{i,t-1} \leq C(q_{t-1}). \tag{3.30}$$

q is the quantity and C the cost. Thus, welfare will be maximised through an iterative process, in which the welfare increases at each step with the amount of the profit from the previous period. Hence, this method is a dynamic mechanism: the price will converge into an optimum, where demand equals average cost and the price is a Ramsey price. This method only functions in a stationary environment when the firm has a price that allows it to have non-negative profits in each period. The method therefore limits the firm's possibility to influence the price i.e. to set it too high, but it still allows some freedom so that the firm can maximise its profits through the price structure. (Pfaffenberger 1993, pp. 247-250.)

There are however various problems in the practical implementation of this model. There is no intertemporal connection between the cost functions of different periods. The long run investment cost, however, plays a significant role in the electric industry but the method only considers the cost at that specific period. This slowly towards the maximum converging method also unrealistically assumes that the cost and the demand functions stay stable in time and does not consider the changes in these functions for instance due to technical change. A very serious problem is the incentive of the firm to deceit the regulatory authority by publishing its cost. Therefore, the VF-method can only function if it is combined with cost examination. (Borrmann and Finsinger 1999, pp. 377-378.)

3.6.3.2 Incremental Surplus Subsidy Scheme ISS

Sappington and Sibley (1988) have discussed a model of *incremental surplus subsidy scheme (ISS-scheme)*, which is based on a similar idea as the VF-method discussed above. The both methods are schemes designed to induce high incentives for the regulated firm to reveal its demand and true cost.

The ISS scheme is implemented in a situation without any uncertainty. It assumes that the regulator does not have any information about the utility's cost structure. The model begins in a stationary environment with a single product and known demand. The assets of the firm are assumed to last for only one period. Sappington and Sibley (1988, p. 297) list the characteristics of this scheme:

- It induces the firm to set the price equal to marginal cost in every period
- It induces the firm to minimise its production cost every period
- It eliminates all monopoly rents of the firm in every period after the first one.

The basic idea of the ISS system is to grant the utility an increment of the total surplus that it gathers during all periods of action. This increment is given at the first period, after that the consumers receive the whole surplus because the utility applies marginal cost pricing after the first period. Sappington and Sibley (1988, p. 297) argue that this first period of sharing is sufficient to give the utility an incentive to act in such a manner that it maximises social welfare permanently right from the beginning. In this scheme, the regulator knows as much as the monopolist about the demand function as well as the discount rate.

The principle of the model is that the regulator observes firms prices and total expenditures with a lag of one period. The total expenditures include extra expenditures that the firm might make in order to misguide the regulator. The firm is allowed to set any price it desires and it receives the revenues from its production in each period. In addition, it is awarded a subsidy in period *t*, which is the difference of the utility's revenue and expenditures in period *t-1* subtracted from an increment of a consumer surplus generated by the price change between periods *t* and *t-1*. The subsidy is not necessarily positive.

The utility maximises its revenue each period in a situation with an infinite amount of periods. The revenue consists of profit and subsidy less cost and extra expenditure. Sappington and Sibley (1988, pp. 300-301) prove that the utility operates at the minimum cost every period, that the utility receives positive profits only in the first period and that the utility set the price equal to marginal cost every period.

Sappington and Sibley (1988, p. 298) criticise the VF-model because the convergence of the price to marginal cost may take several periods. The ISS-model differs from the VF-model in that respect that it enables the regulator to induce an immediate movement to marginal cost pricing because in the ISS-model it is assumed that the regulator possesses the same demand information as the monopolist. Furthermore, the VF-model works only in the stationary environment. This assumption is not necessary in the ISS-model, in which the utility continues to set marginal cost prices even when the environment is not stationary.

The most essential difference between the VF-model and the ISS-scheme is that the marginal cost will be reached at the first period under the ISS scheme but not under the VF-model. Thus, the firms profit in the first period under the ISS scheme equals to the increment in total surplus, which is the consumer's surplus plus profits. This is generated by the move to marginal cost pricing. Sappington and Sibley (1988, p. 302) also prove that consumer welfare is non-decreasing over time, because the payoff internalises the regulator's goal of surplus maximisation.

3.6.3.3 The ISS-R Scheme

The ISS-R system builds on the ISS scheme and is developed by Sibley (1989) to help setting a price limit in the price-cap regulation. In this model, the regulator does not need to have any information about the utility's technology or even about the market demand, which is an improvement compared to the basic ISS-model. The regulator is assumed able to observe accounting profits, prices and outputs. The environment is supposed to be stationary. Sibley suggests that two-part tariffs (see chapter 0) should be allowed in the price-cap model (chapter 3.6.1). In this scheme, the firm minimises its cost and sets the price of the usage charge to equal marginal cost.

In the ISS-R model, the regulator observes the utility's profits from sales continuously and uses the profits and the prices from the last period to design a two-part tariff, which the utility has to offer to customers along with its own proposal for a tariff. The utility sets a tariff based on private information about demand. When the customers choose between these tariffs, the real demand will be revealed. If the demand is truthfully revealed, the utility's profit maximising problem will be the same as with the ISS-model. The advantage of these models compared to most methods is that they do not require a commitment from the regulators part to keep the scheme after the monopolist reveals its private information.

Sibley (1989, p. 403) lists factors that limit the direct applicability of the model. First, it has been assumed that the consumers are completely rational, which is most likely not to be the case especially not for the residential users. Second, the analysis does not adequately take into consideration the information asymmetries between consumers and the monopoly. Third, the model works in a stationary environment and therefore the effects of non-stationarity are not considered sufficiently thoroughly.

3.7 Concluding Remarks to Regulation

Good regulation should provide incentives for short and long-term efficiency. The newest insight has been that allowing companies to retain a share of the gains from cost reduction encourages efficiency. To support long-term development and efficient investments, the regulation should be stable and the regulator committed to the chosen method. A regulatory scheme that is open, transparent, consistent and accountable supports the favourable development of the market. The investments to the network support competition in the downstream competitive market. Therefore, it is important to consider regulation also from the point of view of creating an incentive to the firms to develop the network and support investments to the network capacity.

The main problem of the theoretical regulation methods is the asymmetric information between the regulator and the regulated utility. The regulator always has incomplete information about the true cost of the firm. It is also difficult to associate the non-product specific cost with the right cost carriers, which poses an additional information problem of cost-based regulation. Another significant problem is inefficiency. Different regulation methods can therefore be classified based on their approach to efficiency improvements and informational requirement.

Regulation based on marginal cost fails because this method does not consider fixed cost that is very high in the electricity distribution industry. The average cost pricing principle fails because of the cost division problem. Ramsey prices and two-part tariffs are not acceptable because they discriminate between customers. In addition, they do not produce a reliable regulation result because of asymmetric information. The rate-of-return regulation yields the same problem and further does not produce a socially efficient solution because the efficiency improvement is missing. With the price cap method, the regulator tries to solve the problems mentioned above by setting an upper limit to the price according to the cost of the utility with a longer regulatory period. During this period, the firm is allowed to keep all profit that it can extract through cost reductions. The problem is that the firm might have the incentive to increase its cost again for the time of the new review in order to prevent the sinking of the price cap. In this case, the efficiency improvement between regulatory reviews will not benefit the customers at all.

The yardstick competition avoids this problem of asymmetric information through a benchmark. The regulator compares all the firms in the sector and determines, based on this information, what kind of performance the utility should produce. It will be determined whether the prices are reasonable based on a comparison between all utilities in the sector. This method creates an incentive to cost reductions and efficiency improvements because the firm gains when it improves its performance (i.e. decreases its cost) and the other firms in the markets do not. Respectively it loses when the other utilities reduce their cost and it does not. Problems can arise if firms are very heterogeneous and therefore there is no realistic comparison for the regulated companies. Theoretically, companies could form a collusion, which would falsify the result of regulation. The application of the yardstick competition becomes more difficult if many firms in the sector merge, because then there might be no suitable shadow firm (benchmark) for the utilities.

Other methods that are represented here are based on state subvention that has to be financed through higher taxation that causes efficiency losses in the economy. That is why these methods are not practicable in the real world regulation.

In practice, creating competition without cost is impossible. All the normative theories face limits in their practical implementation. There is no “right model” and that is why the models must be modified to the real-life situation. The positive theories of regulation consider the interest of various interest groups and try to determine a pareto-optimum through more practical considerations. The next chapters present practical regulatory schemes applied in the regulation of the electricity distribution networks in the Nordic countries.

Part II: Empirical Evidence

4 STRUCTURE OF THE ELECTRICITY SECTORS IN THE NORDIC COUNTRIES

4.1 Introduction

The last two chapters focused on theoretical considerations about natural monopolies and their regulation. This chapter concentrates on the empirical experiences of regulation and the characteristics of the electricity markets in the Nordic countries. The first part of this chapter discusses the structure of electricity production and consumption. In the second part, the distribution and transmission infrastructures are described in more detail. The last part considers the regulatory schemes and the electricity market legislation in these countries.

The Nordic countries have taken a leading role in the liberalisation of the electricity markets in Europe. In Norway, the liberalisation of the electricity sector began already in 1991 and the full market access for all end-user groups was established in 1995. Encouraged by the good experiences of Norway, Sweden and Finland liberalised their electricity sectors in 1996 and 1997, respectively. In Sweden, the liberalisation has lead to significant changes in the structure of ownership of the branch into more concentration and international ownership (see Figure 4.1 below). Denmark began with the gradual liberalisation in 1999. The market was fully opened 1.1.2003. (Electricity Supply Act 2001, § 7; Jonassen 1998, p. 3; SNEA 2000, pp. 2-4.)

The transmission and distribution tariffs and other terms of business operations are set under supervision in all of the Nordic countries. The systems are based on a so-called *regulated third party access*, which means that the networks are open to parties other than the owners of wires i.e. the generators must be guaranteed an access to the network and the customers may freely choose from whom they want to buy their electricity. An alternative system is *negotiated network access* that is based on mutual agreements between two actors without a specific regulatory institution, as in the case of Germany.

The structure of electricity production as well as electricity consumption per capita show differences between these countries. Historical and geographical factors explain some of the differences in electricity production and consumption. For example, due to the favourable geographical location and the topography of Norway, the very high amount of electricity it produces by hydropower is exceptional in the world. Varying amounts of energy intensive industry and electric heating systems explain a large part of the differences in consumption of electric power in these countries.

Further, the density of population differs in these countries. For example, Denmark[1] is approximately six times more densely populated than the other continental Nordic countries. The population density naturally influences other factors like the amount of cables per capita or per area. In Norway and Sweden, the main power flow is from northern production to southern consumption. Electricity demand is growing in all of these countries, which means that there is a need to improve and strengthen electricity transmission and distribution capacity. The trend is towards mergers of companies and development of larger generation companies.

[1] Greenland and the Faeroe Islands are not been taken into account when considering Denmark.

4.2 Structure of Electricity Production and Consumption

In 2000, the total production of electricity in the Nordic Countries was 386.1 TWh, of which more than a half was produced by hydro power in Norway, Sweden and in Finland. Indeed, the special characteristic of the electricity generation in these countries is their high dependency on the annual rainfall. The nuclear plants in Sweden and in Finland produced 25 percent of the electricity and the combined and other thermal power plants in Finland, Sweden and Denmark produced circa 17 percent of the total amount of electricity. The rest was produced by renewables and waste. (SNEA 2001a, pp. 5-6.) Figure 4.1 below shows the structure of electricity production by fuel in 1999. It is obvious that there are significant differences in the electricity production structure between these countries.

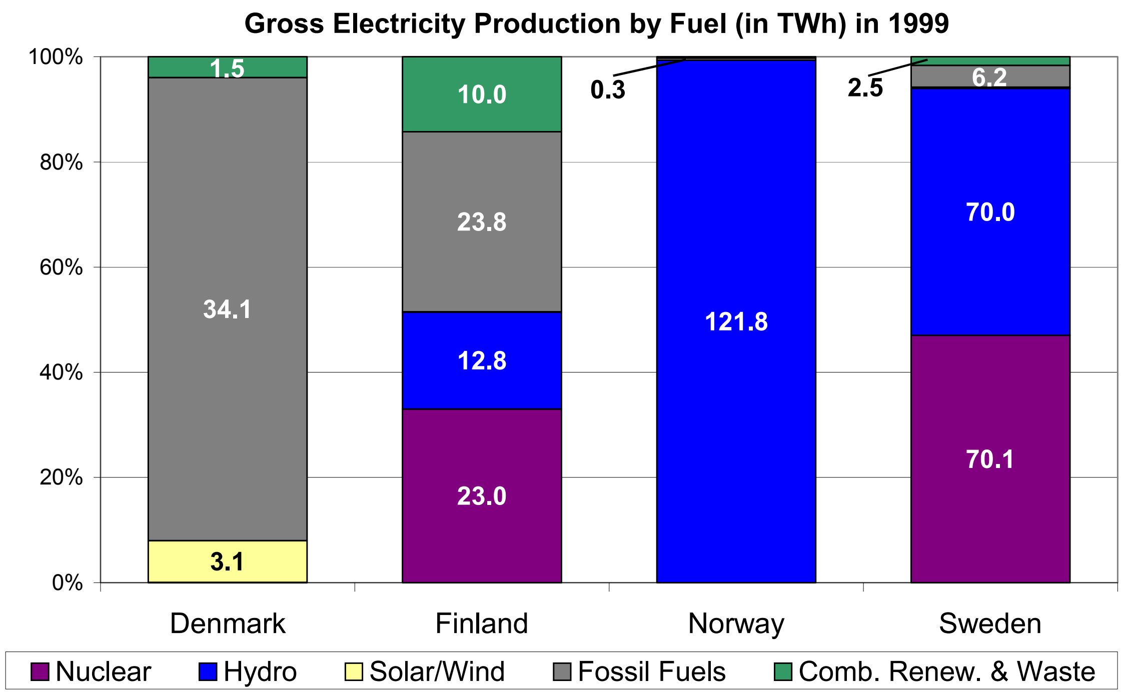

Figure 4.1: Gross electricity production by fuel (in TWh) in 1999.
(Source: IEA 2000, table 3.)

Denmark is the country that is most dependent on fossil fuels. Fossil fuels accounted for roughly 88 percent of the Danish electricity production in 1999. Coal and natural gas firing in combined heat and power stations are the predominant forms of electricity generation. (SNEA 2000, p. 6.) Denmark has built a lot of wind power and in 1999 the share of wind power of the total electricity production was already eight percent, which is a leading share world-wide. (IEA 2000, table 3.) It has the highest wind power capacity also when measured per capita, per area or per GDP. Another characteristic of the system in Denmark is that it relies by large on combined heat and power production. Thermal plants producing only electricity are not authorised and nuclear power is not allowed at all. (European Commission, 2000.)

In Finland, there are about 400 power plants. Half of them are hydropower plants although in 1999 only 18 percent of the Finnish electricity was produced by hydropower. Fossil fuels and nuclear power each accounted for about one third of the Finnish electricity production, 33 and

34 percent respectively. Combined renewables and waste formed 14 percent of the electricity production. (IEA 2000, table 3.) In 2000, approximately half of the produced electricity was consumed by industry and one quarter by residential consumers. (EMA 2001b, p. 4.)

Norway produced almost 100 percent of its electricity with hydropower in 1999. A small fraction was produced by fossil fuels, renewables and waste. (IEA 2000, table 3.) Obviously, Norway is highly dependent on the amount of annual rainfall. Naturally, this causes large changes in the electricity production structure between years and therefore during a dry year Norway has to import electricity. According to SNEA (2000, p. 7) the capacity of electricity generation is going to rise from 122 TWh in 1999 to 133 TWh by the year 2010. This rise is expected to consist mainly of gas-fired power. Typical for the electricity system in Norway is that there are many electricity supplying companies. There are approximately 60 companies that produce electricity and over 200 companies working with the sales and transport of electricity. The suppliers of electricity are mostly owned by the state. (Perner & Riechmann. 1997, pp. 237-238.)

In Sweden, hydro and nuclear power accounted for about 94 percent of the electricity production in 1999. They both made up for approximately 47 percent of the electricity production. The share of fossil fuels is only about four percent. Renewable energies and waste account for the rest. Because of its high dependency of hydropower, also Sweden has to import electricity during a dry year. (IEA 2000, table 3.)

The largest companies in the Nordic electricity sector in 2000 were Vattenfall, Fortum, Statkraft and Sydkraft. In 2000, the six largest companies in the Nordic markets together produced 59 percent of the total energy generated in the Nordic markets. Norway and Sweden both produced 37 percent of the total generated electricity; Finland produced 17 percent and Denmark 9 percent. Table 4.1 lists the largest companies and the amount of electricity generated by them. It can be directly seen from the table that the markets in Denmark, Finland and Sweden are rather concentrated meaning that the companies have horizontal market power, which poses a threat to the functioning of competition in the market. The largest company was Vattenfall, whose share was almost one fifth of the Nordic generated electricity and a half of the electricity generated in Sweden in 2000. In Finland, Fortum had even a larger share: 61 percent of the generated electricity.

Table 4.1: Largest electricity generators (in TWh) in 2000.

Generators	Electricity Generated in 2000, TWh	Proportion in the Country, %	Proportion in Nordic Countries, %
Elsam	12,5	37	3
EK Energy AB	12,1	35	3
Total for Denmark	**34,2**	**100**	**9**
Fortum	40,7	61	11
Pohjolan Voima Oy	15,1	22	4
Total for Finland	**67,2**	**100**	**17**
Statkraft	40,2	28	10
Norsk Hydro	11,5	8	3
Total for Norway	**142,8**	**100**	**37**
Vattenfall	69,3	49	18
Sydkraft	27,2	19	7
Total for Sweden	**141,9**	**100**	**37**
Total for largest Nordic electricity generators	228,6	-	59
Total for the Nordic Countries	**386,1**	**-**	**100**

(Based on: SNEA 2001a, p. 34.)

According to Swedish National Energy Administration (SNEA 2000, p. 8), electricity consumption in the Nordic countries has increased at an annual average of 1.2 percent since 1990. The increase was highest at the residential and service sectors, which is due to growing service sector and to an increasing number of electrical equipments used in households. There are seasonal changes in the electricity consumption and generation especially due to the geographical location in the north where the cold winters increase electricity consumption.

Figure 4.2 below shows the electricity consumption per sector in 1998. The figures show that the industrial sector consumes the most electricity in all countries except in Denmark, where the residential sector is already a slightly larger consumer of electricity. Apart from that, the electricity consumption structure in these countries is rather similar. A statistic of the IEA (2000, table 15) shows that in the industrial sector the paper and pulp industry are by far the largest electricity consumers in Finland and in Sweden. Norway has a lot of metal industry, especially aluminium industry. In Denmark, the largest electricity consumer in the industrial sector is food and tobacco followed by machinery.

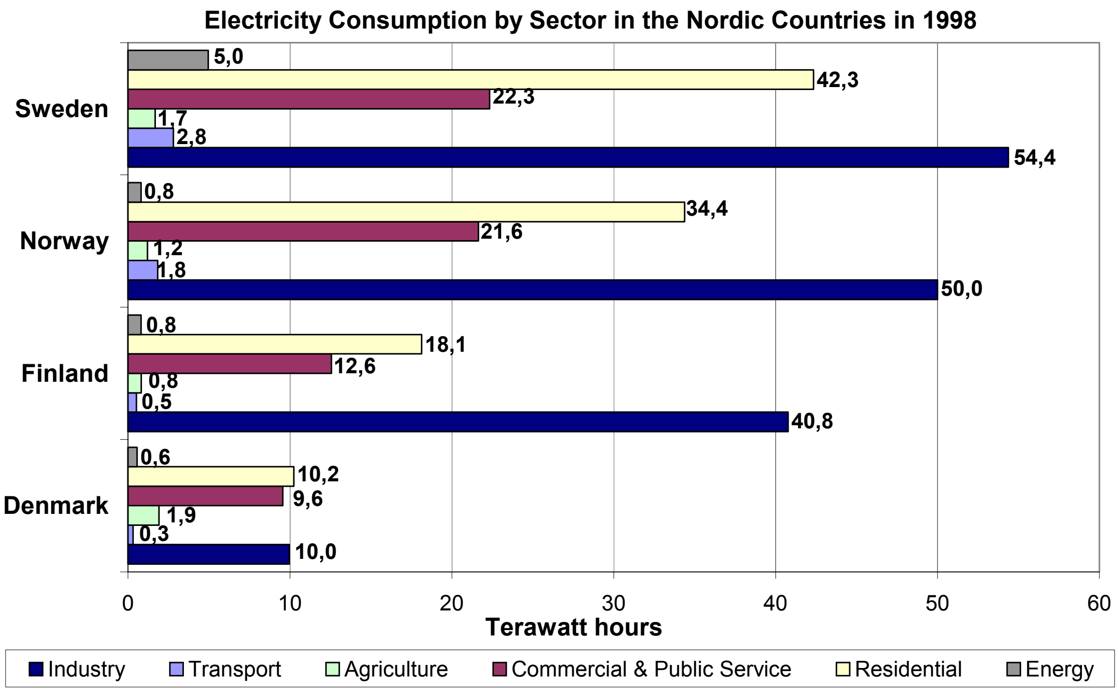

Figure 4.2: Electricity consumption by sector in the Nordic countries in 1998.
(Source: IEA 2000, table 14.)

In all of the Nordic countries, electricity consumption is expected to rise. SNEA (2000, pp. 8-9) forecasts that the energy consumption in Denmark will rise by circa four percent, in Finland by 18 percent and in Norway by 12 percent between 1999 and 2010

4.3 Distribution and Transmission of Electricity

4.3.1 Overview of the Nordic Countries

In the Nordic countries, the network of power lines is composed of three vertical levels: the national grid, regional networks and local networks. In all of the Nordic countries, transmission system operators are responsible for the *national grid* composed of 110-400 kV lines as well as for the links with the neighbouring countries. Large power stations are connected directly to the national grid and are allowed to use the grid to transmit electricity. In addition, companies that are active in foreign trade or are balance providers can use the national grid. (SNEA 2001a, p. 28.) If the cross border Nordic trade of electricity intensifies as expected, the transmission capacity of trans-border lines might form a bottleneck, especially between Norway and Sweden as well as between this Norwegian-Swedish system and Finland.

The *regional networks* usually operate at 70-130 kV levels (in certain cases even 220 kV). The regional network utilities transmit electricity from the national grid to local networks and in some cases also directly to large electricity users. From the local networks, which normally operate at 20 kV levels at maximum, electricity is transformed in the distribution areas to the normal domestic voltage of 380/220 volt. Figure 4.3 presents as an example a typical structure of the electricity network in Norway. Here, the vertical structure of the industry can be seen divided by the voltage levels. (SNEA 2001a, p. 28.)

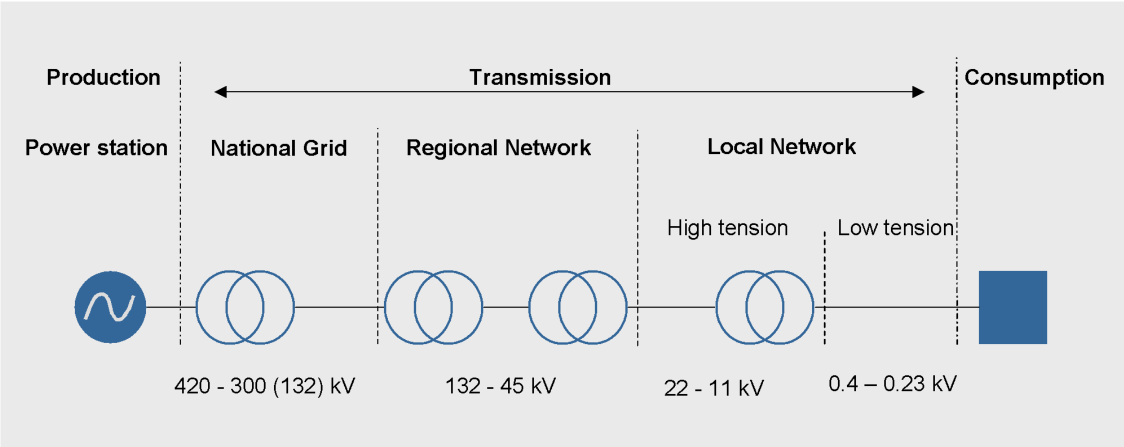

Figure 4.3: Power system.
(Source: NVE 2001.)

Table 4.2 below lists some key numbers of the electricity transport system in the Nordic countries. As can be seen from the figure, Sweden had almost twice as many customers in the low-tension network than the other countries in 1999. In addition, the capacity requirement of the Swedish network is the highest based on the peak load of the high voltage network. Sweden and Norway have the highest number of network utilities. Denmark and Norway have the lowest rates of cables per unit of peak load in the high-tension network. Measured by consumption per cables in the high-tension network they also have the leading position. These two indicators suggest that the capacity of the high-tension network cables is better utilised in these two countries or the capacity is more congested.

Table 4.2: Some general indicators of the electricity sector in the Nordic countries.

	Denmark	Finland	Norway	Sweden
Indicators of the Total System (2000)				
Electricity consumption per capita [(kWh/a)/capita]	6559,4	15323,8	27888,1	16525,5
Density of population (persons/area^2)	123,5	15,3	13,7	19,7
Peak loads in high voltage network (MW)	6284	12700	20420	26000
Indicators of the High Tension Network (2000)				
Cables per capita (km)	1093	4164	4110	3457
Cables per area (km)	0,14	0,06	0,06	0,07
Cables per unit of peak load (km)	0,93	1,69	0,89	1,18
Consumption per cables (GWh/km)	6,00	3,68	6,79	4,78
Indicators of the Low Tension Network (1999)				
Number of Customers (Million)	2,9	2,9	2,5	5,2
Number of Network Utilities	80	100	200	208

(Based on: Nordel 2001; Weltjahrbuch 2000; SNEA 2001a, p. 26.)

Denmark's structure differs from the structure of the other Nordic countries because it is lot more densely populated. It also has a special geographical structure since the country is formed from a large peninsula and four main islands. The electricity consumption per capita is significantly lower in Denmark compared with the other Nordic countries. There are a lot fewer cables per capita in Denmark although more cables per area due to population structure.

4.3.2 Denmark

The special characteristic of the Danish transmission network is that there are two independent transmission system operators, who are responsible for the security of supply in their service area. One grid transmits electricity in the western part of the country (Jutland and Funen). It is operated by *Eltra* that owns and operates the 400 kV and 150 kV networks as well as the connections to neighbouring countries. The firm has divided production, transmission and distribution into independent legal entities. 47 local distributors in the network area own it. (Eltra 2001.) This western network is linked to UCPTE[2] net. *Elkraft System* operates the eastern part of the country's network. It is linked to the Nordel net. Elkraft's grid is formed from 132 kV and 400 kV lines. (Elkraft 2001.) The two transmission line systems are not interconnected with each other.

Denmark produces a relatively large share of its electricity with wind power. This sets special requirements on the capacity and security of the network. Due to the large unregulated production, it is often necessary to transport large amounts of energy over long distances.

[2] UCPTE = the Union for the Coordination of Production and Transmission of Electricity.

There are approximately 80 network utilities active in the distribution network in Denmark (SNEA 2001a, p. 26.) The low-tension network in Denmark is composed of cables into much higher degree than the low-tension networks in the other Nordic countries. In 2001, the 0.4 kV network had 81 percent and in 6-20 kV network 76 percent cables of total lines. The amount of overhead lines is steadily declining whereas the amount of cables is rising. (Dansk Energi 2002a, p. 59; Dansk Energi 2002c.)

4.3.3 Finland

The Finnish national grid is composed of ring formed connections where the used lines are of 440, 220 and 110 kV. There are approximately 14 000 km lines and 100 power stations. *Fingrid Inc.*, who owns and operates the national grid, is responsible for the transmission of electricity and bears the system responsibility. The task of balance provision is shared with 20 additional balance providers that are usually large generators. Fingrid is partly owned by the state, power producers and other institutional investors, none of which has a dominant position in the company. Fingrid transmits yearly about fifty terawatt hours of electricity through its transmission lines, which amounts to two thirds of the total electricity consumed in the country. (Fingrid 2002; SNEA 2001a, p. 29.)

Ten regional distributors operate and own the regional distribution networks. Regional networks are defined as networks with 110 kV lines and stations that do not belong to the national grid. The local distribution networks possess lines with tension lower than 110 kV. There are 230 000 km 0.4 kV lines, of which 60 000 km are cables and 170 000 km overhead lines. At the beginning of 2001, there were about 100 local distribution network holders. The amount of utilities reduces yearly. (EMA 2001b, p. 28.)

4.3.4 Norway

In Norway, the national network is owned and organised by Statnett SF that is owned by the Norwegian state and is responsible for the system operations as well as for the development of the national grid. In 2000, Statnett owned some 84 percent of the main grid because approximately 40 other companies own small parts of the national grid. These parts of the grid are leased by Statnett SF. Statnett, with some other participants, is responsible for the balance in the network. These other balance providers can be power sellers, network owners or large end-customers. Network owners with balance responsibility are entities that buy network losses directly on the wholesale market. The other network owners must meter and report the distributed electricity to the balance providers. (Grasto 1997, p. 3; Jonassen 1998, pp. 14-15; Statnett 2001, pp. 7-12.)

At the beginning of 2001, the national grid was compounded of almost 90 power stations and of 10 000 km lines that are mainly of a higher voltage than 200 kV. In Norway, the main power flows take place from the northern production facilities to the south, which might cause congestion in the transmission capacity. A high amount of cross-border transmission between southern Norway and Sweden takes place and thus there is much congestion between the countries. Therefore, there are plans to increase transmission capacity from 3000 MW to 4000 MW by 2003. (SNEA 2001a, p. 29; Statnett 2001, pp. 7-12.)

There are about 150 local distributing network companies and circa 60 regional transmission companies. The regional companies are often vertically integrated and they distribute electricity also at the local level. They are formed from power lines that usually have a voltage of 132 kV and 66 kV. The regional network utilities are organised in different tariff zones. Local or regional authorities often own the regional network utilities. (Grasto 1997, p. 3; Statnett 2001, p. 7, 44.) The distribution utilities are among the smallest in Europe and the structure of ownership is very homogenous although the operation environment is very heterogeneous (Agrell and Bogetoft 2003, p. 58). The local distribution utilities as a rule belong to the local municipalities and a majority of them operate in sales of electricity. Thus, the liberalisation in Norway has not led to privatisation of the electric utilities, but the trend is that large generation companies merge and buy local distribution utilities. In Norway, the markets provide the electricity needed to balance the load in the network.

4.3.5 Sweden

Sweden has approximately 15 200 km of 220 kV and 400 kV transmission lines. The national grid company *Svenska Kraftnät* is responsible for the operation of the national grid. At the end of 2000, about 28 companies were connected directly to the national grid. One third of them were regional networks and the rest were power station owners. (Unipede 1998, p. 37.) Svenska Kraftnät has also the system responsibility, which entails managing the network operations and expansions. It co-operates with balance-responsible companies by voluntary agreements in order to maintain balance on a momentary basis. Every injection point and every output point must have an appointed company that is responsible of balance in each point (point balance). (SNEA 2001a, p. 28; Unipede 1998, p. 37.)

Characteristic for the Swedish system is that the national grid has capacity bottlenecks between the north and the south: To reduce the physical electricity flow in the grid, Svenska Kraftnät buys electricity in areas with surplus and sells a corresponding amount in areas with shortfall (*counter-purchase*) without affecting the trade of customers. Due to bottlenecks, different price-areas occur in electricity transmission. (SNEA 2001a, p. 29.)

The regional networks operate in the voltage level of 130-40 kV and the local networks operate at less than 40 kV level. There are 9 regional network owners and about 250 network utilities in the local network. The network owners must have a concession to be allowed to operate in the markets. (Svenska Kraftnät 2001, pp. 5-10.)

4.4 Regulation of Electricity Distribution and Transmission

In all of the Nordic countries, the market opening is based on a regulated third-party access. Thus, the network utilities are monitored or regulated by an authorised institution that is responsible for setting rules and monitoring the electricity sector. In Norway, this party is a *ministerial agency*. In other countries, there are *independent regulatory authorities* that share regulatory responsibilities in the markets with the ministries. Electricity production in all of these countries is subject to an authorisation. (IEA 2001, p. 33.)

The driving force behind the new energy market legislation has been the need for cost savings and a more efficient use of energy resources. The legislation in all of these countries requires a separation of accounts of network operations and other business activities. In Sweden, it is even required that the activities are separated into independent companies. This unbundling is required in order to avoid cross subsidisation of the competitive part of the electricity sector through the network operations and to increase transparency in the network operations. The new directive of the European Commission requires the total separation of utilities into legal entities (see chapter 2.2.7 above) and therefore Denmark and Finland are required to unbundle their distribution utilities from production and sales. In the long term, it is required that distribution and transmission are also separated, which, however, does not affect the Nordic countries because there these business fields already are separated.

The Finnish, Norwegian and Swedish markets - and lately to an increasing amount also the Danish - are very much integrated through the Scandinavian transmission network organisation, NORDEL and the Nordic Power Exchange, the Nordpool. Therefore, the national grids as well as the regulatory authorities need to co-operate more closely also across the border.

4.4.1 Regulatory Framework in Denmark

4.4.1.1 Institutional Players and Electricity Supply Act

Three institutions regulate the electricity sector. The Danish Energy Agency is an agency of the *Ministry for Environment and Energy* that is responsible for the general energy policy. The *Energitilsynet* (Energy Supervisory Board) is the main authority that is responsible for the supervision of end user prices and delivery conditions as well as for the tariff setting of the transmission of electricity. The board is appointed for four years and has the authority to request information from the electric utilities as well as sanction them in case of failure to follow the set rules. The third party active in the Danish market is *Konkurrencestyrelsen* (the Danish Competition Authority). (Energy Supply Act 2001, § 78-82; IEA 2001, pp. 53-55.)

Market opening in Denmark started January the 1st 1998 when the largest consumers were allowed to access the market. The opening took place gradually and the markets are fully opened from January the 1st 2003. In Denmark, the electricity market is regulated through the *Electricity Supply Act* (ESA) no. 375 of June the 2nd 1999. The law has been amended several times afterwards. Here referred are the amendments of August the 28th 2001. The act leaves the Ministry a lot of freedom to set further rules and make exceptions in the existing rules when it is appropriate. The purpose of the Act is to ensure the efficiency and security of electricity supply in a socially acceptable way with a special weight on environmental protection as well as guarantee the consumers an access to cheap electricity (§ 1). The Danish Electricity Supply Act gives all customers the right to choose their producer and get transmission services from the responsible network against a fee (§ 6-7). The electricity transmission or distribution must take place in reasonable conditions and terms (§ 6). The customers of the collective network must pay to cover the necessary in the act specified cost of the party responsible of the system or of the network utility (§ 8–9).

The § 19 of the act states that the utilities operating transmission or distribution networks are required to have a concession that is given by the Ministry of Environment and Energy for a specific area. These utilities are responsible of the securing of an efficient and satisfactory transport of electricity as well as metering (§ 20). The tasks of the network utilities together with the utilities, that bear the system responsibility, include e.g. the requirement to maintain the technical quality of the network, measure the amount of electricity transported through the network, request the payments of the use of the network from the customers, distribute and bill the electricity, create transparency about the market situation and consult customers (§ 22). The Electricity Supply Act gives every party in Denmark the right to use the collective electricity network for the transport of electricity if they fulfil the required technical standards (§ 24-26). The act states that the network utility (or the party responsible for the system balance) sets the prices for the electricity transport (§ 25). Thus, the prices are not set by the Ministry or Energitilsynet. It is possible for the network utility to reject the transmission of electricity if the transmission capacity is scarce or lacking (§ 25)

The regulatory system in Denmark is based on income frames (§ 70). The Ministry of Environment and Energy sets income frames for the network utilities considering the expenses mentioned in the § 69. This paragraph states that the price of electricity distribution may include necessary expenses for energy, wages and other operating cost, administrative cost, operational depreciation and interest on borrowed capital. Provisions for new investments and interest on capital may be included in the price of electricity. The income frames also include a general yearly efficiency improvement requirement and individual efficiency improvement requirements set by Energitilsynet (§ 70). Energitilsynet accepts price setting after the notification of the utility (§ 71). The act concludes that the price setting specified in § 69-72 should take place in *reasonable, objective and non-discriminating manner* in relation to the cost that are caused by different customer categories (§ 73). All network utilities must notify Energitilsynet of the amount of their capital, which is the basis for the determination of acceptable income (§ 74).

According the Electricity Supply Act all electricity consumers are required to buy a share of their consumed electricity from renewable energy sources like wind power, decentralised heat and power production etc. that are called *priority production*. The priority production has a special price, which is not set under competition. For the households this means that they can effectively choose the supplier for the 60 percent of their demanded total electricity. The rest is formed from priority production. The amount of electricity that can be bought from the competitive market is thus expected to be about 14 000 GWh. The Act sets rules also for several other issues like system responsibility, balance maintenance, electricity production etc.

4.4.1.2 Principles

In the Danish system, the regulatory principles are fixed at the beginning of the regulatory period i.e. it is an ex ante system. The Danish regulatory system is an incentive regulation scheme due to the efficiency requirements defined in the Electricity Supply Act. The regulatory authority, Energitilsynet, defines the income frames for the period of four years with a yearly revision. The first regulation period is January the 1st 2000- December the 31st 2003. A new regulatory scheme came into force November the 11th 2001. Like already mentioned above, the frames are set so that the utilities can cover operative cost, depreciation and the return on capital for *efficient* operations. The utilities are allowed to keep the profit that they yield from efficiency improvements. Theoretically, this income frame system includes an incentive for efficiency improvements. (The income frame system is the revenue cap system discussed in chapter 3.6.1.) (EWI 2001, p. 27; Lavaste 2001, p. 36.)

The frames are set through a four-phase procedure: First, the operative cost is determined. It should cover the operation and maintenance cost of the network. There is a general requirement for efficiency improvement of three percent set by the Ministry of Energy and an individual efficiency improvement requirement set by the Energitilsynet, like discussed in the chapter above. An individual efficiency number for each utility is calculated according to the following equation:

(4.1) *Efficiency number = (labour cost / volume of the network) / correction multiplier.*

The labour cost includes the direct and indirect work cost as well as depreciation of capital. The correction multiplier determines the difference of cost between urban and countryside utilities. It is calculated with linear regression between the efficiency number and customer density of the distribution area.

The volume of the network is calculated with the equation:

(4.2) *Volume* = Σ *(the amount of network components * equivalent calculation unit)*,

where overhead lines, cables, electric stations, transformers and the customers are seen as network components. The equivalent calculation units are determined based on average labour cost of different components. One calculation unit is one kilometre of 0.4 kV cable. (Energitilsynet 2001b, p. 1; Lavaste 2001, p. 36; Møller Pedersen 2002, p. 2.)

The company whose efficiency number is the smallest is the most efficient and is considered 100 percent efficient. The efficiency improvement requirement is focused only on utilities whose efficiency number relative to the most efficient utility is below 80 percent. They are required to reach the 80 percent efficiency level during 2000-2003. (Energitilsynet 2001a; Lavaste 2001, p. 37.) Table 4.3 below presents the scheme of determination of the income frames in Denmark.

Second, a reasonable depreciation is determined. The purpose of depreciation is to recover future replacement investments starting from 2001. The Ministry sets them under a three percent efficiency requirement at maximum during the regulatory period. Thus, the individual efficiency requirement of cost allowed at maximum 20 percent and of depreciation 3 percent. Moreover, together all efficiency improvement requirements can be at maximum 20 percent (2 * 3 percent general requirement, the individual cost improvement requirement and the individual depreciation improvement requirement). (Energitilsynet 2001a.)

Third, the return on capital is evaluated. The return on capital is supposed to recover the cost of upgrading the network and the interests of own and external financing. The allowed rate of return is a sum of rate of return of obligations, supplements for the financing of extension investments and for acquisition of means of exchange as well as for the price increase of the investment goods. The higher the rate of own capital finance the smaller is the allowed rate of return. However, the capital return is *at least* one percent so that an adequate return on capital can be secured. (Lavaste 2001, p. 37.)

Fourth, other cost is determined. It is not set under any efficiency requirement, but is monitored by Energitilsynet. As a conclusion, the yearly income frames of the utilities are defined as a sum of these four factors. After the regulatory period, it will be determined for each year whether the cost or the income have exceeded or remained under the set limits. If the utility succeeds in saving, it may keep the gained utility in the height of five percent of the income frames. (Lavaste 2001, p. 37.) Thus, the cost and depreciation are benchmarked but the return on capital is not. It was considered that the benchmarking of depreciations induces enough pressure on efficient investments (Møller Pedersen 2002, p. 2.)

The Danish efficiency improvement scheme shows that the sum of the individual efficiency improvements of operational cost can be at maximum twenty percent. To ascertain the yearly individual improvement potential, the individual potential for efficiency improvements for 2002 and 2003 will be divided by two. The total sum of the improvements of the periods is allowed to be only twenty percent at maximum. Thus, the sum of the individual efficiency improvement requirement may be 14 percent at maximum because of the yearly three percent general requirements. For the year 2002, the Energitilsynet has set a cap of 4.5 percent for the individual efficiency requirement and for 2003 a cap of 9.5 percent. (Energitilsynet 2001a.) The Danish experience shows that especially large utilities are efficient but there are also small or medium size utilities among the efficient utilities. Therefore, the size of the utility is not the only factor influencing efficiency. (Møller Pedersen 2002, p. 3.)

Table 4.3: Determination of the income frames in Denmark.

Income frame regulation in Denmark 1.1.2000 - 31.12.2003

Phase 1: Operative and maintenance cost			
Efficiency improvement requirement	2002	2003	Sum
General	3 %	3 %	6 %
Individual (max)	4,5%	9,5%	14 %
Sum	7,5%	12,5%	20 %
Phase 2: Depreciation from the future replacement investments			
Individual efficiency improvement requirement (max)			3 %
Phase 3: Revenue of the network capital (sum of:)			
- Rate of return of obligations			
- Supplement for extention investments			
- Supplement for the acquisition of means of exchange			
- Supplement for the price increase of investment goods			
(no efficiency improvement requirement)			
Phase 4: Other cost			
(no efficiency improvement requirement)			

(Source: Own presentation.)

The Energitilsynet (2002, p. 5) has realised in 2002 that the set income frames have not been sufficiently strict in order to induce efficiency improvements. It has not been necessary for the utilities to start reducing their cost and they have collected even 134 000 euros less than the income frames would have allowed them to in 2000. The amount of investments has remained at the same level as earlier, only the share of external finance has risen. The network utilities have given up plans to raise the distribution tariffs, which however is not the result of the regulation but more the political decision of the executive committee of the utilities. There is still a long way to the realisation of the existing efficiency improvement potential. According to Energitilsynet, the long-term efficiency improvement potential is 50 percent of the present efficiency levels. This can be reached also through corporate mergers, co-operation and privatisation of the utilities.

According to Møller Pedersen (2002, p. 3), the main problem of this method (as with many other methods) is the different time perspectives of regulation and business activities. In Denmark, the regulatory method was introduced in 2000, but utilities have made decisions about their investments already years ago. The depreciations are benchmarked with the cost that the management of the utilities are able to influence, although these decisions were made long before the regulation. Thus, the depreciation cannot be influenced by the management in short or medium term. In addition, differing cost calculation practices between the utilities are also a problem of the Danish system.

In general, there is only little information available from Denmark. The regulatory scheme appears complicated and difficult. It is difficult to find explanations to the set caps on efficiency improvements. The system seems not to have been yet thoroughly considered and in practical implementation, it appears complex.

4.4.2 Regulation of Norwegian Network Utilities

4.4.2.1 Regulatory Institutions and Energy Act

In Norway, the main regulatory institution is the *Norwegian Water Resources and Energy Directorate (NVE, Norges Vassdrags- og Energieverk)*, which is a subordinated ministerial agency of the *Ministry of Petroleum and Energy* that bears the main responsibility for energy policy in Norway. NVE has operational independence and bears responsibility of setting guidelines in overall system operations, transmission and distribution tariffs as well as access conditions. It is also responsible for monitoring these functions and for the licence conditions for cross border trade. The NVE and the *Norwegian Competition Authority* have overlapping competences. There is, however, an informal agreement between these authorities according to which the NVE has the sole responsibility for regulating the network services. (IEA 2001, pp. 77-78.)

The Norwegian electricity market was opened with the *Act relating to the generation, conversion, transmission, trading and distribution of energy etc*. (Energy Act) already in 1991. The § 1-2 of the Norwegian Energy Act (here dating from January the 1st 2002) state that the main objective of the act is to secure that production, trade, conversion, transmission, distribution and use of energy takes place in a rational manner in accordance with the interests of the society. Thus, the law does not set any detailed rules on how to regulate networks but leaves the regulatory authority responsible for setting the regulatory frames. (Energy Act 2002.)

Production, transmission and distribution of electric energy need a concession. The same applies for the reconstruction or upgrading of existing installations (§ 3-1). The Ministry of Petroleum and Energy can grant a concession for construction or operation of electricity distribution network in an area up to a voltage level defined by the Ministry (§ 3-2). The party that owns the area concession is obliged to supply the geographical area for which the concession is valid (§ 3-3). Section four of the act states that a concession is also required for the trade of electricity.

The fourth section of the act further obliges the owners of electricity networks to open their networks to every party demanding network services in non-discriminating and objective point-of-connection tariffs and conditions. The Ministry has the authority to set rules on how the prices or earnings of the network services should be set and about the information the network companies must provide their customers. § 5A-1 states that parties bearing the responsibility of the system must secure the balance between production and consumption in the network at all times.

4.4.2.2 Regulatory Principles

The network regulation in Norway was based on rate-of-return regulation during the years 1992-1996. However, the NVE soon recognised the problems of this method (see chapter 0 above). According to NVE, the main problems were the inefficiency caused by the full recovery of the utility's cost and the lack of incentive to restructure the industry. Therefore, NVE decided to renew the regulatory system to realise possibilities for efficiency improvements. The new system was set for the five years period of 1997-2001. It is an income frame (a revenue cap) system similar to the one in Denmark. There is an upper and lower limit set to the revenue for each individual network utility every year. Utility's profit is the difference between the allowed revenue and the cost, which should give it an incentive to reduce cost. (Grasto 1997, pp. 7-8.)

The basic principle of the system is that the regulator fixes the yearly amount of income that each network owner is allowed to earn from tariffs. The cost of the network is considered to consist of operation and maintenance, capital cost like depreciation and return on invested capital, network losses and profit tax of 28 percent. In addition, the cost from having to purchase transmission services from other networks is added to the permitted income. All external cost to network activities is deducted to derive the net cost. The permitted income should cover these costs. The permitted income also includes a base return rate of capital of 8.3 percent. This base return rate is calculated based on an interest rate of the medium-term government bond with a two percent risk premium. Therefore, if the network owner wants to increase its return on capital (profit), he has to reduce his actual cost. Similarly, cost increases will reduce the capital return. However, there is an absolute upper limit set to the permitted return on capital, which amounted to 15.3 percent of the capital i.e. the profit on average should not exceed this percentage during 1997-2001. Further, an absolute minimum of 1.3 percent of capital return is defined so that no network company could run into deficit. (Grasto 1997, pp. 8-9.)

Analytically the method used in Norway can be written as:

(4.3)

$$IT_{e97} = \left\{ \frac{\left[\left(DV_{94} * \frac{KPI_{97}}{KPI_{94}}\right) + \left(DV_{95} \frac{KPI_{97}}{KPI_{95}}\right)\right]}{2} + \left(AVS_{95} * \frac{KPI_{97}}{KPI_{95}}\right) + \left[\left(BFK_{31.12.1995} * r\right) * \frac{KPI_{97}}{KPI_{95}}\right] + \left[\frac{\left(NI_{94}^{kWh} + NI_{95}^{kWh}\right)}{2} * P_{97}\right] \right\} * \left(1 - EFK\right)$$

where IT_{e97} = permitted income of the network utility, DV_t = net cost of operations and maintenance for the year t, AVS = linear depreciation of invested capital based on historic cost, NI^{kWh} = network losses in kWh (volume), KPI_t = consumer price index for the year t, BFK = depreciated historic cost of December the 31st 1995 (historic value), r = base rate of return, fixed at 8.3 percent, P_t = pool price of electricity in the future market for 1997 and EFK = general productivity requirement for 1997, set at two percent. The financial data of 1994 and 1995 has been indexed to the level of 1997 and a two percent productivity requirement has been reduced from the income in order to determine the permitted level of income. (Grasto 1997, pp. 9-10.)

The total permitted income can be expressed as

(4.4) $IT_t = IT_e + K_{ovf}$,

where IT_t is the total permitted income, IT_e is the permitted income in the owner's network and K_{ovf} is the cost that are incurred by transmission services carried out by external networks. If the actual income from tariffs exceeds the permitted income, the network utility has to pay back the undue profit (*windfall profit*) to the customers in the second year from the relevant financial year. Similarly, if the actual income is lower than the permitted income the firm is allowed to raise its tariffs in the second year calculated from the relevant year. The permitted income will be reviewed every year. A full review will be made every five years. (Grasto 1997, p. 11.)

The annual correction is as follows:

(4.5)
$$\mathrm{IT}_{e,n+1} = \mathrm{IT}_{e,n} * \left(\frac{\mathrm{KPI}_{n+1}}{\mathrm{KPI}_n}\right) * \left(1 - \mathrm{EFK}_{n+1}\right) * \left(1 + \frac{\Delta \mathrm{LE}_{a_{n+1}}}{2}\right) ,$$

where $IT_{e,n+1}$ is the permitted income in year $n+1$, $IT_{e,n}$ is permitted income in year n, KPI_{n+1} and KPI_n are the anticipated consumer price indices in years $n+1$ and n, respectively, EFK is the annual productivity requirement and ($\Delta \mathrm{LE}_{a_{n+1}}$) is the expected annual percentage change of the delivered energy. (Grasto 1997, pp. 11-12.)

Thus, the permitted income in second year equals the permitted income in first year multiplied with the relative change of the customer price index in second year (forecast) and with the efficiency requirement. This is further multiplied with the change of the distributed electricity in second year (forecast) divided by two. The last term should give the network owner compensation for the cost of new investments as well as a reward for a better utilisation of the existing network. (Grasto 1997, pp. 11-12.)

The correction for productivity improvement requirement consists of two parts: a general correction and an individual correction ascertained for each utility individually. In order to improve efficiency, Norway uses a non-parametric linear programming data envelopment analysis (DEA)–method[3] in order to determine individual productivity improvement requirements for the network utilities. Distribution network utilities have been subject to individual efficiency correction since 1998, regional utilities and the national network since 1999. (Lavaste 2001, pp. 34-35.) The general part is the same for every utility (1.5 percent). It is determined based on a study made by Førsund and Kittelsen (1998, p. 222) according to which the general productivity improvement potential of the Norwegian network utilities is 1.5 – 2 percent.

The individual part of efficiency requirement was fixed for 1999-2001. It was determined using factors like personal work years (amount), the amount of losses (MWh) and the monetary value of capital (lines, cables, transformers etc.) as inputs and factors like amount of customers, distributed electricity (MWh), length of lines (km) and length of sea cables (km) as outputs. Note, that the costs of the utilities are not considered in this assessment. By ascertaining the improvement requirement for each company, the efficiency of every utility was considered of being at least 0.7. The total efficiency requirement was set at maximum three percent annually. The average of total potential for efficiency improvement was 24 percent and the maximum 66 percent. (Lavaste 2001, pp. 34-35.)

For the next regulation period 2002-2006, the regulatory system was improved by taking a factor measuring quality into account. Every network utility was determined an individual efficiency aim for quality. If this is not reached, the allowed revenue will be reduced, if it is exceeded, the utilities will be allowed to have higher revenue than set at the beginning of the period. In other respects, the system is much like during the first incentive regulation period. As a basis for the determination of the revenue cap, the average operational cost of the years 1996-1999 and the depreciation of 1999 were used. The return on equity will be determined yearly unlike during the first phase. The risk premium is 2 percent and the efficiency improvement requirement is composed from the general 1.5 percent and the individual rate. The individual efficiency improvement rates were determined again with a new benchmark and got the values between zero and 5.2 percent. The effective return on capital was increased to maximum of 20 percent (from 15 percent) because, according to the network utilities, the revenue cap of the first period had not been adjusted to demand increase adequately. (Wild and Vaterlaus 2002, pp. 11-12.)

During 2002, the NVE launched several profound studies about the possibilities for a new regulatory regime. One of the projects is a study of ex post regulation, according to which the Norwegian regulatory authority is considering a transition into ex post regulation like in Finland and in Sweden starting from 2007 after the current regulatory period. (Agrell and Bogetoft 2002, p. 2.)

[3] The DEA-method will be described in more detail in chapter 5.4.1.

4.4.3 Supervision of Network Pricing in Finland

4.4.3.1 Responsible Institutions and Electricity Market Act

Three institutions are responsible for the matters concerning the electricity sector in Finland. The *Ministry of Trade and Industry* is responsible for the development of new legislation and issuing licences for the construction of high voltage transborder lines. *The Energy Market Authority (EMA)* is the main institution responsible for the supervision and monitoring of the network activities. *The Finnish Competition Authority* and the EMA have concurrent jurisdiction based on the *Act on Competition Restrictions*. (IEA 2001, pp. 56-57.)

The Energy Market Authority regulates electricity and gas business. The basic monitoring activities include:

– general obligations and pricing principles of transmission and distribution service providers,
– electricity retailer's obligation to deliver electricity and end-user prices.

The EMA is an advisor for other authorities, companies and consumers and a negotiator in the case of conflict. (IEA 2001, pp. 56-57.)

The Supreme Administrative Court has stated that the EMA has an extensive freedom of action in the development of criteria for reasonable pricing, because the Electricity Market Act does not specify, what level of pricing should be considered reasonable. Nor does it state what kind of process the supervisor should use in the evaluation of the level of reasonable pricing. (EMA 2001b, p. 26.)

The Finnish electricity sector is administered by the *Electricity Market Act* 386/1995, which came into force June the 1st 1995, and with the Electricity Market Statute 518/1995, which was later amended in 1997 and 1998. The first paragraph of the act states that the purpose of the law is to ensure efficiently functioning electricity market. An equally important goal is to secure sufficient supply of high-standard electricity at reasonable prices. These goals can be reached by securing a sound and well-functioning economic competition in electricity production and sales as well as reasonable and equitable service principles in the operation of electricity networks (§1).

Accorsing to paragraphs 9 and 10, the network owners are subject to three obligations particularly mentioned by the act. First, the grid operator should maintain, operate and develop his power network and the connections to other networks as well as secure the supply of sufficiently high-standard electricity to his customers (*obligation to develop the power network*). Second, the net operator should connect for a reasonable compensation such electricity consumption sites and power generating installations to his network, which meet the required technical specifications within his area of operation (*obligation to connect*). Third, the net operator is obligated to sell electricity transport services for a reasonable compensation to those who need them within the limits of his network capacity (*obligation to transmit*).

The distribution net operators must publish the general terms of connection for customers who connect to the power network at a nominal voltage of at most 20 kV and who are not power generating installations (§ 9). They must also publish the general terms of sale and the prices of his network services as well as the underlying criteria for price setting (§ 12). The sales prices and terms of the network services and the criteria according to which they were determined must be *reasonable, equitable* and *non-discriminating* to all network users. The pricing should allow for any terms needed for reliable operation and efficiency of the power system (§ 14). The price of network services within a distribution network must not depend on the geographical location of the customer within the net operator's area of responsibility, i.e. the pricing must be based on point-of-connection pricing (§ 15).

4.4.3.2 Supervision Method

The idea of the regulation method used in Finland is based on the assumption that the distribution and transmission companies are principally functioning according to the Electricity Market Act. Therefore, an ex ante regulation of distribution pricing is not necessary. The Finnish system is thus based on ex post supervision, which is a significant feature of the system. The supervisor cannot pre-impose service prices, pricing principles, forms of service or any other similar matters on the supervised companies. Every decision is made individually. This is the main difference of the Finnish system from the regulation methods applied in Norway and in Denmark. The supervisor can verify the lawfulness of pricing and require that it should be revised based on appeals or an investigation made by the supervisor itself. Thus, the EMA does not set the price; it just makes a judgement whether or not pricing has been lawful. The EMA can require the network utility to improve its pricing if it considers it unreasonable. (EMA 2001b, p. 27.)

The Finnish regulation system is a mixture of rate-of-return regulation and benchmarking. It is formed from two aspects: pricing must on the one hand allow the revenue to cover the reasonable cost of network maintenance, operation and construction and on the other to yield a reasonable return on the invested capital so that the firm is able to operate and stay in the markets. The capital return is determined by WACC (Weighted Average Cost of Capital) – method and the cost efficiency is ascertained with the DEA-method by comparing utilities' costs in order to create an incentive to efficiency improvements and cost reductions.

The supervision of network prices is built on the principle that pricing corresponds to operating cost. The present cost level of the utility is compared with the cost that the company would be capable of achieving if it functioned efficiently. The cost efficiency is determined with the DEA-method like in Norway. The Finnish model uses operating cost (as far as they can be controlled by the utility) as an input variable. The amount and the quality (moving average of customer's total interruption time) of the electricity distributed and the geographical dispersion of customers, which is approximated with the summed up network lengths of different voltage levels, are chosen as output variables. The number of customers characterises the operating environment. The efficiency numbers are applied in the evaluations concerning the reasonableness of the pricing of distribution of the year 2002, i.e. the first decisions will be made in 2003. (Korhonen et al. 2000, p. 111; Lavaste 2001, pp. 50-52.)

The EMA has decided to use the efficiency rates in the evaluation of the reasonableness of the distribution prices using the equation

(4.6) $$RC = (ER + 0.1) * OpC,$$

where RC = reasonable cost level, ER = company-specific efficiency rate, OpC = the company's controllable operating cost. Hence, the historical cost of the utility is multiplied with an individual efficiency number to determine the efficient cost of each utility. The EMA has decided to apply an error marginal of 0.1 to avoid situations where the firm would be set under unrealistic improvement requirements because there is always some uncertainty when using statistical methods e.g. due to possible measurement errors etc. If the efficiency rate exceeded 0.9, utility's reasonable cost would be higher than the actual cost and it would be granted an incentive bonus. That is, it is allowed to profit from its activities over the reasonable level with a corresponding sum. If the efficiency rate is exactly 0.9, utility's reasonable cost equals actual cost and no more measures result. If the efficiency rate were less than 0.9, utility's reasonable operating cost would be lower than its actual operating cost. Then, the utility has collected too much cost from its activities and the EMA can require it to improve its efficiency. An efficiency rate of 0.7 for example means that the company should reduce its input use by 20 percent in order to be considered efficient. (Lavaste 2001, pp. 50-52.)

One of the most relevant issues when evaluating the reasonableness of pricing is the measurement of the value of the invested capital. The EMA uses the current value of the distribution network. A reasonable return on invested capital is determined with a WACC model where the return on extern and own finance are ascertained separately. By defining a reasonable return on capital, the low risk content and the financing cost of investments as well as the long service life of equipments are taken into account. The allowable return on equity is estimated as the government's 5-year serial bond interest rate added by a risk premium of 1.5 percent.[4] The return on the extern capital is defined using the average lending rate of the total loan stock of the Finnish companies[5]. The acceptable return is thus defined as the weighted average of the return on own and extern capital. The used weights are the shares of own and extern capital, respectively. The depreciation from fixed assets should be based on the investments of the utilities. (EMA 2000, pp. 31-30; EMA 2001b, pp. 25-26.) This model can be criticised because the companies find out the acceptable rate of return for external capital only afterwards. Therefore, they cannot consider it in their planning.

The monopoly functions are considered more risk-free than many other forms of business and therefore the required returns should stay equivalently small. The risk premium of 1.5 percent is formed from two factors: the beta coefficient and the market premium. The beta coefficient (0.3) indicates the rate of risk of the monopoly's investments compared to the average risk of all investments in the economy. The market premium is five percent, which describes the rate of revenue that the shares produce on average in addition to a risk-free rate. Therefore, the risk premium is 0.3 * 5 percent = 1.5 percent. (EMA 1999, pp. 29-35.)

The final judgements about the performance of the utilities in respect of these two aspects will be divided into four different groups according to the need of improvement. If the cost and the return on equity are both reasonable, there is no need for improvement. If only the return on equity is too high, the utility is allowed to keep its incentive bonus but has to correct its pricing by that part of extra revenue that exceeds the incentive bonus. In a case when the cost is unreasonable but the return on equity is reasonable, there are two possibilities. The EMA can require that the utility corrects its cost structure, but it is still allowed to keep the return on equity. The other possibility is that the extra cost of the utility is compensated with the lower return on equity and the company could be required to take some corrective actions only if the difference of is positive. The fourth case is simple; if both the return on equity and the cost are unreasonable, the utility can be required take corrective measures. These should be taken within three months after the decision has been let known to the company. (Lavaste 2001, p. 53.)

The criteria for evaluating the reasonableness of pricing were made public at the beginning of 1999. The Energy Market Authority has issued a condemnatory decision about the pricing of three companies, Megavoima, Hämeenlinnan Energia and the energy utility of the City of Tornio in 1999. After a complaint of the utility, the Supreme Administrative Court issued its ruling about Megavoima in 2000, in which it verified the decision of the EMA about Megavoima having set its prices unreasonably high in 1996 and 1997. This decision meant that the Court considered EMA's method for evaluating the reasonableness of pricing of being in accordance with the Electricity Market Act. Hence, the rightfulness of the chosen regulatory

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4 In 2000, the government's 5-year serial bond was 5.27 percent i.e. the allowed return on equity was 6.77 percent.

5 In 2000, the average lending rate of the total loan stock of the Finnish companies was 5.97 percent.

system was confirmed. However, the Supreme Administrative Court stated that the EMA had exceeded its authority by specifying the calculations on which the tariffs are to be based. Thus, the EMA has mandate to oblige the firm to correct its pricing and to ensure that the corrective measures are sufficient, but not to order *how* these should be done. (EMA 2001a; EMA 2001b, pp. 26-27.)

Note that in Finland, the utilities do not have to return their extra profit to their customers. However, at the beginning of 2003 the Finnish Consumer Agency has decided to support a customer in his lawsuit against his electricity distributor. They sued Fortum Oy based on the decision of the EMA of 2001 according to which the utility has charged too high distribution prices. The customer wants to get compensation for the unreasonable pricing. If they win the case, it might become a precedent case, which might lead to a new practice, according to which the utilities must start paying their excessive income back to their customers. This would certainly support the learning effect of the utilities in the market. However, if the utility wins the case, the effect might be the exactly opposite even degrading the foundations of the actual regulation. In February 2003, the Ministry of Trade and Industry has established a committee to suggest how to improve the system and to consider possibilities of compensating the customers. (Kuluttajavirasto 2003.)

Up until now, the utilities in Finland have not had to pay the cost of interruptions to the customers. This is about to change because the summer and fall 2002 were very stormy and a lot of people were left out of electricity for several days due to storm damages in the electricity lines. In Finland, the largest share of electric lines is overhead lines and therefore the electricity networks are very sensitive to extreme weather occurrences. The Ministry of Trade and Industry suggests that the utilities must compensate their customers for an interruption, if it lasts longer than 12 hours. This naturally increases the cost of utilities as well as the cost of repairs. It remains to be seen whether this practice leads to increased investments and to replacement of overhead lines with cables. If this development takes place, it is most likely that the investment cost of single utilities will increase thus leading to price increases.

4.4.4 Monitoring of Network Tariffs in Sweden

4.4.4.1 Authorised Institutions and Swedish Electricity Act

In Sweden, the institution mainly responsible for electricity sector is the *Ministry of Industry, Employment and Communications*. The *Swedish National Energy Administration (SNEA)* was founded in 1998 to be responsible for the implementation and co-ordination of energy policy and network regulation. Its task is monitoring the network tariffs and other conditions. It has the power to accept or reject the tariffs set by the electric utilities. Also in Sweden, a separate *Competition Authority* deals with application of competition rules. (IEA 2001, pp. 83-84, SNEA 2002a, p. 14.)

A principal difference of the Swedish legislation, which makes it differ from the legislation in other Nordic countries, is that the *Swedish Electricity Act* from 1.1.1996 (here referred the amendments dating from November the 1st 1999) requires a separation (unbundling) of all electricity companies and distributors into individual companies. Thus, legal entities involved in electricity generation or trading are not allowed to operate networks and vice versa. Network operation must always be carried out as a separate business. (Chapter 3, § 1.) An annual report shall be submitted to the network authority and must be made publicly available. Accounting and bookkeeping of network operations must be kept separately from any other activities. (Chapter 3, § 2.) Therefore, every customer in Sweden has two agreements, one with the network company and the other with the electricity supplier. (Unipede 1998, p. 36; VDEW 1999, p. 11.)

The *Swedish Electricity Act* defines two types of networks: the ones who are required to obtain a concession and the ones who are not. Only those that are obligated to have a concession are regulated by the act. Those utilities that have a concession are called network owners and the others property owners (fastighetsägare). There is a concession for an area or for a line (Chapter 2, §1-2). The act states that the network conditions shall be based on the protection of public interest (Chapter 2, §10). The utilities that have possession of the area concessions have more obligations and their activities are regulated more that those that have a line concession. The holder of a network concession is *obliged to connect* customer's lines and installations (Chapter 2, § 6) and to *transmit* electrical power for others on reasonable terms (Chapter 2, § 9). Further, it is obliged to *meter* the quantity of the transmitted electrical power and its distribution over time (Chapter 2, § 10).

The network tariffs should be reasonable, which - from the point of view of the customer - is understood to mean stable and low prices and - from the network utilities point of view - a moderate return. Tariffs must also be objective and reasonable. (Chapter 4, § 1.) The country is divided into concession areas. Within these areas, it is forbidden to have different prices for the same kind of customers based on their geographic location (Chapter 4, § 3). (SNEA 2002b, p. 13; Sveriges Riksdag 1999.)

4.4.4.2 Supervision of Network Tariffs

Like Finland, Sweden uses an *ex post regulation* method. This means that the prices are monitored individually for each utility after each period. It is considered that the electric utilities should be able to guide the development of the sector themselves. It is based on regulation-by-rights idea (Agrell & Bogetoft 2002, p. 71). The used regulation method was based on "a factor price index" meaning that the development of the network tariffs should follow the general development of input prices. In addition, a general requirement for efficiency improvement ("a rationalisation factor") was taken into account. (SNEA 2002d, SNEA 2002b, p. 11.)

However, this method has been considered inadequate and therefore the regulatory authority has suggested a network utility model, Nättnyttomodellen, (or "ideal net model" (Agrell and Bogetoft 2002, p. 72)) in order to improve the general efficiency of companies. It is based on the measurement of the difference between the utility the customer experiences and the revenue received by the company. (SNEA 2001b; Lavaste 2001, p. 31.) This method has been applied gradually and in 2003 the third round of testing the regulation method was started including more utilities.

Most models developed to increase efficiency try to determine whether the resources invested in the network activities are set efficiently. The judgement of that has been considered complicated. In the network utility model, the approach is different. The method does not regard the efficiency of the used resources. It has been thought that the network company is allowed to have as much revenue as it offers utility or value to its customers. Thus, this model is used to supervise the revenue of the utilities. The method is a fictive network method similar to the fictive cable method discussed earlier. (See chapter 2.4.2.) (SNEA 2001b; Lavaste 2001, p. 31.)

The customer utility is equal to a *network performance* multiplied with a *quality surplus*. To derive the network performance a fictive network is established. It is formed of high and low voltage lines, the frontier points between regional and local network, electric stations and the customers point of connection. The cost of this fictive network equals the network performance.

In the calculation, the used cost is what has been considered standard in the sector. For example, the depreciation is calculated based on 30 years lifetime and the capital productivity is four percent added with a two percent risk premium. The quality surplus is calculated based on the cost of one interruption of electricity transmission that the customer has to bear. This cost is related to the network performance. Finally, the quality surplus is calculated from the quality cost. Utilities that have low relative quality cost get a large quality surplus and vice versa. (Lavaste 2001, p. 31.)

The network utility is compared with the volume of sales of each company. A cost function is formed with the help of linear regressions based on the relation of the network performance and the turnover. The companies that lie far away from the cost curve are taken into closer consideration. Hence, the network utility model can be seen as a way to separate those possibly inefficient companies from others. (Lavaste 2001, p. 32.)

The new idea is to benchmark the annual cost efficiency with the DEA-method like in Finland and Norway. The efficiencies are calculated for both short and long run, which enables the consideration of factors that are fixed at the short term but can be improved in the long term. In the short run model, the operative cost are used as inputs and total network length, installed capacity, transformation stations divided by the installed capacity as well as the climate as environmental variables. The distributed electricity both high and low tension, customers in both tension levels and maximum distributed power are considered as outputs. In the long term, the outputs remain the same, but the inputs are variable cost, network losses and network capital. The fictive network length and the climate are applied as environmental factors. (SNEA 2002b, p. 18.) The major weakness of the Swedish regulatory system is that it is not definitely fixed even after a long period of intensive research.

4.5 Discussion and Conclusions

A close co-operation in the electricity sector takes place between the Nordic countries already for several years. Regular cross-border electricity trade takes place and a joint electricity exchange is in action. However, the countries differ quite significantly in the structure of electricity production. Geographical factors set challenges to the distribution and transmission networks.

Firms' structures vary between the countries. Sweden is an exception among these countries because the Swedish legislation requires a total unbundling of electric utilities' activities into distribution and transmission in one part and into generation and trade in the other part. The structure of ownership of the electric utilities varies from privately owned to municipal distribution utilities. There have been no attempts to privatise electric utilities in any of these countries. However, large generation companies buy other generation and network utilities, which increases the concentration in the sector. The corporate mergers take place also across the border; Vattenfall is already very active in the Finnish market and Fortum Oy enhanced its market position in Sweden by buying Birka Energi. Chapter 4.2 showed that concentration in the generation sector is rather high.

The liberalisation of the Nordic electricity sector is based on regulated third party access, which is the prevailing form of market regulation. Each Nordic country has founded a specific institution responsible for the regulation of the network pricing. The regulated third party access avoids the weakness of the negotiated network access -system where utilities can abuse their market power because the contract conditions and prices cannot be supervised efficiently. The benefit of a regulated system is that all actors in the market face the same conditions, which creates transparency in the market contributing to reduced monopoly powers and to non-discriminating prices. Hence, the attempt is to level the playing field for all customers.

Each regulator in these countries strives for efficiency improvements. The regulatory authorities in Finland and Norway evaluate the performance of the network utilities by comparing them with the other firms in the sector by forming a benchmark. The advantage of this approach is that the companies do not benefit by reporting their costs falsely because the result of regulation depends also on the performance of all other firms in the sector. However, these schemes and the legislation to fulfil this task differ in method and in detail. Table 4.4 below presents a summary of the principles of the regulatory methods in these countries.

Finland and Sweden base their regulation schemes on ex post price supervision i.e. the reasonableness of pricing is reviewed after the price-setting period. In Denmark and Norway, the allowed income is set beforehand (ex ante). If the revenue cap is exceeded, the firms will be required to pay the extra revenue (windfall profit) back to the customers. This is a difference when comparing with the ex post systems, where the utilities do not have to pay compensation to the customers. With the ex post supervision, the decisions are made individually for the affected utility and thus these systems rely much on the learning effect of the other companies in the sector, which is considered to take place easily because the regulation method is considered transparent and simple. The performance is supervised every year. The ex ante regulation is considered to be more inflexible and slow mainly because the regulatory period is often several years long. Ex post supervision, nevertheless requires for a *high degree of transparency* in pricing.

Table 4.4 Summary of the regulatory schemes in the Nordic countries.

	DENMARK	FINLAND	NORWAY	SWEDEN
approach	ex ante	ex post	ex ante	ex post
method	income frames	cost efficiency, rate-of-return	income frames	network utility, network performance
regulatory period years	4	1	5	1
unbundling	accounts	accounts	accounts	operations
cost covering	operative, maintenance cost, depreciation	operative cost	operative cost, depreciation, maintenance, network losses	cost of fictive network
efficiency improvement	yes	yes	yes	yes
efficiency improvement %	general 3%, individual max. 20%	individual, based on DEA	general, 1.5%; individual, based on DEA	individual based on DEA and customer utility
incentive	may keep the cost reduction up until 5% of the frames	if > 90% efficient, incentive bonus	may keep the cost reductions	-
rate of return	sum of diffent factors	WACC-model	return on invested capital 8.3%	-

(Source: Own presentation.)

All regulatory methods have some advantages and shortcomings. No method is perfect, because it is impossible to design a manageable method that takes into account all factors that influence the operational environment of the network utilities. For example, the ability of the Danish system to measure efficiency can be criticised because it does not measure the efficiency of the use of capital at all. It also does not consider any differences in the quality of electricity or in the general operational environment. The method used in Norway can be criticised because the benefits received from the efficiency improvements go mainly to the owners of the companies, not to the customers. The possible 20 percent return on invested capital is rather high for such low risk monopoly actions. The development of the consumer price index and the increase of distributed electricity might exceed the efficiency improvement requirement thereby fully offsetting it. The Norwegian system is slow in realising efficiency improvements, because e.g. the new revenue caps that are set for the period 2002-2006 are based on historical cost information from 1996-1999. Thus, the system is partly based on six years old information. The advantage of these systems is for example that the utilities can consider the set income frames during the regulatory period and adjust their operations to these set constraints.

Ex post supervision requires a high degree of transparency in pricing. Reliable information must be provided about the unbundled business operations. The system also requires a certain level of activity from the supervisor's part and short processing times for appeals about prices that do seem to be reasonable. However, setting rules in the markets is difficult and slow in respect of the needs of the market, which can be considered a lack of the system. Starting an appealing process might prolong the time span during which the firm can continue its unreasonable pricing policy. Another problem might arise from the fact that the decision holds only for an individual firm and cannot be directly generalised. If other firms will not learn from this process, it means a heavy workload for the supervisor.

The Finnish electricity market legislation gives the regulator a lot of freedom on how to design the regulatory system. The expression "reasonable pricing" also leaves a lot of room for interpretations. Auer (2002, p. 101) criticises ex post systems because companies are studied only based on complaints from customers, which he considers unfair. According to him, complaints will be issued most likely about companies that have high prices although their prices might be altogether justifiable due to e.g. structural reasons. Thus, according to his view the system does not treat all companies equally. This argument can be questioned since for example in the case of Finland the EMA initiates supervisory processes also on its own, partly based on efficiency numbers, not only on complaints. Companies are treated fairly and equally because all companies are aware of the regulatory rules, thus, the system is transparent. In addition, each company received its individual efficiency number two years before the system was applied in the supervisory practice. Hence, the companies had two years time to adjust and improve their relative efficiency positions before the efficiency study was applied in the regulatory practice. Also in Sweden, the firms that lay further from the cost curve i.e. seem to be inefficient are examined more closely from the own initiative of the regulatory authority.

One of the main advantages of the Finnish system is that the regulatory effort of the supervisor is low, which brings flexibility and lightness into the system. In addition, the regulatory organisation remains flat and small. Only those firms are investigated that are suspected of unlawfulness. Due to the large amount of firms operating in the sector it is considered that an ex ante approval method would increase the workload of the supervisor substantially. The individual firms have in any case best information for forming their tariffs. It can be expected that they are aware of the criteria on which the reasonable pricing is based and therefore most of the firms independently choose the right price levels because they wish to avoid the negative publicity that would result from an investigation process.

The lack of the Swedish fictive network method is that it does not take into account the historical development of firms' structures, which mostly explains capital structures of the firms today. On the other hand, the fictive network method delivers an objective measure for technical efficiency, according to which the network utilities orient themselves in the real life decision making. The advantage of this model is that it is unambiguous and it is difficult to manipulate by the companies. Therefore, it avoids the problem of asymmetric information. In addition, this method is manageable from the regulatory point of view and creates transparency within the system. A disadvantage of this method is the lack of consideration of any geographical or other environmental factors.

Thus, the Swedish efficiency improvement practice is a long run process, which delivers a measure for technical efficiency based on the difference between the true network construction and the technically possible structure. A problem is how to measure the cost of interruption for different customers and how to build the quality surplus that treats all utilities equally irrespective of the customer structure. In practice, the main problem in Sweden has been the appointment of a clearly defined method, i.e. the establishment of reliable regulatory frames. Hence, the regulatory practices face different problems. In the following chapter, the cost efficiency and pricing of the individual network utilities will be studied considering the functional environment.

5 NETWORK PRICING IN THE NORDIC COUNTRIES

5.1 Introduction

In the last chapter, regulation systems and market structures in the Nordic countries were described. In this chapter, the objective is to study the tariff setting of the utilities and the efficiency of their performance. A very relevant issue in the evaluation of efficiency in the electricity network is how differences in costs and efficiency should be considered and how these differences influence the reasonableness of pricing of the network services.

The study relies on the main assumption that network utilities set their prices based on their cost. Therefore, differences in prices can be explained by differences in cost. Network utilities usually argue that differences of cost are caused by differing environmental circumstances. Thus, the problem of pricing was first approached by studying which environmental or structural factors influence the cost or price and how large the influence is. The study was executed with an ordinary least squares regression analysis. The main result was that the chosen environmental factors explain only a small percentage of the cost or the price. Hence, the conclusion was that differences in cost or price are a result of inefficiency of operations. The efficiency was studied to be able to make conclusions about the efficient costs of the utilities. The efficiency study was executed with data envelopment analysis that delivers efficiency scores for the studied utilities based on comparisons with the most efficient utilities.

Hence, this chapter focuses on making conclusions about the cost efficiency of the utilities and the reasonableness of pricing as well as some conclusions about the efficiency of the regulatory practices in the electricity distribution network based on empirical information. The objective is to make judgements whether the prices set by network companies can be considered reasonable and well founded and whether the monopoly companies receive monopoly rents based on empirical information. The information used in this study is mostly published in the internet by the respective regulatory authorities based on yearly reports from the companies.

Chapter 5.2 studies the tariffs within and between the chosen types of customers in these four countries. The chapter also analyses the structure of the distribution tariff, whether it is a fixed charge or variable demand based charge etc. Chapter 5.3 considers the factors influencing the operational environment of the utilities as well as the informational requirements affecting the study. Chapter 5.4 considers the cost efficiency of the utilities and presents the applied method: data envelopment analysis. Chapter 5.5 studies the development of prices after the beginning of liberalisation in these countries. The last chapter makes a short conclusion of the findings.

5.2 Structure of Tariffs

5.2.1 Comparison of Tariffs in the Nordic Countries

This chapter focuses on price information. In general, there are several prices offered by the network companies for the use of network. To ease comparison between companies, the respective national authorities publish prices for chosen types of customers that are presented in Table 5.1. Unfortunately, the types of customer are not identical between countries, which makes the direct comparison of pricing difficult.

Table 5.1: Types of customer in the distribution networks.

Customer Group, kWh/year	Denmark	Finland	Norway	Sweden
Household, small apartement	2000	2000	x	2000
Household, small apartement	4000	5000	4000	5000
Agriculture	x	10 000	x	x
Farming	x	35 000	30 000	30 000
Small house with separate electric heating / room	x	18 000	x	20 000
Small house with electric heating	15 000	20 000	20 000	25 000
Small-scale industry	100 000	150 000	160 000	100 000
Small-scale industry	250 000	600 000	x	350 000
Medium-sized industry	1 000 000	2 000 000	1 600 000	x
Medium-sized industry	1 000 000	10 000 000	4 000 000	5 000 000
Energy-intensive industry	x	x	x	140 000 000

(Sources: Dansk Energi 2002b, EMA 2003, NVE 2002b, SNEA 2002c.)

As can be expected, tariffs differ in their height between countries as well as between types of customers. Figure 5.1 below presents the network prices without taxes as well as the price variance (minimum and maximum prices) for four chosen types of customer that are most alike between the countries (compare with the Table 5.1 above). A general practice is that households that have the smallest yearly demand on electricity pay the highest prices whereas large-scale industry pays the lowest. This is due to, for one reason, that the cost measured per kWh is lower when the demand is higher because of large fixed cost. Economies of scale also play a role because the marginal cost of an increase of electricity consumption is very small compared to the total cost, which leads to lower prices per kWh. In addition, the large-scale industry can exert market power to demand lower prices, because in some cases it even has the means to built a connecting line directly to some power plant or even built an own power station relieving itself from the dependency on the network altogether.

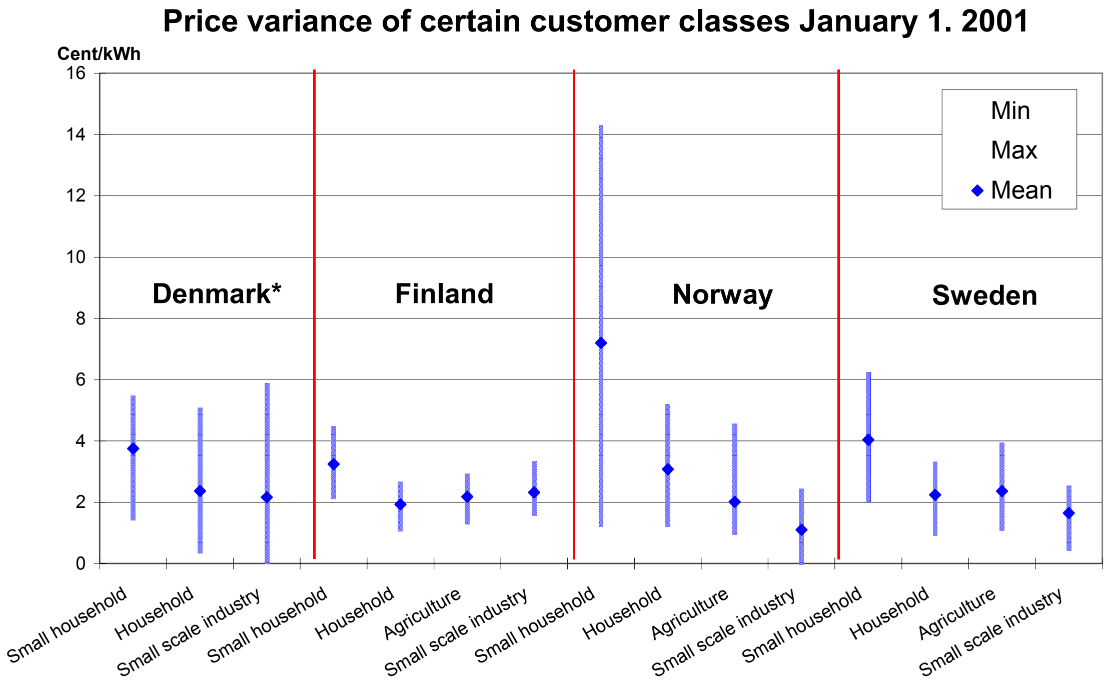

Figure 5.1: Mean, minimum and maximum prices in 1.1.2001[6].
(Source: Dansk Energi 2002a; EMA 2002; NVE 2002b; SNEA 2002c[7].)

Table 5.2 below shows the cost of different types of customers in Sweden as an example. It can be seen that the costs rise per kilowatt-hours when the consumed energy decreases. The difference in cost is quite impressive. The cost of apartments is ten times higher than the cost of energy intensive industry. Network tariffs are subject to specific electricity taxation that differs in these countries. The prices are also subjected to value added tax.[8] Here, all prices are considered without taxes.

6 Denmark* = prices January the 1st 2002.

7 The prices for Denmark are calculated from tables 23. 31-351, 353, 355-533, 543 and 552-911. The prices for Finland are taken from EMA's January "keskihinta" -tables published for each month in the webpage of the EMA. The prices for Norway are set together from NVE's price tables published in the Internet for different areas of the country. The prices for Sweden are set together from SNEA's internet price tables for households up to 20 MWh yearly demand, for enterprises up to 350 MWh/year and for enterprises up to 140 GWh/year.

8 In Denmark there is 0.005 cent/kWh (0.04 øre/kWh) electricity distribution tax for distribution. In Finland there is an electricity tax of 0.42 cent/kWh for the industry and for the other customers 0.69 cent/kWh. There is also a so-called supply security payment of 0.13 cent/kWh for all customers. VAT in Denmark is 25 percent, in Finland 22 percent, which are also paid from the electricity taxes enforcing their influence, in Sweden 25 percent and in Norway 24 percent, although the Nordland, Finnmark and Troms areas are exempted from VAT.

Table 5.2: Network costs of consumer groups in the distribution network in Sweden.

	Voltage	Demand/Fuse	Energy	cent/kWh
Electricity-incentive company	130	20 MW	140 GWh	0,33
Company (high demand and voltage)	40	5 MW	25 GWh	0,67
Company (low demand)	10	1 MW	3,5 GWh	1,53
Industrial / Commercial entity	0,4	300 kW	750 MWh	2,42
Mixed agricultural entity	0,4	35 A	35 MWh	2,23
Household with electric heating	0,4	20 A	20 MWh	2,29
Combined heating (oil/electricity)	0,4	16 A	19 MWh	1,59
Single family household	0,4	16 A	5 MWh	3,50
Apartment	0,4	16 A	2 MWh	3,74

(Based on: Unipede 1998, p. 41.)

A consideration of the overall price level in these countries shows that the price level was quite the same (see Figure 5.1 above and Table 5.3 below) in these countries in January 2001. The average industry prices (demand 100-160 MWh/a) were the lowest in Norway and Sweden and the average prices for both households (5 and 20 MWh/a) were the lowest in Finland. For agriculture, the prices were almost at the same level in all of the countries (except for Denmark, for which there was no information available). Based on an average of the prices of these chosen types of customers, Finland and Sweden have the lowest prices. Table 5.3 presents also modal prices that lie in most cases for households 20 MWh and small-scale industry slightly below the mean meaning that the price level based on most commonly applied tariffs might even be lower whereas for the households 5 MWh in most cases higher. (Appendix B presents price tables for all published types of customers in these four countries.)

A closer look at the network prices shows that the range of the prices is very large i.e. the highest tariff is 100 percent and in most cases even more expensive than the cheapest within one type of customer. Like the figure shows, in Finland the mean prices varied the least between different customers. In absolute prices, the average difference between the lowest price and the highest is in Denmark 4.76 Cent/kWh, in Finland 1.7 cent/kWh, in Norway 5.66 cent/kWh and in Sweden 2.76 cent/kWh. In case of Norway, the price for small households is not quite comparable with the other countries because in Norway this customer classification includes leisure apartments and cottages instead of the normal all-year-round dwellings. In Norway, the prices for the large-scale industry were on average only 0.63 cent/kWh and 0.42 cent/kWh for the demand of 1.6 GWh and 4 GWh respectively, whereas in the other countries, the price is over one cent/kWh for utilities with demand of 1-5 GWh.

Table 5.3: Prices of the chosen types of customers in 1.1.2001.

		Min	Max	Mean	Modal
Denmark	*Household 5 MWh*	1,48	5,40	3,75	3,88
	Household 20 MWh	0,40	5,00	2,37	2,03
	Agriculture	-	-	-	-
	Small-scale industry	0,06	5,81	2,16	1,70
Finland	*Household 5 MWh*	2,19	4,41	3,24	3,81
	Household 20 MWh	1,13	2,59	1,93	2,05
	Agriculture	1,36	2,86	2,18	2,11
	Small-scale industry	1,63	3,26	2,32	2,30
Norway	*Household 5 MWh*	1,26	14,23	7,20	7,30
	Household 20 MWh	1,26	5,13	3,08	2,73
	Agriculture	1,02	4,48	2,01	1,96
	Small-scale industry	0,03	2,36	1,10	0,66
Sweden	*Household 5 MWh*	2,09	6,17	4,04	3,83
	Household 20 MWh	0,98	3,24	2,24	2,00
	Agriculture	1,14	3,87	2,36	3,07
	Small-scale industry	0,50	2,46	1,64	2,04

(Source: Dansk Energi 2002a; EMA 2002; NVE 2002b; SNEA 2002c.)

In Finland, the variance of prices of the firms is relatively small at least compared to its neighbours. This could imply that the utilities face similar costs and set efficient prices based on the costs but it could also mean there is some kind of consensus within the industry considering network pricing. This, however, is unlikely considering the large amount of utilities in the sector.

5.2.2 Structure of the Danish Network Tariffs

Network prices in Denmark are formed from three main elements: a *subscription/power payment*, an *energy fee* and an *investment contribution* that is paid once when the customer is connected to the grid or when the size of the connection is increased. The subscription payment is a fixed fee paid annually that varies according to the voltage of the connection whereas the power payment is charged per ampere. The energy fee is charged based on demanded kWh. (Dansk Energi 2002b, p. 8.)

There are differences in the price between parts of the country and between customer types. Especially, there are differences between areas to the west and to the east of the Great-Belt as well as between large and small (often private) customers. Prices are higher on the Danish islands in the east than on the continent. Larger customers will usually pay according to a three-period tariff whereas small customers pay a unit price. (Dansk Energi 2002b, p. 8.)

5.2.3 Tariff Structures in Finland

In Finland, customers get the right to use the whole network of the country when connected to the national grid. In 2000, the elements of the national grid tariff were *a market place charge*, which is based on access to the network, *a use of grid charge* based on consumption further divided into summer and winter times. From 2002, the *loss charge* is solely charged from producers differing from the earlier practice, according to which it was charged also from the customers. End customers pay for the cost of the national grid even though they do not necessarily use it. The use of grid charge is calculated based on actual power flows. From 2002, there is also a *market frontier charge*, which is focused on import and export of electricity from the neighbouring countries. Tariffs are independent from the location of the power producer. (Fingrid 2002.)

The tariffs in the distribution network in Finland are based on two basic principles. First, the purpose of the tariff is to cover the cost of distribution of electricity to the network company. Second, the tariff should treat all customers equally. Hence, this requires that the cost of adding a new customer to the network will be collected from every new customer in form of an access payment. (Lemström and Pirilä 1998, p. 2.)

The tariff system in the distribution network depends on the size and load pattern of the customer. The EMA publishes prices for 10 consumer classes (see Table 5.1 above). Some independent producers are directly connected to the medium voltage network (6-20 kV) and some few consumers directly demand electricity from the medium voltage network. The tariff structure of the medium voltage network for customers and the producer charges are the same. However, producers can get compensation of maximum 25 percent for the electricity that they inject to the network. (EMA 2002; Teijonsalo and Antila 1998, pp. 4-6.)

Distribution tariffs for consumption in the low-tension network include three basic parts: a fixed fee, an energy fee and possibly a power fee. There are also three sorts of tariff components: *a general distribution fee*, *a time distribution fee* and *a voltage fee*, which are further divided into the above-mentioned basic components. Figure 5.2 below demonstrates the structure of the tariffs in Finland.

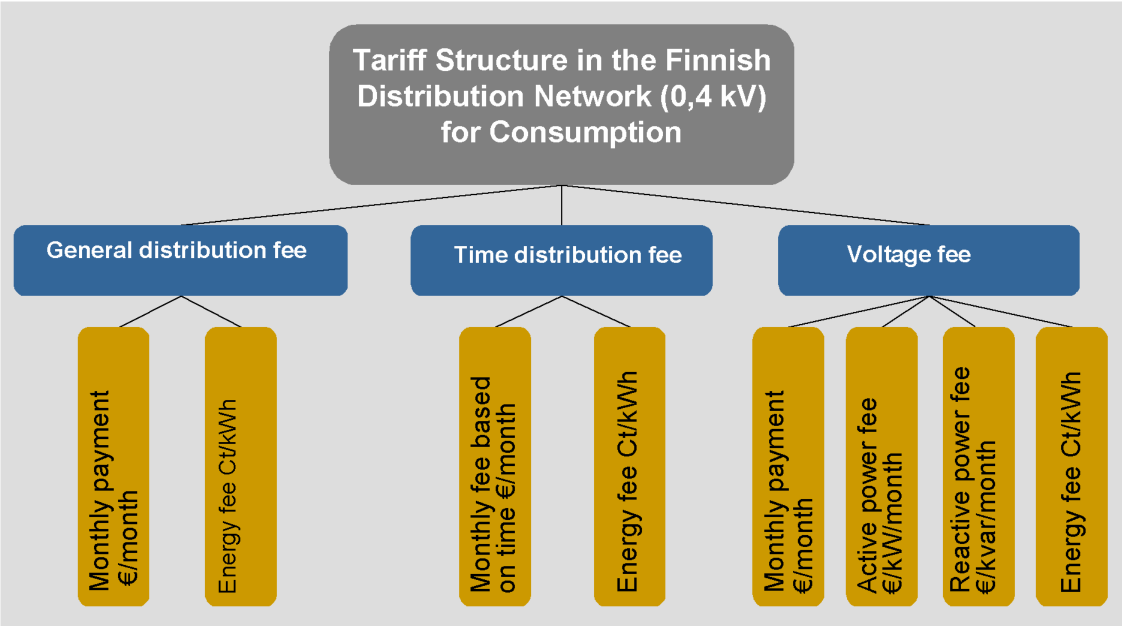

Figure 5.2: Structure of the distribution tariffs in the low voltage network in Finland. (Based on: EMA 2002.)

Thus, the tariff component usually includes a fixed fee and an energy fee that is charged based on the amount of distributed electricity. The monthly payment in some form prevails in almost all distribution utilities as a part of their tariff. The fixed fee usually depends on the size of the main fuse. The share of the fixed part of the total tariff varies in general between 0-80 percent. In Finland, the prevailing view is that a tariff based only on an energy fee does not correspond to cost and discriminates customers that use a lot of power. Respectively, high fixed charges discriminate small users.[9] (EMA 2000, p. 14; EMA 2002; Kärkkäinen and Farin 2000, pp. 19-23.)

Tariffs are often divided into high or low priced tariffs based on the time of demand. There are large differences between the network owners in the definition of time and voltage tariffs. There are variations within the day, week and season, which makes it difficult for customers to compare prices. A study made by Kärkkäinen and Farin (2000, p. 58) recommends that firms should be able to choose their tariff structure freely so that the cost of electricity distribution will be covered the most efficient and to local conditions most suitable way. However, they suggest that the cost of the metering devices and services should be differentiated from other fixed fees because metering is not a service that can be offered only by natural monopolies.

5.2.4 Network Pricing in Norway

In Norway, there is a postage stamp -like pricing system based on nodal pricing in the transmission network, i.e. tariffs refer to each separate node in the interconnected network system. The optimal price is defined as the *value of marginal losses* and the *cost of capacity constraints* measured at any node of the system, which produce a pricing system based on short run marginal cost and thus create an optimal dispatch in the network. Prices are based on the

[9] See chapter 5.2.5 for the practice in Sweden, where the trend is moving totally to fixed fees in the household sector.

spot price that reflects the short run marginal cost in every node in the system at any time. The problem discussed in chapter 2.4.3 that variations in spot price cause high differences in tariffs, was first solved in Norway by using an average loss-factor. From 1998, the loss factors are calculated every 8 weeks based on expected average flow in the network. (Amundsen et al. 1998, p. 4; Sagen 1998, pp. 3-8.)

However, these tariff components based on short run marginal cost cover on average only circa 30 percent of the total network cost. To price scarce capacity in the network, a bottleneck fee is added to the spot price in all nodes where there is surplus in demand and subtracted in all nodes where there is surplus in supply (generation). The bottleneck fee is set based on information from the bidding in the spot markets. Therefore, the prices of electricity transmission explicitly reflect the cost of congestion and should thus be relatively close to efficient tariffs. (Sagen 1998, pp. 4-8.)

The transmission network tariff is formed from four elements: a connection charge, a power charge, a congestion charge and a loss charge. The *connection charge* is a pure access fee designed to cover the fixed cost of the network utility. In practice, it is a load based tariff component related to the maximum load of the users. For the generators, it is related to the maximal generation capacity of the power plant during wintertime. The *power charge* will be levied based on physical power flows. Revenue from the power charge formed 45 percent of the volume of the transmission company Statnett in 1998. The *congestion charge* is designed to signalise scarcity of the network capacity and its costs caused by out of merit generation and consumption. *The loss charge* reflects the value of physical marginal losses caused by line flow. Both the customers and the producers are subject to these charges. (Perner and Riechmann 1999, p. 219; Sagen 1998, pp. 4-8; VDEW 1999, pp. 10-11.)

Before 2001, the generators and the end-customers have covered the network cost of the national grid through tariffs in equal shares. However, to ease the generators task of providing more electricity to meet the growing demand of electricity, end-customers pay 60 percent of the cost starting at the beginning of 2001. It was considered that customers are more dependent on high delivery quality than producers are and therefore should pay a higher share for the quality. (Statnett 2001, p. 11.)

This general structure of the transmission tariffs cannot be directly applied to the pricing of distribution, because it would lead to unacceptable price differences if each customer had an individual price based on its point of connection. Thus, similar customers in a licence area have the same tariff according to the voltage level, utilisation time etc. In the distribution network, the energy component reflects average losses of the licence area. Thus, it is not differentiated for the point-of-connection. (Unipede 1998, p. 34.)

When customers connect to the network, they must possibly cover a part of the initial investments when these are particularly high. The distribution tariffs have *a variable element* and *a fixed element* that is differentiated according to type of customer in three classes (households, smaller firms and holiday homes) and given as a fixed price per customer per year. The variable part of the tariff might be *a power fee* (NOK/kW) or *an energy fee* (NOK/kWh) that covers firms' variable costs. The power fee is not used for households and leisure apartment customers. For the industry, the height of the power fee rises according to the tension level. (Unipede 1998, p.34.)

In Norway, the share of the fixed fee from the total distribution fee varies less than in Finland. The fixed fee is at highest approximately 50 percent of the tariff. Some utilities set the fixed fee higher for the leisure apartments (consumption 4000 kWh/a). Some single utilities also introduce lower fixed fees for customers that have lower yearly demand. Some utilities have a differentiation on time or on geography of energy fees. The NVE publishes prices as they are reported. It cannot guarantee that they are calculated based on common calculation guidelines. In addition, it is possible that in practice the utilities offer also other tariffs than what they report to NVE. To be able to reduce prices for end customers, it is even suggested that certain high price utilities should receive a governmental supplement to cover the missing income due to reduction of prices in order to guarantee the attainment of the yearly income frames set by the regulator.

5.2.5 Structure of Swedish Network Prices

The pricing system of the national grid in Sweden is similar to that of Norway. The *point-of-connection tariff* gives the customer access to the complete national network. The point-of-connection tariff comprises an annual *power charge*, an *energy charge* to cover transmission losses and a once-for-all *connection charge*, which is an investment contribution. The power charge is latitude-dependent because the main power flows take place from north to south. Generators pay higher injection fees in the north where there is surplus in generation. They pay less in the south where the load centres and export markets are located. There are also areas with negative producer tariffs meaning that producers get compensation of the produced electricity. Respectively, consumers will pay more in the south and less in the north. The power charge from national grid customers accounts for approximately 60 percent of the revenue of Svenska Kraftnät. Principally, the customer bears the cost of the national grid only as much as he uses the grid. (Perner and Riechmann 1999, p. 214; SNEA 2001a, p. 28; Svenska Kraftnät 2001, p. 5.)

The energy charge is designed to cover the losses of the national grid. The loss charge varies with the geographical location like the power charge. It can be positive or negative, since in certain locations the network losses are reduced. (SNEA 2001a, p. 28.) The energy and the power fee are designed to reflect in a simple way the short term or long term cost of injected and discharged electricity. This should signal customers of the efficient use of the network.

In Sweden, there is no direct congestion charge like in Norway. This is the main difference between the systems. Therefore, the price system does not reflect congestion in the network and thus does not induce efficiency. Therefore, there is excess demand of transmission capacity from time to time, which leads to bottlenecks in the system as well as different price areas. In a case of bottleneck, the Svenska Kraftnät balances the market by counter-trades during the times when there is congestion in the system. The extra costs of these interventions are mainly covered by fixed charges on the users of the transmission system. The most important bottlenecks take place between northern and middle Sweden (capacity limited to 6700-7000 MW), between middle and southern Sweden (3500-3900 MW) and between southern Norway and Sweden. (3000 MW). (SNEA 2001a, p. 28; Statnett 2001, p. 12.)

The tariff system in the distribution network depends on the size and load pattern of the customer. Usually, the Swedish network company's tariff structure is formed from a demand related tariff for every transformation step and for every line voltage classified into normal and short utilisation. It is also formed from a fuse related tariff on low voltage for apartments, for short and long utilisation time and with two energy charges. Figure 5.3 below illustrates the tariff system. (Unipede 1998, p. 39.)

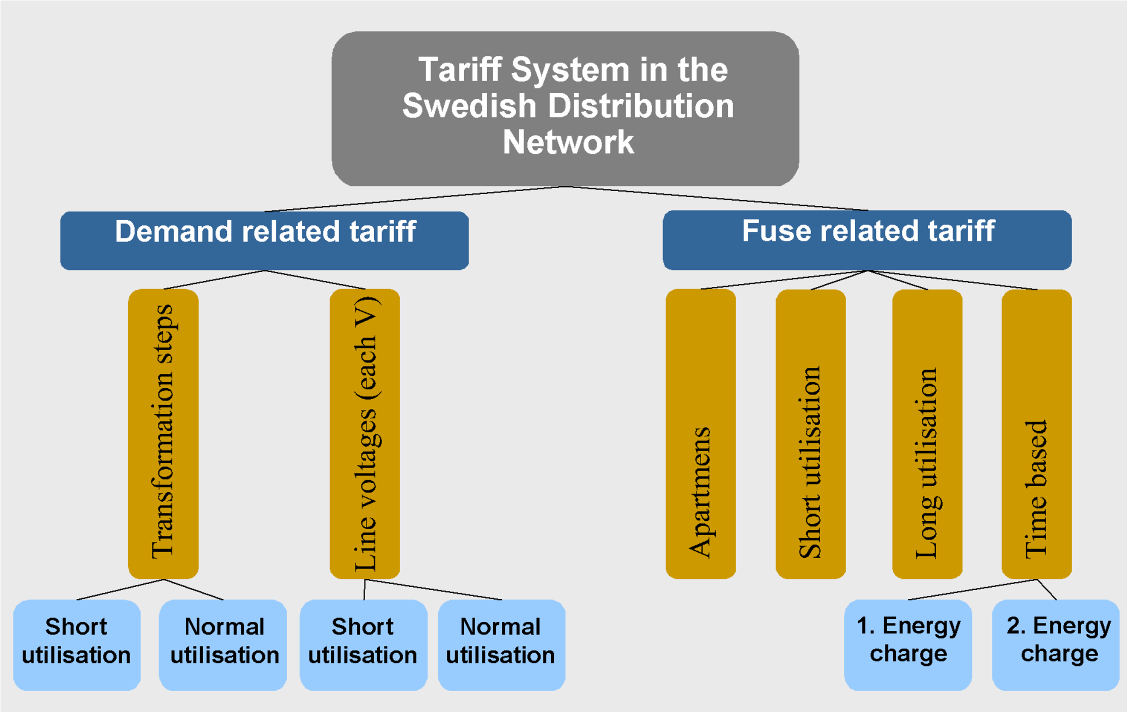

Figure 5.3: Tariff system in the Swedish distribution network.
(Based on: Unipede 1998, p. 39.)

The tariff element is determined by the respective cost element, which is demonstrated in Table 5.4 below. These structures are valid for the low (0.4 kV) and sub-transmission (20-130 kV) voltage distribution network. (Unipede 1998, p. 40.) Here, it can be seen that the fixed charge is based on the characteristics of the customer. The costs of local networks are covered by a demand charge as SEK/kWh whereas the network losses are covered by an energy charge as öre/kWh.

Table 5.4: Tariff and cost elements in the Swedish local distribution network.

Consumers with demand-metering

Tariff element	*Cost element*
Fixed charge (SEK)	Customer-related cost
Contractual demand charge (SEK/kW)	Demand-related cost (local network)
Peak load demand charge (SEK/kWh)	Demand-related cost (national network)
Energy charge (two levels)(öre/kWh)	Energy-related cost (network losses)

Low voltage consumer, demand less than 120 kW, fixed charge based on main fuse of 16-200 Amps

Tariff element	*Cost element*
Fixed charge (based on main fuse) (SEK)	Customer-related and local demand-related cost
Energy charge (one or two levels)(öre/kWh)	Energy-related and national demand-related cost (network losses)

(Based on: Unipede 1998, p. 40.)

In Sweden, the trend has been towards the reduction of different tariff forms. Many companies just offer one tariff whereas for example in Finland there is a lot more variation in the tariff alternatives. The two countries differ also in the weight of the tariff structure between fixed and energy fee. In Sweden, especially the users with low consumption are put into a less favourable situation because often the largest part of the tariff is formed from a fixed tariff. Sometimes even the whole tariff is fixed so that the amount of distributed energy is irrelevant. In Finland, the case is exactly opposite. There, some utilities charge households based on the distributed electricity (as cent/kWh) only. Norway lies between these two extremes. (See also Israelsson and Lindström 2001, p. 11 for more about this issue.)

5.3 Operational Environment and Structural Factors

5.3.1 Data and Data Requirements

To be able to make any conclusions about network pricing, it is necessary to have detailed statistical information from each utility. It is also important that this information be attained from a reliable source. In this study, information was obtained from the regulatory authorities of the respective countries. Therefore, the used data can be considered reliable. This study was made possible by the fact that good quality statistical information is published separated only for the distribution network. Internationally, the Nordic countries are an exception, because of the high quality of relatively independent and numerous observations.

However, the availability of information posed limits to the realisation of the study. The largest problem posed Denmark, where no statistical information for individual distribution utilities was placed at public disposal. The exception was price information, which is not published by the regulator but by the Association of the Danish Energy Companies. Therefore, due to the missing empirical information Denmark had to be left out of the efficiency studies.

The most central issue is to know the height and the kind of cost the network utilities face. If the cost is not known, it is possible to make assumptions about the cost structure of the company if physical information about the network and company structure (length of electric lines, amount of cables, transformers, amount of personal etc.) is available. Information about the operational environment (size of service area, amount of customers etc.) as well as their prices is also necessary. This was done for example in recent studies about the German electricity distribution sector (see Haupt et al. 2002; Pfaffenberger et al. 2002). Yet, if financial information is directly available, it is preferable to use it.

There are, however, several problems when comparing cost derived from annual financial statements between individual companies, not to mention between countries. Differing bookkeeping practices lessen the direct comparability of the network utilities. This is the reason why most regulatory authorities have set guidelines on how to register and report financial information. Unfortunately, these guidelines differ and the specific sources of cost are defined differently in the three Nordic countries. This makes a more accurate and detailed study impossible. Thus, the different operational cost listed in cost sheets were just aggregated for each company in each country.

However, it is generally acknowledged that only such costs that can be influenced by company's management should be taken into consideration in the efficiency studies. The largest group of cost that the companies cannot influence are payments to the upstream high-tension networks. For Finland and Norway, these costs are separately listed for each network utility but not for Sweden. For example in Finland, the cost of the overlaying network was on average 0.4 cent/kWh with a range of 0.06 – 1.08 cent/kWh. In Finland and in Norway in 2000, the payments were on average approximately 25 and 26 percent of cost, respectively. According to a study of the Swedish utilities (SNEA 2002a, p. 30), these costs form 23 percent of the operational cost of the distribution network utilities yearly.

Another difficulty emerges from the typical structure of the electricity distribution. Production of network services for different customers is typically joint production. The same production resources are also used to deliver network services to different users of the network at the same time. Thus, the problem is how to allocate the right share of the used resources to right customers. What share of the total cost should a certain network user bear? This problem of joint production appears horizontally as well as vertically. Vertical combined production means production for customers in different tension levels, whereas horizontal combined production means production for customers with different demand characteristics. (See also Haupt et al. 2002, pp. 21-22.)

The other side of the same problem emerges when trying to compare price information with the cost. Utilities do not publish any unique price per kWh but instead prices are published for several different types of customer. Inter-country comparisons make the issue even more complicated since types of customer are not classified alike in these countries. This means that either the cost must be divided to the right type of customer with some kind of key or an average price must be formed. In this study, the latter approach was chosen because, on the one hand, information about the cost of a specific customer group is not available. On the other hand, according to Fritz et al. (2002, p. 387) the results would not be accurate if the network cost and prices were considered separately for a single group of customers because there are interdependencies between groups of customers that help reduce cost in all groups.

Thus, to enable the comparison an average price must be formed. To determine an accurate price the prices can be weighted based on information about the maximum power (MW) of certain type of customer for each company or on how much electricity (MWh) is distributed to each type of customer. In general, it can be expected that the costs will be recovered, i.e. highest prices will be set to customers whose demand is the most inelastic. Unfortunately, information about consumption or maximum demand for individual customer types is not available either. The arithmetic averages of prices would also lead to biased results. Therefore, a price based on the volume of sales (volume of sales / amount of distributed electricity) was chosen as a reference for this study.

5.3.2 Value of Capital

When studying network pricing, an important factor is how to evaluate capital and depreciation because network industry is very capital intensive. Capital cost can be evaluated differently depending on the way of bookkeeping. One alternative method to evaluate capital is the present value method. In this case, the problem is that information about the age of the network investment is often not available for company external studies. Capital can be of different age and the old investments might already be amortised while the new is still unpaid. Another alternative to evaluate capital is the replacement value in present prices. This method, however, over-estimates the value of the network. A compromise might be that some percentage of the replacement value is considered as an estimate of the present value. For example, according to a study made by Lassila et al. (2002) for the Finnish Energy Market Authority it is thought that 50-55 percent of the replacement value would be an acceptable estimate of the present value of the network. In this study, depreciation and capital were taken as the regulator publishes them because it is impossible to try to start determine them according to some specific method. According to an efficiency study of the NVE, the difference in efficiency measured by bookkeeping and market values was only one percent. Thus, the influence of this factor seems to be rather small. (Lavaste 2001, p. 35.)

Another issue is that utilities also have a lot of freedom of choosing the suitable rate of depreciation of their investments. It is possible to depreciate the investment at high rates, which means that a large part of it is expensed as cost. The utility does not appear very capital intensive but seems to have high cost, which lessens the profit. The alternative is to depreciate in small rates, which makes the utility appear capital intensive. It depends, among other things, on the regulation method which practice is the most profitable to the company. For example, if the regulatory system focuses on minimising cost (like in Finland for example) it is obviously more attractive to the company to have smaller depreciation rates. Further, if the return on equity is granted as a percentage of the capital then this alternative allows higher absolute capital returns thus leaving room for monopoly rents.[10]

In this study, the choice of an appropriate return of capital was considered difficult. The return of external capital is usually the market interest rate, which in 2000 was about 5-6 percent on average in these countries. The cost of external capital is the interest payments and therefore it is considered together with cost. The problem is the own capital finance because the return on equity is much more difficult to determine. On the one hand, there should be incentives for the investors to invest into the networks, thus a reasonable return should be granted. On the other hand, monopoly rents should be limited. It is generally considered that the return on equity can be modest because the monopoly business is rather risk-free. In this study, three capital return rates were tested: six, ten and fifteen percent, which lie between the rates practiced in the Nordic countries. (In Norway, the maximum return on invested capital was 15 percent in 2000, in Finland 6.77 percent.)

5.3.3 Regression Analysis of Structural Factors

The differences in the network price between companies are most commonly explained by structural differences that influence the cost and thus the price. This issue is widely discussed and the literature generally acknowledges that e.g. the structure of the service area does influence cost. In Finland, Norway and Sweden, population density is low in most parts of the countries. In large parts of the countries, there are a lot of overhead lines. Overhead lines and cables have different investment cost as well as different maintenance cost. For example, the overhead lines are obviously much more sensitive to extreme weather occurrences than underground cables whereas the installation cost of cables is higher than the installation cost of overhead lines. The question is whether such regional distinctions explain differences in prices *adequately*. In fact, a study about the pricing of German network utilities (Haupt et al. 2002, p 39) shows that no statistically significant dependencies between prices and the chosen structural factors could be determined except for the location of the companies in eastern or western part of Germany.

In the case of the Nordic countries, the *ordinary least squares* (OLS) regression analysis explaining cost shows a little bit different results. Here, for example, the ‘line lengths in kilometers’ are used as an approximation of the size of the service area. ‘Lines per customer’ approximate how densely the service area is populated and ‘megawatt hours per kilometer of lines’ approximate the efficiency of the use of existing lines. The indicator ‘megawatt hours per customer’ indicates the structure of customer types in the area. If the ratio is high, there are lot of large customers and possibly industry; if it is low, the customers are presumably mostly less consuming households. The ‘uninterrupted time’ approximates the quality of electricity distribution. The ‘cabling ratio’ is an indicator of the structure of the service area. A high

[10] This is a sort of Averch-Johnson –effect described in chapter 3.

percentage of cables of the total amount of electric lines is considered to reflect a town-like agglomeration structure and a small percentage of cables reflects more rural areas.

The results of the regression analysis with total cost as dependent variable are listed in the Table 5.5 below.[11] Geological differences could not be directly tested because there is no such information available for single network utilities. It cannot be ruled out that special geographical circumstances could have a significant influence on cost.

Table 5.5: Results of a regression analysis, dependent variable total cost in cent/kWh.

Dependent variable: Cost and return on equity in cent/kWh (Finland, Norway and Sweden in 2000)												
Nr.	Constant	Energy (MWh) / lines km	Energy (MWh)	Uninterrupted time h	Customers	Line length km	Lines km / customer	Energy (MWh)/ customer	Customer / lines km	Cabling ratio %	R2	F-value
1	2,66	-0,0004	x	x	x	x	x	x	x	x	0,13	69,40
2	2,61	x	-0,0000003	x	x	x	x	x	x	x	0,07	33,85
3	2,49	x	x	-0,0006	x	x	x	x	x	x	0,0008	0,37
4	2,60	x	x	x	-0,000006	x	x	x	x	x	0,05	25,31
5	2,52	x	x	x	x	-0,00002	x	x	x	x	0,01	2,58
6	2,31	x	x	x	x	x	1,274	x	x	x	0,03	16,31
7	2,50	x	x	x	x	x	x	-0,0002	x	x	0,01	5,27
8	2,94	x	x	x	x	x	x	x	-0,042	x	0,15	82,06
9	2,16	x	x	x	x	x	x	x	x	0,008	0,06	31,76
10	2,48	-0,0003	x	-0,0002	-0,000004	x	x	x	x	0,006	0,20	28,07
		=statistically different from 0 with 95 % significance level based on t-test corrected with White Test for heteroskedasticity										

(Source: Own calculations.)

Some of the correlation coefficients are significantly different from 0 according to their t- and F-values, but the coefficient of determination (R^2) shows that they alone explain only a small percentage of the cost and capital revenue in cent/kWh. The only factors that have a larger influence on cost in cent/kWh are ‘MWh per kilometer electric lines’ and ‘customer per kilometer electric lines’ as can be expected since they approximate the efficiency of the use of networks. Thus, they indicate how many customers the utility can provide or how much electricity it distributes per kilometer of line. The line lengths as such are not significant in explaining cost.

The regression analysis with the average price in cent/kWh as a dependent variable shows that the ability of these factors to explain prices is quite similar as in case of cost (see Table 5.6). The price equals volume of sales divided by the amount of distributed electricity. Here also, ‘MWh per kilometer electric lines’ and ‘customer per kilometer electric lines’ are the largest explaining factors by 14 and 15 percent respectively. This, with the result above, indicates that the weight put on structural differences is much exaggerated. The same factors are significant according to both regressions.

[11] The regressions are calculated in case of heteroskedasticity with White’s test, which gives consistent estimates also in the presence of this specific data problem.

Table 5.6: Results of a regression analysis, dependent variable price in cent/kWh.

Dependent variable: Price in cent/kWh (Finland, Norway and Sweden in 2000)												
Nr.	Constant	Energy (MWh) / lines km	Energy (MWh)	Uninterrupted time h	Customers	Line length km	Lines km / customer	Energy (MWh) / customer	Customer / lines km	Cabling ratio %	R^2	F-value
1	2,59	-0,0003	x	x	x	x	x	x	x	x	0,14	72,39
2	2,54	x	-0,0000002	x	x	x	x	x	x	x	0,06	29,74
3	2,45	x	x	-0,0001	x	x	x	x	x	x	0,0001	0,03
4	2,52	x	x	x	-0,000004	x	x	x	x	x	0,04	17,27
5	2,46	x	x	x	x	-0,000003	x	x	x	x	0,00	0,21
6	2,31	x	x	x	x	x	1,029	x	x	x	0,04	17,11
7	2,46	x	x	x	x	x	x	-0,0002	x	x	0,02	7,84
8	2,80	x	x	x	x	x	x	x	-0,033	x	0,15	79,86
9	2,24	x	x	x	x	x	x	x	x	0,005	0,04	19,50
10	2,48	-0,0003		0,0001	-0,000003					0,003	0,17	23,92
		=statistically different from 0 with 95 % significance level based on t-test corrected with White Test for heteroskedasticity										

(Source: Own calculations.)

The last case of both regressions considers some indicators together that appear to have the strongest influence on cost / price. By choosing these indicators, each factor was used only once. Thus, because 'MWh per kilometer electric lines' was chosen as one indicator, no other factor including line lengths could be chosen. In both cases, R^2 is somewhat higher.

Other factors beside the structural factors, that have an influence on the cost comparison between countries, are e.g. the differences in prices of cost carriers. For example, labour costs differ between these countries, which naturally influences the cost level of all network utilities. Some of this influence is however captured by the exchange rates. There are also regional differences in costs within a country, on which the utilities cannot have any influence. Unfortunately, these differences could not be taken into account in this study because such information is not available.

Filippini and Wild (2002, p. 54) list environmental factors that cannot be influenced by the network utilities:

– regionally different prices of production factors
– differing cost structure (the cost is dependent on the customers structure)
– differences between the average consumption between customer groups
– differences in the customer density of the inhabited area
– differences in the share of buildings outside of the inhabited area
– differing conditions for the building and managing of electric lines.

The cost of the companies may also be influenced by the ownership structure of the network utilities. Municipally owned companies may follow other objectives than merely cost minimisation. These utilities may function as a political tool for example to support local employment. Alternatively, the emphasis of company spending might be focused on environmental improvements, which shifts the focus away from cost minimisation. Empirical information in the case of Norway supports the suggestion that municipally owned companies might not operate in a cost minimising manner. In Norway, networks are mostly owned by local utilities and the following efficiency study shows that there the cost efficiency is at the lowest level compared with its neighbours. In addition, it can be questioned whether the managements of publicly owned utilities have incentives to improve efficiency in the markets if they do not directly gain from it.

The incentives might be at a very different level in privately owned utilities, where the payments to managers might even be linked to the success of the utility. There is evidence that also privatised companies with weak corporate governance demonstrate low performance. Empirical results of the Swedish electricity retail distribution show that privately owned firms are relatively more efficient than the municipal companies (Kumbhakar and Hjalmarsson 1998, p.117). The study of Bagdadioglu et al. (1996, p. 20) about the efficiency of chosen Turkish electricity distribution utilities, however, revealed no significant difference between private and public distribution utilities.

5.4 Analysis of Efficiency

5.4.1 Data Envelopment Analysis

The method used to evaluate the efficiency of the network utilities was a non-parametric linear frontier method called *data envelopment analysis (DEA)* that is commonly used especially in efficiency studies of electric industry.[12] The DEA efficiency concept was first developed by Farrell in 1957. Charnes, Cooper and Rhodes developed his concept further from a single output/input ratio to multiple output and input case (CCR-ratio) in 1978. Färe, Grosskopf and Lovell (1985) have further extended the model of constant returns to scale to case of variable returns to scale in 1985. (Charnes et al. 1994, pp. 4-6; Coelli et al. 1998, p. 133; Färe et al. 1994, pp. 8-9). The Norwegian and Finnish regulatory authorities use this method in their regulatory practice to form a benchmark in order to evaluate the cost efficiency of the network utilities.

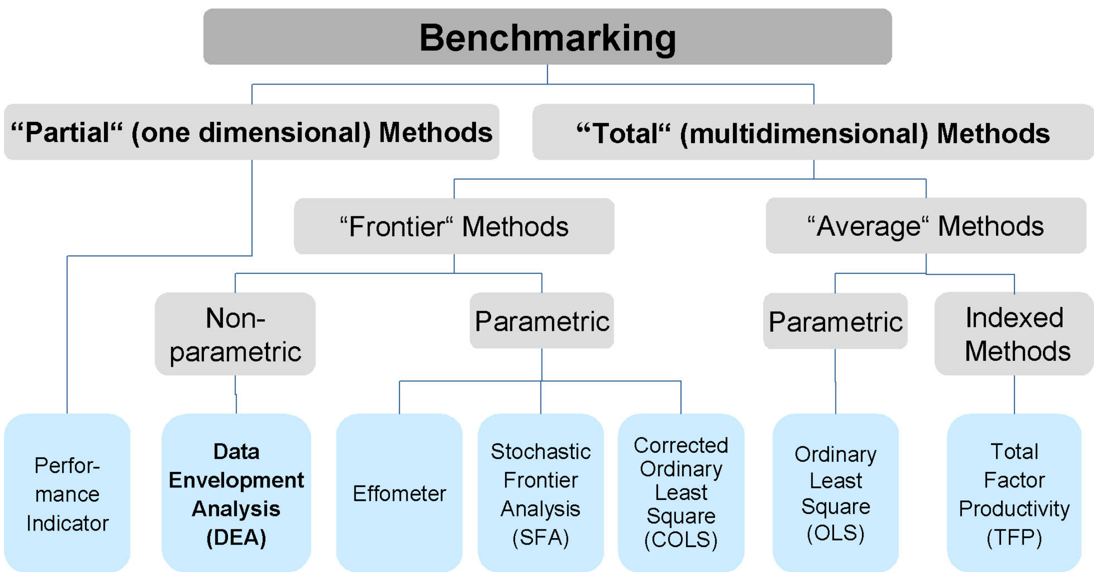

Figure 5.4: Overview of the different benchmarking techniques.
(Source: Auer 2002, p. 30.)

[12] For example, Zhang and Bartels (1998) have studied the mean efficiency of the electricity distribution in Australia, Sweden and New Zealand, Burns et al. (1999) in Great Britain, Bagdadioglu et al. (1996) in Turkey, Resende (2002) in Brazil, Pacudan and Guzman (2002) in the Phillippines and Førsund and Kittelsen (1998) have studied the shift in the frontier technology in the Norwegian electricity industry.

There are both *parametric (stochastic)* and *non-parametric* approaches to evaluate firms' performance. The difference between the parametric and non-parametric methods is that the parametric methods require an imposition of a specific functional form as well as assumptions about the distribution of the error terms. For example, the common ordinary least squares method (OLS) and the *Stochastic Frontier Analysis* (SFA) are parametric methods that deliver a functional form of the inputs and outputs. Non-parametric methods, like the DEA, imply that there is no functional connection between inputs and outputs. The DEA calculates a maximal performance for each network utility relative to all other utilities with the only requirement that each of them lies on or below the efficiency frontier that represents a linear combination of the most efficient utilities. Figure 5.4 above presents an overview of the different benchmarking methods. According to a study of Granderson and Linvill (1999, p. 226), the parametric and non-parametric methods do not greatly differ in their results. In fact, according to them, differences between the methods indicate the ability of the utilities to manipulate the regulatory environment.

In the DEA-method, the relative technical efficiency is understood as a ratio of the weighted sum of outputs to the weighted sum of inputs of the utility. The weights are selected so that they deliver a Pareto-efficiency measure for each utility subject to a constraint that no utility can have a relative efficiency score greater than one. Firms that minimise their inputs for a certain output or respectively firms that maximise their output with a certain amount of inputs can be considered efficient. Efficiency can be composed of two factors, so-called technical efficiency and allocative efficiency that together form a measure for total economic efficiency. The allocative efficiency requires though that the prices of inputs and outputs are known. (Burns et al. 1999, p. 287; Charnes et al. 1994, p. 6; Coelli et al. 1998, p. 134.)

It is important to note that the DEA delivers only measures for *relative* efficiency. The DEA calculations are thus designed to maximise the relative efficiency measure for each utility[13]. DEA produces a piecewise empirical extremal production surface, which represents the *revealed best-practice production frontier*. In case of input-orientation, it is the minimum input empirically obtainable from any utility in the observed sample given its level of output. For each inefficient utility, the sources and level of inefficiency can be determined by comparing with a single efficient (benchmark) utility or with a convex combination of other referent utilities located on the efficient frontier. The determined improvements are indicative of potential improvements obtainable, because the projections are based on the revealed best-practice performance of comparable utilities that are located at the efficiency frontier. (Charnes et al. 1994, pp. 6-7.)

The regulator can choose an input or an output oriented approach depending on his preferences. In the case of electricity distribution, the *input oriented approach* is naturally in the interests of the regulator, since it focuses on cost minimisation. In addition, in the electricity distribution industry the network utilities have in general very little influence on the demanded amount of electricity. Thus, an output oriented approach is not suitable in the measurement of the performance of the electricity distribution utilities.

Figure 5.5 presents a simple situation for two inputs and one output. The inputs most often used in case of electric industry are operative costs or overhead costs and as outputs the amount of transported energy (kWh), maximum power (MW) or the amount of customers. It is also possible to take into account environmental and structural factors. They can include for example customer density, change in consumption or some geographical or climate indicators. (Auer 2000, pp. 40-41; Coelli et al. 1998, p. 166.)

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[13] The DEA literature commonly uses the expression DMU, "decision making unit", instead of utility or firm etc.

Depending on the preferred criteria, the regulator defines the efficiency level. If the aim is to maximise the allocative efficiency, then the line pp in Figure 5.5 presents the efficiency frontier. It is formed by the relative prices of the inputs 1 and 2. In this case, only the firm R is producing efficiently. If, however, the regulator wishes to maximise the technical efficiency, firms U,V,W,R and Z form the frontier. This frontier is called *technically efficient frontier*. In this case, only the technical efficiency is considered and the other firms than firm R on this frontier are not expected to be allocatively efficient. Technical efficiency thus means the relation of inputs to outputs (see the axis descriptions) without considering the price of inputs. A technically efficient utility can produce a certain combination of outputs with the minimum inputs. Firms S and T are inefficient in both respects. Their technical efficiency level is presented by 0S'/0S and 0T'/0T respectively, where S' and T' are the projection points on the efficient frontier. (Coelli et al. 1998, p. 135; Korhonen et al. 2000, p. 44.)

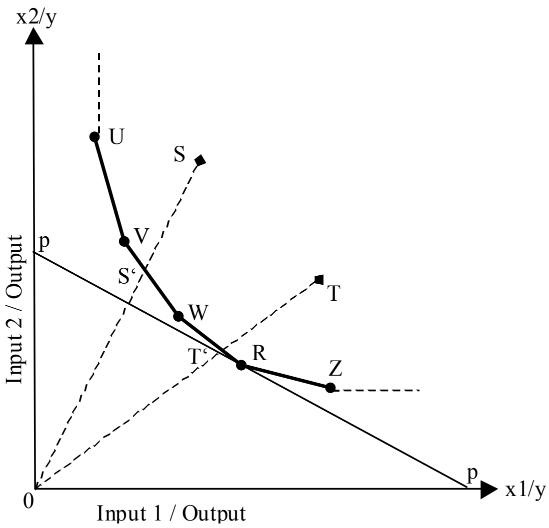

Figure 5.5: DEA-efficiency frontier from the input perspective.
(Source: Coelli et al. 1998, p. 135; Korhonen et al. 2000, p. 44.)

A model based on constant returns to scale is appropriate only when companies are operating at an optimal scale. There are many reasons why a utility might be working at a non-optimal scale, such as constraints of finance or imperfect competition or demand fluctuations of the customers. Thus, in this study, an approach based on variable returns to scale was chosen. Formally, the model for variable returns to scale is:

$$(5.1) \qquad Max\ h_0 = \frac{\sum_{j=1}^{n} u_j y_{j0} - c_0}{\sum_{i=1}^{m} v_i x_{i0}}$$

subject to

$$(5.2) \qquad \frac{\sum_{j=1}^{n} u_j y_{jk} - c_0}{\sum_{i=1}^{m} v_i x_{ik}} \leq 1 \text{; k = 1,...,K,}$$

$$(5.3) \qquad u_j, v_i \geq 0 \quad \text{; i = 1,...,m; j = 1,...,n;} \quad c_0 \text{ is unlimited.}$$

h_0 = efficiency number of unit, y_{jk} = output j produced by unit k, x_{ik} = input i consumed by unit k, u_j = weight of output j, v_i = weight of input i, n = amount of outputs, m = amount of inputs and K = number of units. Variable c_0 is added to the model to guarantee that the utility will be compared only with utilities of the same size i.e. it is an environmental variable. The index number 0 refers to the considered utility, whereas the index numbers 1,…, K refer to all other utilities. (Coelli et al. 1998, p. 150; Korhonen et al. 2000, pp. 126-127.)

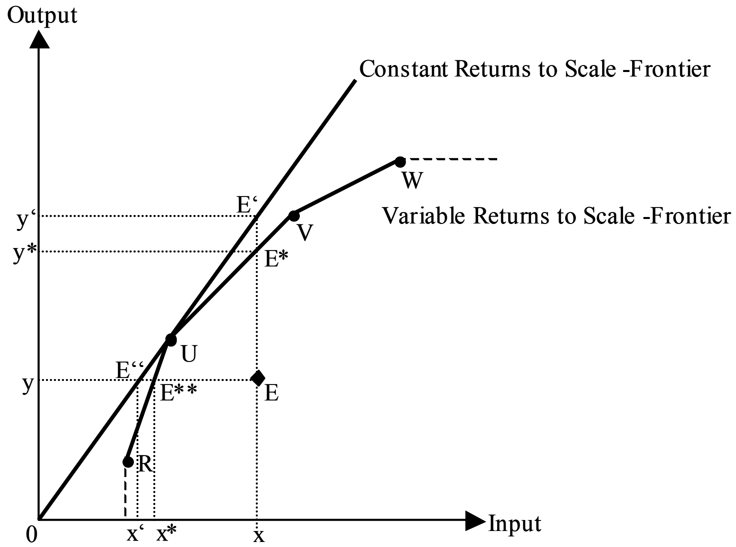

Figure 5.6: DEA -efficiency frontier in a case of scale economies.
(Source: Coelli et al. 1998, p. 152 ; Korhonen et al. 2000, p. 45.)

Figure 5.6 above shows a situation with constant and variable returns to scale. In this case, the problem is described with one output and one input. In Figure 5.6 both the constant and the variable returns to scale are presented: the straight line presents the case of constant returns to scale and the curve RUVW the case for variable returns scale. Measured with constant returns to scale, only firm U would be considered efficient. Its efficiency level would be the relation of the realised and efficient input, which is the same as the respective relation of the outputs. By taking the possibility of variable returns to scale into account, also the other firms except for firm E would be considered efficient. The efficiency of the firm E would be the relation of x'/x to y'/y in case of constant returns to scale and the relation of x*/x to y*/y in case of variable returns to scale. (Korhonen et al. 2000, p. 45.)

In efficiency considerations, the issue of economies of scale should be taken into account because in the electric they play a significant role. The model of variable returns to scale allows the regulator to take into account *scale efficiency*. In the model with constant returns to scale, it explains the size of the part of the inefficiency that depends on technical inefficiency and the size of the part that depends on scale disadvantage. The scale efficiency is the relation of the two efficiency figures. (Korhonen et al. 2000, p. 45.)

The advantages of the DEA method are listed by Charnes et al. (1994, p. 8). The DEA

- is based on individual observations instead of population averages.
- produces a single aggregate measure considering all chosen factors.
- can utilise multiple inputs and outputs even with different units of measurement.
- can adjust for exogenous variables.
- can incorporate categorical (dummy) variables.
- is value free and does not require information about a priori weights or prices of factors.
- places no restriction on the functional form of the production relationship.
- produces projection points for the desired levels of inputs or outputs.
- is Pareto-optimal.
- focuses on best-practice frontier instead of average tendency properties of frontiers.
- satisfies strict equity criteria in the relative evaluation of each utility. (See also Agrell and Bogetoft 2003, pp. 21-22.)

One of the practical problems of the DEA -method is that if the amount of the utilities is small the method does not generate reliable efficiency indicators. Zhang and Bartels (1998) have studied the effect of sample size on the mean efficiency. Their study shows that the sample size has a major impact on such comparisons. They found that as the sample size increases the estimated mean technical efficiency decreases. This means that when adding one extra utility the result for the remaining utilities does not get better, often it is even the other way around. The reason for this is that, if the 'old' utilities are more efficient than the 'new' utility, their relative efficiency does not change. If the 'old' utilities are less efficient, their relative efficiency will become lower, because the 'new' more efficient utility causes a shift in the frontier. Another character of this method is that when the amount of factors (output and input) rises the efficiency improves because there are more possibilities for the utilities to be relatively efficient in some respect.

Thus, the biggest problem is that the DEA is very sensitive for errors in the model specification. It cannot be determined with the help of the DEA, which factors are relevant. This means that the results of the DEA must be considered with care. It offers no possibilities for sensitivity analysis or testing the significance of differences in efficiency between the companies. In addition, the integrity of data determines the applicability of the DEA results.

Nevertheless, with the DEA it is relatively easy to identify the most efficient utilities in relation to their reference firms with similar structures. It is suitable for benchmarking of firms with many inputs and many outputs. It can also be further used to examine whether inefficiencies correlate with high prices or some other factors. Furthermore, the utilities cannot manipulate the method because the efficiency is delivered relative to other utilities. Thus, in the decision making process about whether to use the DEA or not, the advantages must be weighed against the disadvantages of the method with regard to the desired issue of study.

Agrell and Bogetoft (2003, p. 32) list several factors that can be the reasons for inefficiency:

- technical, scale or allocative inefficiency
- efficiency development of the industry
- excluded variables
- low capacity utilisation of investments

- non-accounted quality differences in outputs or inputs
- environmental characteristics like climate, local market or regulation
- uncertainty or measurement error.

A very useful characteristic of this method is that it creates projection points, so-called *peers* that are for example in

Figure 5.6 above the utilities R, U, V, W and Z i.e. the efficient utilities, as well as *target information* for each of the inefficient firms. The peers of inefficient firms are their benchmarks that have similar input-output mixes or a convex combination of them as the inefficient firm. The targets deliver information about the input and output quantities that the inefficient firm *should be able to achieve* if it were to operate at the efficient frontier. In this study, a multi-stage orientation of the DEA was chosen, which calculates the peers by conducting a sequence of radial movements to identify the appropriate projection point of an inefficient utility while the original input and output mixes are preserved as much as possible. (Coelli 1998, p. 3.)

5.4.2 Results of the Efficiency Study

5.4.2.1 Input and Output Factors

In the efficiency measurement, the 'sum of cost and return on capital' was used as an input (like described above in chapter 5.3.1) for the study of the cost efficiency and the 'volume of sales' as an input for the study of the price efficiency. There were two output factors. The one factor was the 'amount of distributed electricity per kilometer' reflecting the working load of the network, the other an indicator of quality, namely the 'uninterrupted time' per year[14].

The 'distributed electricity per kilometer' was considered for each tension level and summed up. In Sweden, there is data about the distributed electricity and the length of lines for low- and high-tension lines each. In Finland, this information was available for 0.4 kV, 6-70 kV and 110 kV networks. For Norway, such detailed information was not available at all. There, the distributed electricity was the total sum of electricity for all network levels together. It was tested with another efficiency study for Finland and Sweden, in which the 'distributed electricity per kilometer' was calculated like in Norway, all other factors ceteris paribus, whether the results are sensitive for this difference in the data basis. The results showed that there were non-significant differences in the efficiencies. Thus, it was considered that although 'distributed electricity per kilometer' was calculated slightly differently for the Norwegian utilities it does not have any significant implications to the results.

The uninterrupted time could not be directly applied in hours and therefore the interrupted time in h per year was inverted to deliver an *indicator* for the uninterrupted time[15]. Now, the longest interruption is noted with the smallest value meaning low quality; the shortest interruption time receives the highest value. Although the regressions in chapter 5.3.3 do not indicate that this factor is significant in explaining the cost, it was nevertheless decided to regard it in the

[14] The uninterrupted time could also be considered as an input, i.e. the interrupted time as a factor to be minimised. However, in this study, it was considered more unambiguous in respect of interpretation of the result that this factor was considered as an output and that there was only one input in the efficiency study.

[15] 1/interruption time in h per year = uninterrupted time. In case there was a value of zero as interruption time, the maximum value from the inverted sample was set as their value of output because division by zero is not possible.

efficiency consideration, because an indicator of quality was considered very important in the measurement of efficiency and because no other suitable indicators for quality could be found.

Equally important was to regard environmental factors so that the network utilities would be compared as much as possible with structurally similar utilities. The amount of customers and the ratio of cables to total amount of electric lines (‘cabling ratio’) were chosen as environmental factors because they were the ‘next best’ factors in explaining the cost and / or price (see Table 5.5 above). Like discussed above, the cabling ratio was used as an indicator of the structure of the service area. A high percentage of cables is considered to reflect a town-like agglomeration structure and a small percentage of cables reflects more rural areas. The environmental factors are technically treated as additional outputs, because they are continuous and non-categorical.

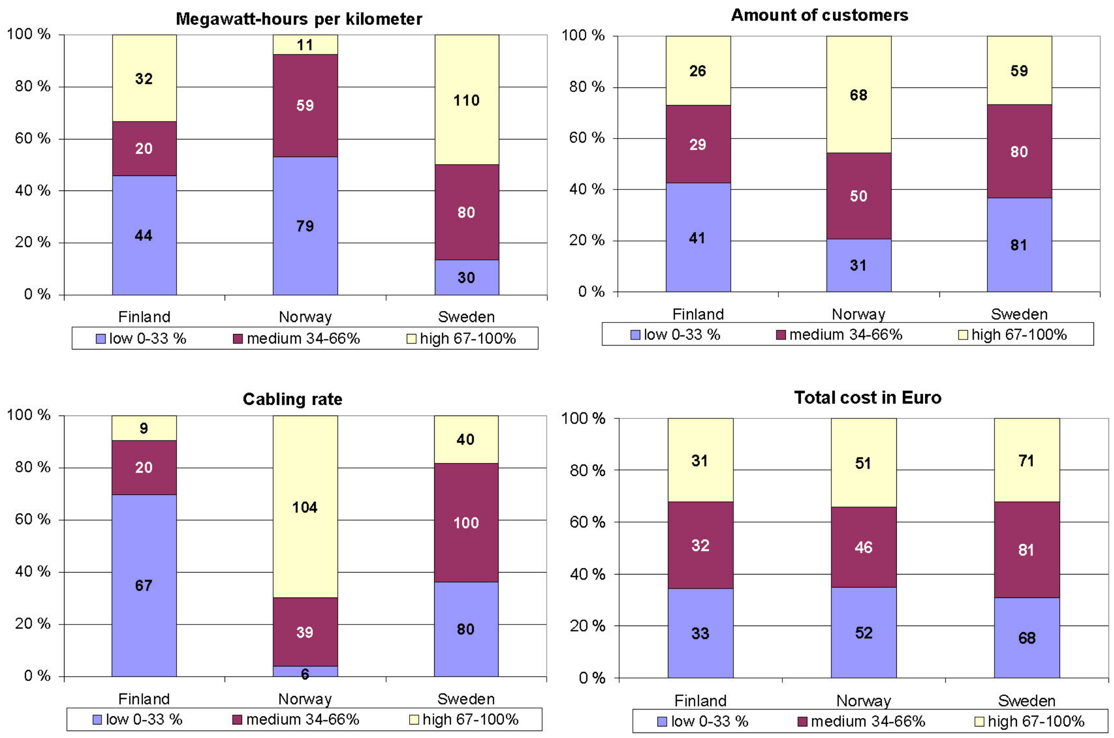

Figure 5.7: Structural differences of the distribution networks in 2000.
(Source: Own calculations.)

Figure 5.7 above shows structural differences between the three Nordic countries measured with the chosen factors. The pillars show how many percent of the network utilities from each country belong to the lowest/highest third of the total Nordic sample in respect of these factors. The amounts of utilities are displayed within the bars. This figure shows clearly that there are large structural differences between the countries that must be taken into account when considering pricing. Especially the structure in Norway often differs from the structure in the other two countries. Interesting is, however, that measured by cost, the distribution into the thirds is quite the same in all three countries.

5.4.2.2 Cost Efficiency

The cost efficiency measurement was done with a specific DEA-software DEAP Version 2.1.[16] There were four samples: three national samples for each country and one joint Nordic sample. The input-oriented efficiency measurement with an assumption of variable returns to scale shows quite similar weighted relative technical efficiency levels in Finland, Norway and Sweden measured with the national samples. The combined Nordic sample, however, shows a very different picture.

The joint Nordic sample has 465 utilities composed of the national samples, where the Finnish sample has 96, the Norwegian sample has 149 and the Swedish sample has 220 utilities. Due to the specific characteristic of this model, which was already discussed in chapter 5.4.1 above, adding an extra utility does not improve the efficiency of the ‘old’, already existing utilities. Thus, the average efficiency numbers for these countries in a total Nordic sample are not as good as the national efficiency results.

Table 5.7 below presents the weighted efficiency scores for the four samples. The first column shows the weighted mean efficiencies of the utilities calculated from the national samples. The second column shows the efficiency numbers that were calculated from the Nordic sample, in which information of all countries was put together. The efficiencies were calculated for three cases: the return on capital was set at six, ten and fifteen percent in order to make a sensitivity analysis about the influence of the capital basis on efficiency. There were no large differences in the average efficiency of the three countries. The efficiency numbers of the joint sample improved in Norway and in Sweden by some few percentage points when the capital return was increased whereas the relative efficiency of Finland slightly improved when the capital return was decreased. Thus, setting stricter constraints on capital return worsens the relative efficiency in Norway and Sweden. Taken together, the results are not very sensitive to the differences in capital return. Thus, a ten percent return on capital was taken as basis in this study so that the support of incentives to invest would not be undermined or ignored. (See Appendix C for the complete efficiency results and for the data tables.)

Distributed energy is used as weights for each utility to build a corrected average for the country. The efficiency score is between zero and one. Thus, efficiency score of 0.74 means, that the network utility is 74 percent efficient or, like in the table below, all utilities in this country on average.

16 DEAP version 2.1 (updated for Windows XP) was written by Tim Coelli (1996) at the Centre for Efficiency and Productivity Analysis, Department of Econometrics at the University of New England, Australia.

Table 5.7: Weighted efficiency scores for Finland, Norway and Sweden in 2000.

Weighted mean cost efficiency

capital return	*6%*		*10%*		*15%*	
	national	*Nordic*	*national*	*Nordic*	*national*	*Nordic*
Finland (n = 96)	0.76	0.74	0.74	0.73	0.76	0.73
Norway (n = 149)	0.76	0.36	0.75	0.36	0.75	0.39
Sweden (n = 220)	0.70	0.52	0.67	0.53	0.69	0.56
All (n = 465)	-	0.51	-	0.52	-	0.54

(Source: Own calculations.)

Although different samples cannot be directly compared with each other because the efficiency numbers are relative measures, it seems that countries reach rather similar cost efficiency scores when utilities are only compared with other national utilities. The efficiency scores do not differ greatly from country to country. In addition, the average technical efficiency is quite high when measured within a country at least in Finland and Norway. This result can be interpreted to mean that the regulation practices in these countries have succeeded in creating similar conditions for the network utilities within a country, which makes them reach similar efficiency levels on average.

Sweden, however, shows lower efficiency scores also when measured with the national sample. This result is supported by the efficiency study conducted by the SNEA in Sweden in 2002. The regulator realised that 177 of 241 network utilities are inefficient. The Swedish network utilities could save 1.6 billion crowns that equals 181 million euros within one year if all utilities would operate efficiently. According to the Swedish study, the long run efficiency improvement potential would be 26.5 percent per year of the used inputs and the short run efficiency improvement potential 20.2 percent per year. The utilities find this requirement quite unacceptable. The inefficiency of the Swedish electricity distribution could be a result of the uncertainty of the regulatory method because the Swedish regulatory authority has been searching for a suitable method for several years. Thus, the regulatory method has not yet delivered sufficient incentive for the utilities to improve their efficiency. (SNEA 2002b, pp. 30-31).

When analysing the Nordic countries together, the situation changes especially in case of Norway. In the Nordic sample, the weighted efficiency of Norway is only 36 percent. Finland's relative cost efficiency performance in the Nordic sample has changed the least compared with the national sample. The most efficient companies come from Finland and Sweden (see Figure 5.8 below). The utilities in Finland seem to be more sustainable in their efficiency than the Norwegian and Swedish utilities when measured with the chosen factors.

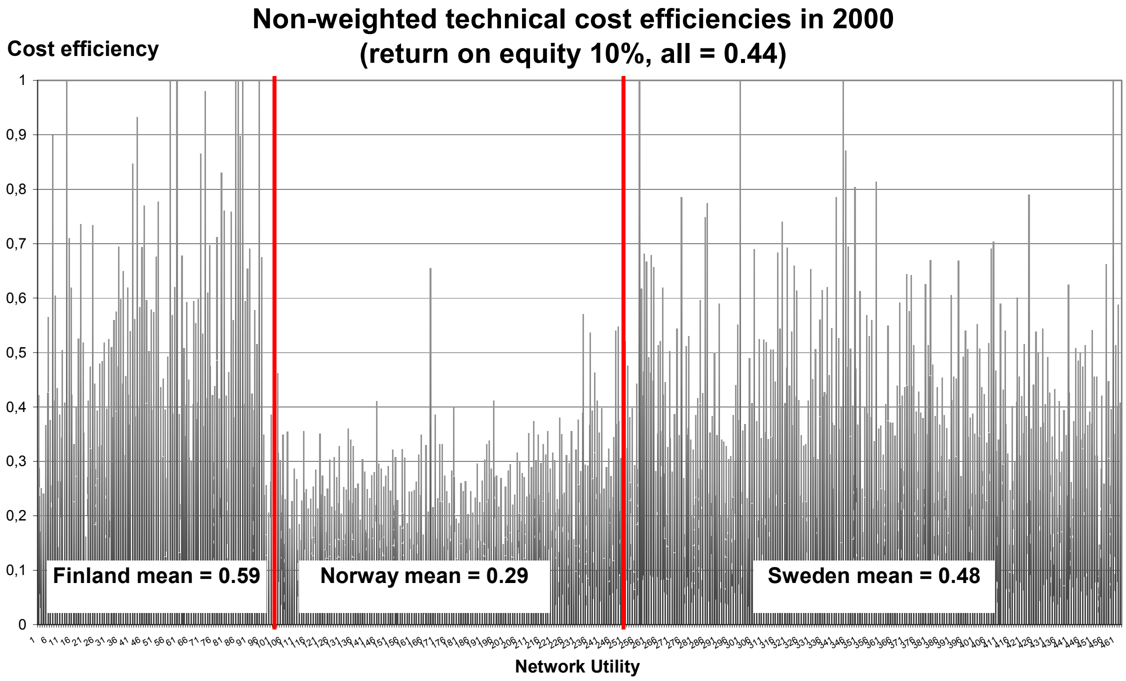

Figure 5.8: Cost efficiencies of the distribution network utilities.
(Source: Own calculations.)

The advantage of the DEAP is that it enables the determination of individual input targets for each utility. By reaching these inputs, the utility would be operating at the efficient frontier. Based on input targets, saving potentials for each company can be determined as the difference between the true cost of the company and the individual input target. Table 5.8 lists the sum of saving potentials based on the national and the Nordic samples. The input targets are corrected by additional ten per cent in order to avoid the detrimental effect of possible measurement errors. Summed up together, there could be potential for 1.0 -1.8 billion euros saving in these three countries per year.

Table 5.8: Saving potentials in euros in Finland, Norway and Sweden in 2000.

Cost saving potentials based on input targets (million Euros)

	national	*Nordic*	*difference*
Finland (n = 96)	183	209	26
Norway (n = 149)	290	807	517
Sweden (n = 220)	543	801	258
All (n = 465)	1016	1817	801

(Source: Own calculations.)

The differences in efficiencies within the total Nordic sample could be considered to reflect only the differences in the structural and other environmental factors of these countries. On the one hand, geographical conditions in Norway are indeed so much different from those in Finland and Sweden that it can be questioned with reason whether the environmental factors chosen here could adequately cover all of the differences. Another structural difference that prevails in the sector is that the regional networks distribute almost four times as much electricity in Norway than in the other countries. This could explain the smaller degree of utilisation of the distribution network if large consumers and industry are directly connected to the regional networks to a higher degree than in Finland and Sweden. In addition, Norwegian utilities are more capital intensive than the Finnish and the Swedish.

In such a case, that the differences in efficiency reflect differences in the environment only, the Table 5.9 below shows the value of these differences based on input targets delivered by the DEAP. According to the efficiency study, differing structures would cause an *extra cost* of 1.4 cent/kWh on average in the Nordic countries.

Table 5.9: Saving potentials in cent/kWh in Finland, Norway and Sweden in 2000.

Extra cost (=saving) based on input targets (in cent/kWh)

	national	*Nordic*	*difference*
Finland (n = 96)	0.68	1.01	0.34
Norway (n = 149)	0.75	1.91	1.16
Sweden (n = 220)	0.86	1.18	0.32
All (n = 465)	-	1.38	-

(Source: Own calculations.)

Nevertheless, on the other hand, the real advantage of the DEA method is that it compares only such utilities that are similar in their outputs and environmental factors. Thus, the differences also reflect the performance of the utilities and to some degree the success of the regulation method as well. Therefore, by improving their efficiency the utilities would be able to reduce their cost between 0.7 and 1.9 cent/kWh.

Table 5.9 above presents saving potentials in cent per kilowatt-hour. In Finland, this potential would be 1.0 cent/kWh, in Norway 1.9 cent/kWh and in Sweden 1.2 cent/kWh based on the Nordic sample. When the national potentials for saving are considered, the network utilities in Finland and in Norway could save 0.8 cent/kWh and the Swedish 0.9 cent/kWh on average. Efficient costs per kilowatt-hour are presented in Table 5.10 below. These numbers mean that with the present structure of output and environmental factors the utilities in Finland should be able to supply the distribution service at 1.5 cent/kWh cost on average in order to be efficient when comparing the total Nordic market. In Norway, the cost is even less: 0.8 cent/kWh on average. According to the national samples, the efficient costs lie between 2.0 cent/kWh in Norway and 1.4 cent/kWh in Sweden.

Table 5.10: Efficient cost on average based on input targets.

Efficient cost on average (in cent/kWh)

	real cost	*national*	*Nordic*
Finland (n = 96)	2.28	1.84	1.51
Norway (n = 149)	2.10	1.99	0.84
Sweden (n = 220)	2.11	1.44	1.12
All (n = 465)	2.14	-	1.11

(Source: Own calculations.)

A closer look to the peer companies of the Nordic sample shows that six of the peer (benchmark) utilities come from Finland and four utilities from Sweden. The technically efficient utilities function often at a larger scale, which can be seen from the comparison between the average outputs of the benchmark (peer) utilities and the average of the total sample. The outputs are in general higher among the benchmark utilities. None of the Nordic benchmark utilities exhibits *increasing* returns to scale (IRS). This is also the case for all peer utilities in national samples with only two exceptions in Finland. Therefore, it can be concluded that efficient utilities have tapped the full potential of scale improvements.

Scale efficiency is the relation of the efficiency measured by constant returns to scale and by variable returns to scale. The score for scale efficiency is also between zero and one because efficiency in case of constant returns to scale (CRS) is always smaller or equals to case with variable returns to scale (VRS). Thus, the smaller the difference between these efficiency numbers is, the higher is the scale efficiency. The results listed for the Nordic countries in Table 5.11 show that scale efficiency is high in all of the Nordic countries. This result means that large efficiency improvements cannot be realised through improving the scale of operations. Thus, the inefficiencies in these countries are not as much a result of scale disadvantage as a result of pure technical inefficiency.

Table 5.11: Scale efficiencies in Finland, Norway and Sweden in 2000.

Mean scale efficiencies (cost efficiency)

	national	*Nordic*
Finland (n = 96)	0.92	0.89
Norway (n = 149)	0.95	0.90
Sweden (n = 220)	0.92	0.89
All (n = 465)	-	0.89

(Source: Own calculations.)

Returns to scale seem to be quite crucial in the technical efficiency because within the utilities that have an efficiency of 0.7 and higher there are no utilities with IRS in the Nordic sample. In addition, when one considers the utilities with technical efficiency of 0.3 or less there are seven utilities functioning with IRS. In Norway and Sweden, the network utilities *all* function with decreasing returns to scale (DRS) based on the national samples. In the Finnish national sample, there is just one utility with low efficiency (≤ 0.3) and it operated at IRS. There are more utilities with DRS within utilities with high efficiency (≥ 0.7) than utilities with IRS. Thus, Finland is an exemption among these countries, because there some utilities operate at IRS.

Efficiency improvements, like listed in Table 5.9 cannot be expected from utilities within only one year. When setting three years as a reasonably long adaptation period the cost reduction (and hence also the price reduction) would be in Finland 0.2-0.3 cent/kWh, in Norway 0.2 – 0.6 cent/kWh and in Sweden 0.3 – 0.4 cent/kWh annually. Average prices corrected with the cost savings are presented in Table 5.12 below. The efficient price on average would be during the first year 2.1 - 2.3 cent/kWh based on the national samples and 1.8 – 2.2 cent/kWh based on the Nordic sample.

Table 5.12: Corrected prices on average for the first year in 2000.

Price - saving (three years adjustment) (cent/kWh)

	Price	*efficient price national*	*efficient price Nordic*
Finland (n = 96)	2.53	2.30	2.19
Norway (n = 149)	2.47	2.22	1.84
Sweden (n = 220)	2.39	2.11	2.00
All (n = 465)	2.45	-	1.99

(Source: Own calculations.)

Table 5.13 below presents the average profits of the network utilities in these countries based on the difference between cost and price in cent/kWh. In Finland and Sweden, the profit is approximately 0.25 cent/kWh and 0.28 cent/kWh, respectively, whereas the Norwegian average profit, 0.37 cent/kWh is somewhat higher. Based on this consideration, it can be concluded that in Finland and in Sweden the prices are closest to the costs.

Table 5.13: Average profit of the distribution network utilities in cent/kWh.

Profit on average cent/kWh

	cost	*price*	*profit*
Finland (n = 96)	2.28	2.53	0.25
Norway (n = 149)	2.10	2.48	0.38
Sweden (n = 220)	2.11	2.39	0.28
All (n = 465)	2.14	2.45	0.31

(Source: Own calculations.)

It should be remembered, like discussed in chapter 5.3.3, that companies may follow other priorities than cost efficiency. An important consideration is thus what the *opportunity cost* of efficiency improvement is. Is the money that can be saved through efficiency improvements more valuable when it reduces the electricity bill of the customers or would it be more useful when employed to reach other political targets? It is not acceptable that the efficiency improvements would take place through the reduction of the security of supply. In such cases where the utility follows other aims, it should however be able to proof its participation in such other activities. Nevertheless, for example political aims could be reached through other, more transparent ways (like through direct subsidies) without the incorporation of the local electricity distribution utilities to the local politics.

5.4.2.3 Efficiency of Pricing

Another possibility to make conclusions about the reasonableness of pricing is to study the volume of sales of the network utilities. The volume of sales includes information about the pricing of the company and covers all costs, including the return on capital, operational cost etc. It is an unambiguous indicator, because the firms' management cannot manipulate it, but still can influence it. The efficiency study of the volume of sales delivers direct information about the reasonableness of pricing. The efficiency study was executed with the same method and with the same outputs and environmental factors as the study of cost efficiency. The efficiencies are presented below in Table 5.14 and Figure 5.9. (See Appendix C for the complete efficiency results and for the data tables.)

Table 5.14: Weighted mean efficiencies of volume of sales in 2000.

Weighted mean price efficiency

	national	*Nordic*
Finland (n = 96)	0.78	0.77
Norway (n = 149)	0.80	0.44
Sweden (n = 220)	0.72	0.57
All (n = 465)	-	0.57

(Source: Own calculations.)

Utilities show slightly higher relative efficiency levels on average when measured with the volume of sales than with cost. This means that the differences between the companies are not as large i.e. their relative distance from the best practice frontier is not as far as when measured with cost. The efficiency numbers based on cost and volume of sales have a high positive correlation in all of the samples. The most cost efficient utilities are efficient also when measured as regards to volume of sales. Figure 5.9 below shows that the efficiencies follow the same pattern. The Norwegian utilities are clearly less efficient than the Finnish and Swedish also in this respect.

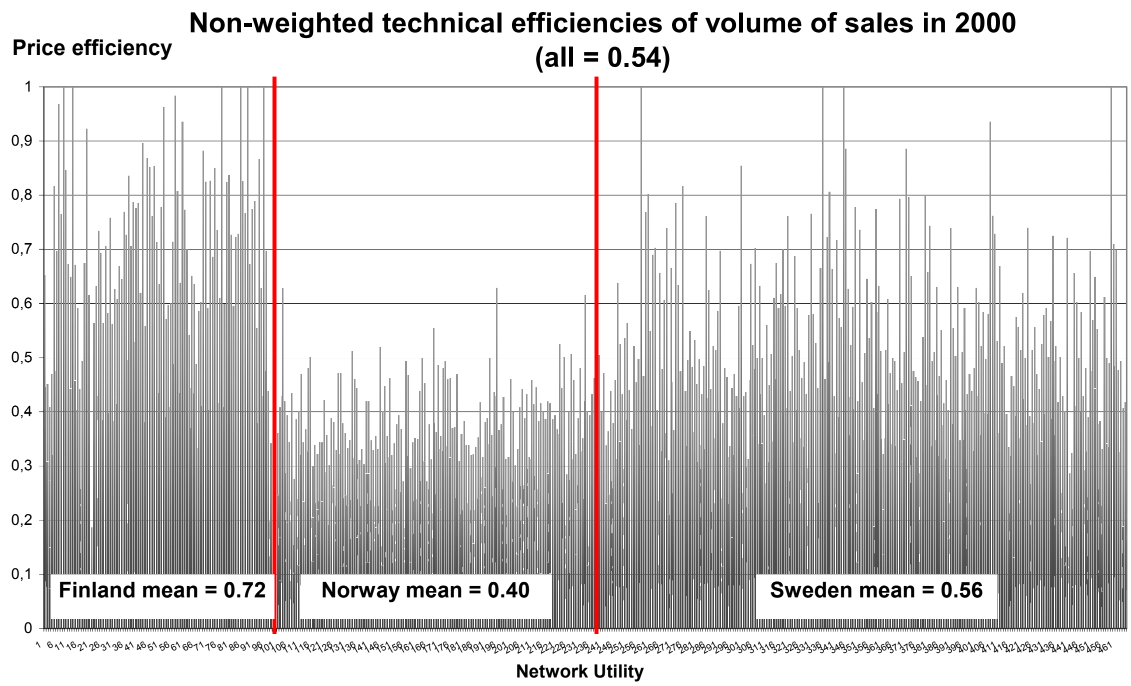

Figure 5.9: Efficiencies of the volume of sales in the Nordic countries.
(Source: Own calculations.)

As with cost efficiency, target values for savings as well as extra profits can be listed for each utility. The average values are shown in Table 5.15 and Table 5.16 below. There is a theoretical possibility of 842 - 1595 million euro saving through efficiency improvements, which is much less than through cost efficiency improvements.

Table 5.15: Potentials for saving in the volume of sales in 2000.

Saving potentials based on input targets (million Euros)

	national	*Nordic*	*difference*
Finland (n = 96)	162	170	8
Norway (n = 149)	202	657	455
Sweden (n = 220)	478	767	289
All (n = 465)	842	1595	753

(Source: Own calculations.)

Table 5.15 presents saving potentials that can also be interpreted as excessive profits in cent per kilowatt-hour. According to the efficiency study, the network utilities gain 0.5-1.4 cent per kilowatt-hour extra profit by not functioning efficiently. Thus, according to this, the electricity bills of the customers could be reduced by 0.5-0.6 cent/kWh in Finland, 0.5-1.4 cent/kWh in Norway and 0.8-1.0 cent/kWh in Sweden.

Table 5.16: Excessive profit of the network utilities in 2000.

Extra profit based on input targets (in cent/kWh)

	national	*Nordic*	*difference*
Finland (n = 96)	0.52	0.62	0.10
Norway (n = 149)	0.47	1.41	0.94
Sweden (n = 220)	0.76	0.97	0.21
All (n = 465)	-	1.04	-

(Source: Own calculations.)

The average price can be compared with the efficient price that can be ascertained based on input targets of the volume of sales of each network utility (see Table 5.17 below). It can be seen from the table that the network tariffs are still too high and the utilities gain monopoly rents compared to efficient prices. The efficient price is 1.9 – 2.0 cent/kWh in Finland, 1.1 – 2.0 cent/kWh in Norway and 1.4 – 1.6 cent/kWh in Sweden. When measured with the national sample, the largest difference of the actual price to the efficient price is in Sweden: 0.74 cent/kWh, although in Sweden the absolute price is the lowest. Finland and Norway both set prices circa 0.5 cent/kWh too high due to inefficiency. In order to reach these efficient prices within three years Finland should reduce its price 0.17-0.2 cent/kWh, Norway 0.16-0.47 cent/kWh and Sweden 0.25-0.32 cent/kWh yearly. This would lead to a price 2.0-2.4 cent/kWh in the first year. When compared with Table 5.12 it can be seen that this result is almost the same as when calculated with cost efficiency.

Table 5.17: Efficient prices of the distribution network utilities in 2000.

Efficient total price on average (in cent/kWh)

	Price	*national*	*Nordic*
Finland (n = 96)	2.53	2.00	1.90
Norway (n = 149)	2.48	2.00	1.07
Sweden (n = 220)	2.39	1.63	1.42
All (n = 465)	2.45	-	1.41

(Source: Own calculations.)

Also when measured with the volume of sales the scale efficiencies are very high based on all samples. This implies that the efficiencies measured by the constant returns to scale and variable returns to scale are very much the same. Utilities that have an efficiency score higher or equal to 0.9 do not exhibit increasing returns to scale. Table 5.18 lists the scale efficiency scores.

Table 5.18: Scale efficiencies based on efficiency of the volume of sales.

Mean scale efficiencies of volume of sales

	national	*Nordic*
Finland (n = 96)	0.96	0.98
Norway (n = 149)	0.88	0.99
Sweden (n = 220)	0.95	0.99
All (n = 465)	-	0.99

(Source: Own calculations.)

The studies show that the average cost and price are the highest in Finland although the cost efficiency as well as the efficiency of pricing is the highest. The efficiency studies thus verify that the cost level of the Finnish utilities is justifiable, because utilities with the same structure in Sweden and in Norway do not function with less cost. However, the very low efficient cost result in Norway can be questioned since it is possible that some factors that could not be considered have strong influences especially in Norway. Therefore, it is important to adjust policy based on individual considerations instead of average values.

5.5 Price Curves after Liberalisation

Figure 5.10 shows that all network prices today are lower than before the liberalisation in 1997. Especially after the first regulatory decision in February 1999, the prices decreased considerably for every customer class. This implies that the desired learning effect does take place among the network utilities. The decreasing trend was enforced by 7 percent reduction of the national network pricing in 2000-2001, which can be seen as a slightly accelerating decrease of prices from January 2000 because prices also include the prices of the overlaying networks. The sudden increase of the average prices in May 2001 can be explained by the price increase of one of the largest company in the sector. The prices reached their lowest values in June 2001. Another low was reached in October 2002 for many types of customers.

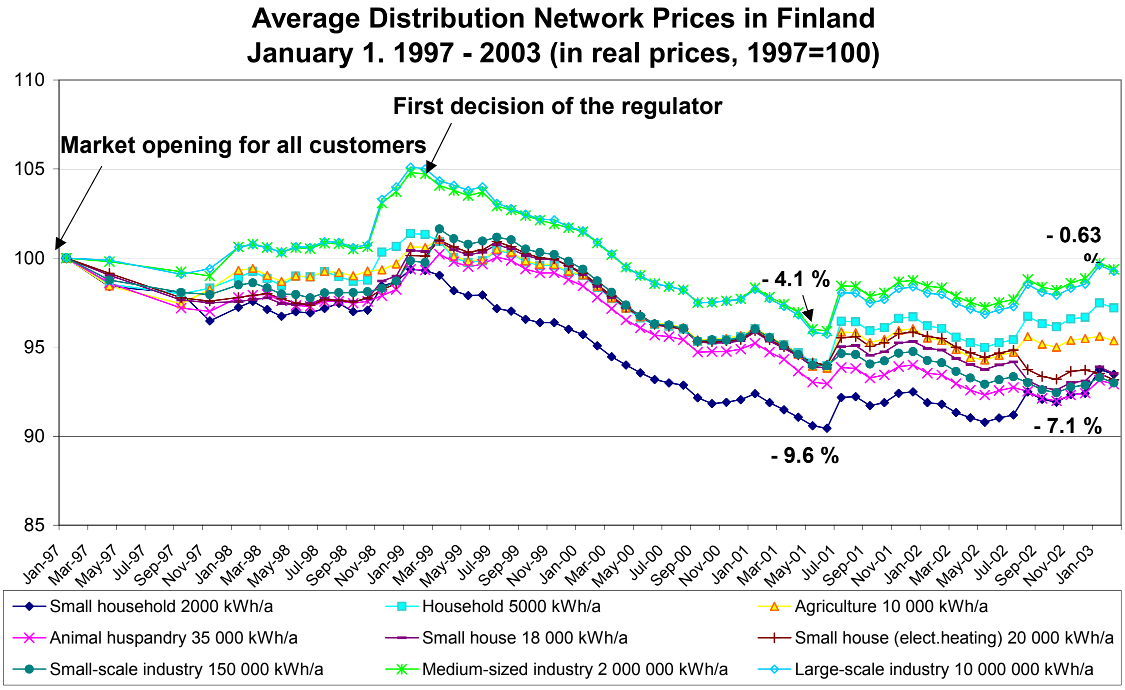

Figure 5.10: Distribution network pricing in Finland in 1997 - 2003.
(Based on: EMA (2003)[17].)

In Sweden, the impact of the regulatory policy is not as clear as in case of Finland. Figure 5.11 presents the Swedish network prices in 1998-2002. For households with yearly consumption of 20 MWh the real price has sunk by 2.5 percent in 1996-2002 and for the large industry by 4.6 percent in 1998-2002. For all other customer groups the prices are slightly higher than in 1998 (and for the other household groups higher than in 1996). Thus, the distribution prices have not systematically decreased after the liberalisation of the electricity market in Sweden. This, however, can be considered a success of the regulation, because at the beginning of regulation it was only required that the prices would not rise.

[17] The average prices for Finland in 2000 are calculated based on EMA's "keskihinta" -tables published for each month in the internet by EMA.

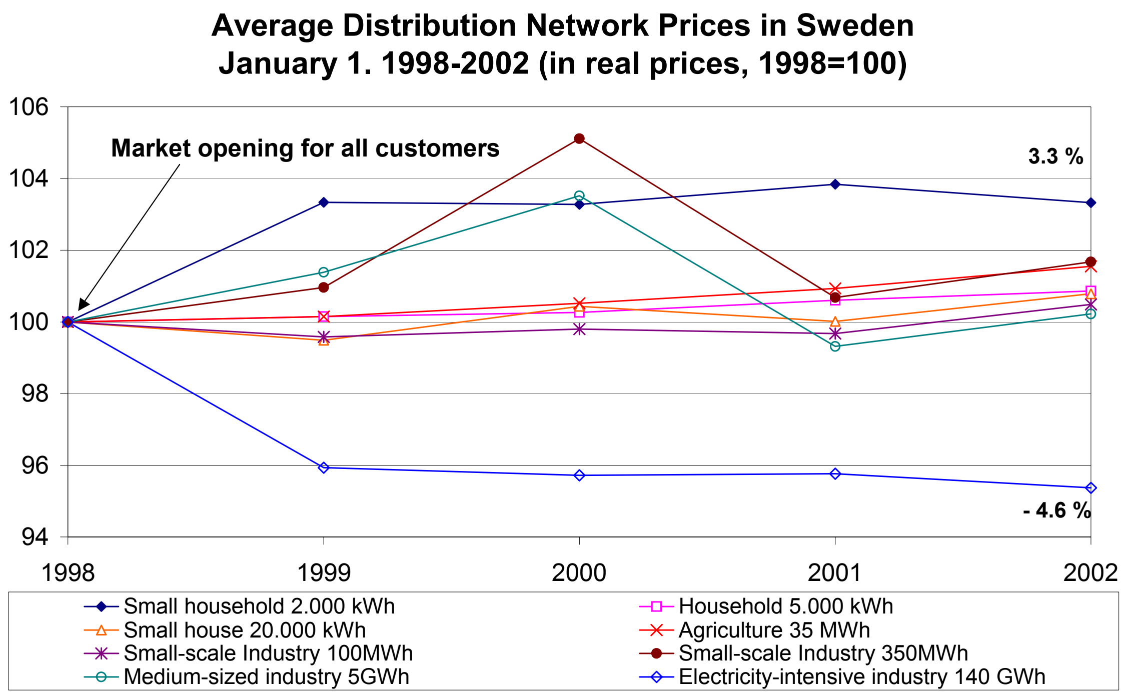

Figure 5.11: Distribution network pricing in Sweden in 1998-2002.
(Based on: SNEA (2002c)[18].)

In Norway, the electricity sector has been liberalised for the longest time. Figure 5.12 below introduces the price curve during the period 1993-2002. Real prices have sunk by 19.5 percent during this period for the medium large industry, at best even by almost 25 percent in 2001. However, prices for large-scale industry were at a higher level in 2002 than ever since 1994, for households and medium-scale industry higher than 1995 and 1996, respectively. This rapid increase could possibly reflect the new higher profit cap of 20 percent of the new regulatory scheme.

The influence of the regulatory scheme can be seen in this figure as a wave-like form of the price curve. In 1997, the new regulatory system was introduced and the prices rose. The prices started to sink towards the end of the regulatory period. Again, at the beginning of a new five-year period the prices rose again. This clearly shows how the utilities have incentives to adapt biased to the applied regulatory method.

[18] Prices for Sweden are set together from SNEA's internet price tables for households up to 20 MWh yearly demand, for enterprises up to 350 MWh/year and for enterprises up to 140 GWh/year.

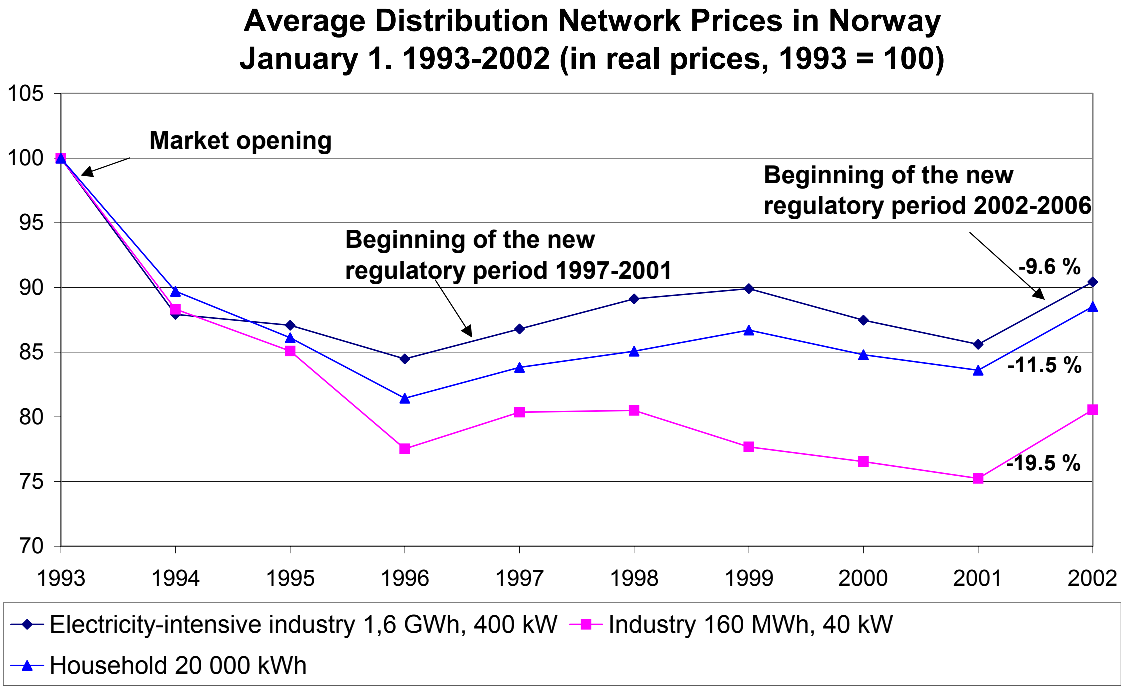

Figure 5.12: Distribution network tariffs in Norway 1993-2002.
(Source: NVE 2002a.)

This form of the price curve could be explained by the fact that, because the profit should not exceed the allowed maximum profit *on average* during the regulatory period, it is beneficial for the utility to gain higher profits at the beginning of the period, even higher than the allowed upper limit. This is because the money it receives today is more valuable to it than the money it receives tomorrow. This problem could be added to the discussion of the Norwegian regulatory scheme into chapter 4.5. See also the problems of the theoretical price / revenue cap method discussed in chapter 3.6.1.

5.6 Concluding Remarks

The aim of this chapter was to study the reasonableness of network pricing. The study was executed based on a study of the cost efficiency and the efficiency of pricing of the distribution network companies both for the countries separately (national samples) and for the countries together (the Nordic sample). In the efficiency study, an approach was chosen that takes into account different structural factors that influence the functional environment of the utilities. The efficiency was measured with an input-oriented data envelopment analysis (DEA).

Two ordinary least squares regression analyses show that the influence of the chosen environmental factors is in some cases statistically significant but that these factors explain only few percent of the cost or price. The factors that explain the cost the best are chosen in the efficiency study as outputs and environmental factors. The availability of information sets serious limits to the study of environmental differences because information e.g. about specific geographical structures in the service area of individual firms is not publicly available.

The efficiency studies based on cost and volume of sales as inputs, ‘megawatt-hours per kilometer’ and ‘the uninterrupted time’ as output as well as ‘the amount of customers’ and the ‘cabling ratio’ as environmental factors show that theoretically there are large possibilities for cost savings. Based on input targets that can be ascertained from the efficiency studies, the countries could theoretically save 775-1817 million euros through efficiency improvements. That would mean at minimum circa 0.7 cent/kWh and at maximum 1.9 cent/kWh reduction in the electricity bill of the customers on average based on cost efficiency. On the other hand, if one assumes that all utilities are principally functioning efficiently, the differences in input targets reflect the cost caused by differences in the operational and geographic environment of the individual distribution utilities. However, these theoretical efficiency improvement potentials should not be applied as such. Rather, they are indicators of the level of possible improvement possibilities.

The study further shows that there are large differences between countries in their efficiencies. The average relative cost efficiencies measured based on solely national samples greatly differ from the efficiencies measured with the joint Nordic sample. The non-weighted cost efficiency numbers are quite low measured with the Nordic sample as well as with the national samples, where the cost efficiencies do not quite even reach 60 percent. The weighted averages show higher cost efficiencies, which means that especially networks distributing small amount of electricity per year are less efficient possibly due to high fixed cost. The efficiency study with the volume of sales shows more or less the same picture. Hence, all possibilities for efficiency improvements are not yet fully exploited.

The performance of the Finnish distribution utilities seems to be the most efficient i.e. the efficiencies measured with the chosen factors appear to be quite sustainable. This would imply that the regulatory method chosen in Finland is at least not worse in improving efficiency since Finland shows higher cost efficiencies. These results speak for the ex post regulation.

However, like already shortly mentioned above, it is very important to notice that the efficiencies that are presented here, as well as the input targets delivered by the DEA-software, cannot be “taken literally”, because the efficiencies are relative. The different samples cannot be compared with each other directly and the efficiency scores are highly sensitive to the chosen factors. It is not possible to take all factors into account that might have an influence to the cost efficiency of the companies. This study mainly shows that there are large differences between the companies and countries and that there are potentials for efficiency improvements. The numbers presented here are rather indicative about the size and scale of the improvement potentials. In addition, the efficiency improvements suggested here could not be expected to be reached short term. The adjustment should be expected to take place gradually and should be considered individually. Like all empirical studies, also this suffers from imperfect empirical evidence that is subject to measurement and sampling errors. The weakness of empirical studies is also that they cannot be directly generalised.

In addition, the aims that one wants to reach through regulation must be kept in mind. The emphasis of regulation methods may differ and this naturally influences the chosen regulatory scheme as well as the success of regulation. Several different aspects of the regulatory policy can be found. These may be in conflict with or support each other. In this study, the emphasis is on the cost and price efficiency but the emphasis may also be on transparency, support of functioning markets or on design of a simple tariff structure etc. The regulator may also follow some other e.g. social or environmental goals that are difficult to ascertain in a study like this. In Finland and in Sweden, one aspect that has been considered important is the transparency of operations. Information relevant to this study was very easily available from these two countries via internet. Denmark had to be left out of the efficiency study because no information of the individual companies could be found without considerable effort.

The low efficiency results of Norway let one to assume that Norway might be a ‘victim’ of the method chosen in this study since obviously the Norwegian network utilities meet very different geographical challenges than the network utilities in the other two countries. In addition, there are differences in the regional and national networks between these countries that certainly play a role, but could not be considered. For example, the regional networks in Norway deliver four times more electricity than the regional networks in the other two countries. Moreover, there is clear evidence that the network utilities are obligated to co-operate with the municipalities in the realisation of the energy policy also under other preconditions than economic efficiency. From 1.1.2003, the utilities are obligated to participate in the design of socially rational future energy system (NVE 2002b). This aim can include the support of renewable energies, energy saving etc.

One reason for the lower performance of the Norwegian utilities is the fact that the capital cost of the Norwegian utilities is much higher than in the two other countries. This might be the result of the earlier rate-of-return regulation without any incentives to efficiency improvements, where the amount of return was based on the amount of capital inducing excessive investments to capital. Thus, this would be a classical example of an Averch-Johnson-effect described in chapter 0.

The price information about the development of pricing in Finland, Norway and Sweden shows that in Norway, where the liberalisation has the longest history, the network prices have sunk the most. Although in 2002, they are at a higher level than ever since the beginning of the liberalisation for two of the three considered types of customer. Nevertheless, the price curve lets one to assume that prices are set based on some strategic considerations. In Finland, the price curve shows a clear turning point after the first decision of the regulatory authority was verified in the supreme administrative court. Also in Finland, the prices are now at a lower level than at the beginning of liberalisation. In Sweden, this has not been the case. No general conclusions can be made based only on the price curve.

A comparison of the prices for the chosen types of customers shows that the average price level is quite similar between the similar types of customer in the countries studied. The variation of prices was the lowest in Finland based on prices 1.1.2001. In addition, the consideration of tariffs in different customer groups shows that the prices for households are higher than the ones for small-scale industry in the other countries except in Finland. One possible explanation for this exceptional lower price in the household sector could be in the structure of the electricity generation. Compared to Norway and Sweden, Finland has a lot of decentralised combined heat and power production, which might lead to a favourable cost structure in the household sector.

The tariffs in the network are set based on different components in these countries but they are all based on point-of-connection tariffs (see chapter 2.4.2). Pricing relies on a principle that prices are set based on costs. In each country, tariffs are formed from parts that often differ from that of the neighbour. Usually, however, there is a fixed fee of the tariff and a fee based on the physical power flow demanded or supplied (see chapter 0 for two-part tariffs). The utilities weigh the shares of the different parts of the tariff differently and the trend of development differs between the countries. In Sweden, the trend is towards setting prices for households based only on fixed charges, whereas in Finland this practice is considered unfair against the users demanding a small amount of electricity. The average prices of the households might reflect the influence of the pricing practice contributing to lower average household prices in Finland and higher in Sweden. In Norway the prices for the large-scale industry are less than one cent per kWh.

In the Norwegian and the Swedish transmission networks, there is congestion between the south and the north. Therefore, some parts of the country have higher cost and thus utilities must pay higher prices to the overlying networks. Congestion in the transmission networks can thus be one reason for the higher cost of the utilities compared with utilities with similar structure in Finland and therefore a reason for resulting lower efficiency scores. Hence, the problem might be the general inefficiency of the existing transmission and generation infrastructure. In the long-term, the infrastructure of the electricity supply can be changed into being more favourable but the main structure will certainly remain as it is today: northern generation and southern consumption.

Besides of investing into transmission lines in order to avoid capacity bottlenecks, another possibility is to increase the amount of decentralised and small-scale energy production in an area with excess demand, which might help to reduce the congestion. It might also decrease the cost of transmission losses, because generation is closer to consumption. In the short-run, such changes cannot be expected and therefore the importance of regulation in inducing incentives to upgrade and manage the network cannot be overestimated. Therefore, the two - partly conflicting - aims should be combined in the regulatory scheme: cost efficiency and incentives for the utilities to manage a good quality network.

6 SUMMARY AND CONCLUSIONS

The Nordic countries have a long experience in the liberalisation of the electricity sector. The market opening is based on regulated third-party access. In each country, a specific regulatory authority supervises the monopoly part of the sector. Several theoretical regulation theories address the issue of preventing monopoly rents and/or inducing efficiency improvements. The purpose of regulation is to create conditions similar to competition in such part of the market where full competition fails. Regulation is thus introduced to secure public interest. This usually means the attempt to exclude prices that would significantly exceed those of the competitive industry.

The main problems of regulation are related to asymmetric information. If all market actors had full information, there would be no problems, but since the utilities always know more about their true situation than the regulator, the choice of an appropriate regulation method poses a problem. The deficiency of information and the resources available to regulator in respect of the amount of utilities influence the design of the regulatory method. Another problem, besides asymmetric information, is inefficiency and thus different regulation methods can be classified based on their approach to efficiency improvements. When evaluating efficiency, the regulator has to keep in mind that the firms differ in size, structure and ownership.

In practice, creating competition into the monopolistic market without cost is impossible. All regulation theories face limitations in their practical implementation. There is no 'right model' and that is why the models must be adjusted to the real-life situations. Establishing a regulatory scheme is often a matter of bargain between the differing interests of several parties. The final regulatory system is often a compromise between the interests of the network utilities and the regulator.

A frequently discussed incentive regulation method is yardstick competition. It reduces the problem of asymmetric information through forming a benchmark. The regulator compares all utilities in the sector and determines the kind of performance the utility should be able to produce. This method creates an incentive to cost reductions and efficiency improvements because the utility gains when it improves its performance when the other utilities in the market do not.

Principally regulation aims at creating prices that are non-discriminating and fair, to some degree cost oriented (they should cover the efficient cost of the network activity), have a signaling and steering function and are practical, simple and transparent. Once the model is chosen, it should not be subject to short run changes in the regulatory policy, which means that the regime should be sustainable regardless whether it is based on structural or price regulation or whether its focus is on preventing profit or creating an incentive to cost reductions.

A look at the electricity prices in the Nordic countries reveals that the liberalisation has been a success. The trade margins of electricity prices have shrunk and the prices for electricity sunk reflecting the spot prices, which means that the monopolistic bottlenecks have not hindered the development of competition in the competitive part of the sector. This also means that regulation has been successful in reducing monopoly power in the market. In all of the Nordic countries, the electricity network regulatory schemes address the efficiency problem although the schemes differ between countries. For example, Finland and Sweden apply ex post regulation whereas Denmark and Norway rely on ex ante systems. This study describes the regulatory systems in these countries considering their advantages and disadvantages.

The advantage of a regulated third party access compared to the negotiated third party access, where the market access is based on bilateral agreements between market actors, is that all actors in the market face same conditions. This creates transparency in the market contributing to reduced monopoly power and to non-discriminating prices. Still, all regulatory methods have some advantages and shortcomings. No method is perfect, because it is impossible to design a manageable method considering all factors that influence the operational environment of the network utilities.

All regulators in the Nordic countries strive for efficiency improvements. The regulatory authorities in Finland and Norway evaluate the performance of an network utility by comparing it with other firms in the sector by forming a benchmark. The advantage of this approach is that the companies do not benefit by reporting their cost falsely because the result of regulation depends also on the performance of all other firms in the sector. Thus, the problem of asymmetric information can be reduced.

Finland and Sweden base their regulation schemes on ex post price supervision i.e. the reasonableness of pricing is reviewed after the price-setting period. This approach is considered lighter in realisation and more flexible than the ex ante schemes. The decisions are made individually for the affected utilities and thus these systems rely much on the learning effect of other companies in the sector, which is their weakness if it does not take place. Nevertheless, the learning effect is considered to take place easily because the regulation method is transparent and simple, which indeed can be verified when looking at the price curve of the Finnish distribution utilities after the first regulatory decision was verified in the supreme administrative court. The ex ante regulation is slower mainly because the regulatory period often lasts for several years. Ex post supervision requires a high degree of transparency in pricing.

The ability of the Danish system to measure efficiency can be criticized because it does not measure the efficiency of the use of capital at all. It also does not take into consideration any differences in the quality of electricity or in the general operational environment. The method used in Norway has weaknesses because the benefits received from the efficiency improvements go mainly to the owners of the companies, not to the customers. The possible 20 percent return on invested capital is rather high for low risk monopoly actions. The development of the consumer price index and the increase of distributed electricity might exceed the efficiency requirement, which would fully offset it. The Norwegian system is slow in realizing efficiency improvements i.e. because the revenue caps for the period 2002-2006 are based on historical costs from 1996-1999. Thus, the system is partly based on six years old information.

Ex post systems, like those in Finland and Sweden, are sometimes criticised because it is thought that companies are studied only based on complaints from customers, which is considered unfair. According to this critique, complaints will be most likely issued of companies that have high prices although the prices might be altogether justifiable based on firm-specific situation. Thus, according to this view the ex post systems do not treat all companies equally. This argument can be questioned since for example in the case of Sweden the firms that lay further from the cost curve are examined more closely from the initiative of the regulatory authority. In Finland also, the regulator initiates supervisory processes on its own partly based on efficiency numbers not only based on complaints. The companies are treated fairly and equally because all companies are aware of the regulatory rules, thus, the system is transparent.

The strength of the Swedish fictive network method is that it delivers objective measures for technical efficiency, according to which the network utilities orient themselves in their practical real life decision-making. Nevertheless, the efficiency improvement practice is a long run process, which delivers a measure for technical efficiency based on the difference between the true network construction and the technically possible structure. Special problems are e.g. how to measure the cost of interruption for different customers and how to build the quality surplus that treats all utilities equally irrespective of the structure of customers. The lack of the Swedish fictive network method is that it does not take into account the historical development of firms' structures, which mostly explain firms' cost and capital structure today. A further disadvantage of this method is the lack of consideration of any factors set by geography or other environmental factors.

An advantage of this model is that it is unambiguous and it is difficult to manipulate by the companies. Therefore, the problem of asymmetric information can be reduced. In addition, this method is manageable from the regulatory point of view and creates transparency within the system.

The Finnish electricity market legislation allows the regulator to design quite freely the regulatory system. The expression 'reasonable pricing' used in the legislation leaves a lot of room for interpretations. The Finnish system requires a certain level of activity from the supervisor's part and a short processing time for appeals about distribution prices that do *not* seem to be *un*reasonable. Setting rules in the markets is difficult and slow in respect of the needs of the market, which can be considered a weakness of the system. Starting an appealing process might prolong the time span during which the firm can continue its unreasonable pricing policy, because the decision of the supervisor is not binding until the appealing process is finished. The regulatory decision is valid only for an individual firm and cannot be directly generalized. If other firms will not learn from this process, it means a large workload for the supervisor.

Nevertheless, the regulatory authority in Finland considers the low regulatory effort as one of the main advantages of the applied scheme. Therefore, the system can be considered flexible and light and the regulatory organisation remains flat. Only those firms that are suspected of unlawfulness are investigated in more detail. Due to the large amount of firms operating in the sector, it is considered that an ex ante approval method would increase the workload of the supervisor substantially. The individual firms have in any case the best information for forming their own tariffs. It can be expected that they are aware of the criteria on which the reasonable pricing is based and therefore most of the firms choose the right price levels independently because they wish to avoid the investigation process e.g. because the investigations can be made retrospective also after several years.

The price curve of the distribution network prices shows that after the liberalisation of the electricity market in Finland the real distribution network prices have decreased for all types of customers. After the first regulatory decision in Finland in February 1999, the prices started to decrease. This indicates that the desired learning effect does take place among the network utilities.

In Sweden, the impact of liberalisation is not as clear as in case of Finland. There, the average price curve shows that the prices have remained quite stable for most of the customer types. At 2002, only the prices for electricity intensive industry were lower than in 1998 by 4.6 percent. The regulation method in Sweden has thus not induced sufficient incentives for price reductions.

In Norway, the electricity sector has been liberalised for the longest time. This can be seen as a better result for the three customer groups studied. Nevertheless, in 2002, prices were at a higher level than ever since 1996. For households and large-scale industry, they are even higher than in 1995 and in 1994, respectively. This increase could reflect the profit cap of 20 percent of the new regulatory scheme. The influence of the regulatory period on pricing can be seen as a wave-like form of the cost curve. In year 1997, the new regulatory system was introduced and the prices rose. Towards the end of the regulatory period, the prices started to sink. Again, at the beginning of a new five-year period the prices rose. This price curve thus reflects the utilities incentives to strategic behaviour in order to maximise their profit. The utilities profit should not exceed the allowed maximum profit *on average* during the regulatory period. Therefore, it is beneficial for the utility to get higher profits at the beginning of the period - even higher than the allowed upper limit - because the money it receives today is more valuable to it than the money it receives tomorrow. This could explain the form of price curve.

Efficiency measurement in Finland, Norway and Sweden was executed with a specific DEA-software DEAP. The efficiency measurements were based on an input-oriented approach with an assumption of variable returns on scale. Efficiency scores were determined based on selected physical information as well as cost and price information of each distribution network utilities. ‘The distributed electricity per the length of electric lines’ was used as an output parameter, ‘the amount of customers’ and ‘the cabling ratio’ as a factor describing the environment, ‘average interruption time per year’ as a quality factor. These factors were chosen based on an ordinary least squares regression analysis, which revealed that only some of the environmental factors were significant in explaining cost or price. The coefficients of determination were also very small, which means that these factors explain only few percent of the cost and therefore their influence is possibly overestimated.

In the first efficiency sample, the cost plus the return on equity, and in the second, the volume of sales were used as inputs. The results from both of these efficiency studies were similar. The efficiencies for each country were determined based on national samples and second on a joint Nordic sample.

One characteristic of the DEA-method is that when adding one extra utility the result for the remaining utilities does not get better, often it is even the opposite. The reason for this is that, if the ‘old’ companies are more efficient than the new company is, their relative efficiency does not change, but if they are less efficient, their relative efficiency will be smaller due to a shift of the efficiency frontier. Thus, the average efficiency numbers in a joint Nordic sample are not as good as the national efficiency results.

The different samples cannot be directly compared with each other but it appears that companies within a country seem to be rather similar in their efficiencies measured both with the cost as well as with the volume of sales. This could mean that regulation practices in these countries have succeeded in creating similar conditions for the network utilities within a country, which makes them reach similar efficiency levels on average. However, when comparing with the neighbouring countries the situation changes, which is especially the case in Norway. In the Nordic sample, the weighted cost efficiency of Norway is only 36 percent. Finland's relative efficiency performance in the Nordic sample has reduced the least compared with the national sample. This could indicate that the efficiency level measured with the chosen factors is quite sustainable in Finland also when compared with other countries. The most efficient companies come mainly from Finland.

The differences in efficiency within the total Nordic sample could be considered to reflect only the differences in the geographical and other environmental factors of these countries. On the one hand, geographical conditions in Norway are indeed so much different from those in Finland and Sweden that it can be questioned with reason whether these environmental factors could adequately cover all differences. As shown in the regressions, the coefficients of determination are low. In such case that the differences in efficiency are only caused by differing structures, an extra cost of 1.38 cent/kWh on average would be a result of deviating structural characteristics according to the cost efficiency based on the joint Nordic sample.

However, on the other hand, the true advantage of the DEA method is that it compares only such utilities that are similar in their outputs and environmental factors. Thus, to some degree, the differences do reflect the performance of the utilities. This would imply that the ex post methods might be somewhat superior in improving efficiency since here the ex post regulated countries show higher cost efficiencies than the one example of an ex ante regulated country.

Based on the input targets it can be ascertained the height of the theoretical cost savings in the sector. Considered together there could be theoretical potential for 775-1817 million euros saving in these three countries (i.e. on the electricity bill of 9.6 million people) if the utilities operated efficiently. The difference between the cost and price i.e. the profit in Finland in 2000 was on average 0.25 cent/kWh, in Sweden 0.28 cent/kWh and in Norway 0.38 cent/kWh. Thus, this indicates that the income frame system in Norway has not been as efficient in reducing monopoly rents as the ex post systems in Finland and Sweden.

The Finnish regulatory scheme seems to have induced a learning effect, which can be seen as the steady decrease of the average price curve after the beginning of the liberalisation. The price curve in Norway shows a form that suggests that the utilities set their prices based on strategic considerations that are in conflict with public interest and with the purpose of regulation. The performance of the Finnish distribution utilities seems to be the most efficient. However, geographical and other environmental factors should be taken into account more when comparing between countries. This is - unfortunately - difficult, because such information is not publicly available for single network utilities.

A closer look at the average cost shows that the cost is highest in Finland. This result is not in conflict with the efficiency study, according to which Finland appears to be most efficient. The reason is that structurally similar utilities in the other countries do not manage to produce with lower cost either, and therefore the Finnish average cost and price are altogether justifiable. The problem of the Norwegian and Swedish electricity distribution industries might lie on the generation infrastructure and on the existence of limits in the transmission capacity. Congestion in lines causes areas with higher cost, which thus hinders the development of competition in the downstream market. Because utilities in Norway are vertically integrated, the network utilities might not even have the incentives to remove the bottlenecks of their networks, because these enable that the generation utilities can exert market power.

However, the availability and the quality of data pose serious limits to the study and to the interpretation of the results. There are also great structural differences in the geography between and within the countries and therefore the question remains, whether the structural characteristics studied here can adequately cover the different requirements the utilities are confronted within their operational environment.

In my view, the application of efficiency improvement requirements in the regulatory scheme is desirable and should be developed further. Irrespective of the weaknesses of the benchmarking methods, it is my opinion that these methods lead to a better regulation result than without benchmarking. Like Agrell and Bogetoft (2002, p. 33) state, the problem of asymmetric information in the regulatory practice can be avoided if information is not directly used against the utility. Even incomplete models may be useful in the inducement of favourable market conditions. The advantage of the DEA-method used in the regulation practice in Finland and Norway is that it enables the regulator to put pressure on inefficient firms because it can provide the firms concrete targets and peers.

It seems that merely the existence of an established, clear regulation leads to better efficiencies, which can be seen by comparing the efficiencies of the national samples in Finland and Norway with the national results in Sweden. Thus, I consider a clearly defined and stable regulation of the distribution monopolies recommendable irrespective whether it is based on ex post or ex ante regulation. Equally important is that the regulatory authority is independent of the industry so that there is a credible thread of punishment of monopoly behaviour and inefficiency in order to induce efficiency improvements and to reduce opportunistic behaviour.

This study implies that in the case of Nordic countries the ex post regulation system in Finland has been rather successful, whereas in Norway the utilities are able to set their prices based on opportunistic strategic behaviour that might be in conflict with the public interest. Thus, based on this study an ex post regulation could be recommended. Nevertheless, this study is subject to uncertainties like all empirical studies. The decision about whether to apply ex ante or ex post approach depends on the local situation and on the applied method with its special characteristics. The national legislation also sets limits on how much freedom and resources the regulator has in its disposal when deciding about the regulatory scheme. The success of ex post methods also depends on the degree of co-operation of the utilities.

However, establishing operative efficiency in the market is not a sufficient condition for the design of suitable regulation scheme supporting long-term development of the electricity distribution sector. Other important issues are the guaranteeing of an optimal rent that is neither too high nor too low as well as inducing optimal investment incentives to develop and manage the distribution infrastructure.

In the past, electricity networks were constructed based mainly on the peak load only. It was thought of that cheap energy is available unlimitedly. Nowadays, it has been finally realised, that the use of fossil fuels is not cheap due to very high external cost. Therefore, in the future, the challenges of networks are the decentralised energy sources, which mean as a rule renewable energies. The increasing amounts of decentralised and renewable energies injected into the networks induce higher requirements for the stability of the networks. The problem of for example wind energy is the fluctuating injection and unpredictability of the availability of the wind resource. Therefore, these energies need reserve capacities as backups, but, from the social point of view, it is not desirable that large reserve capacities must be build. Therefore, the transfer services are crucial for the development of decentralised and renewable energies.

On the other hand, the increased amount of decentralised production reduces the need of long distance transfer of electricity. This might help also to reduce the cost of local distribution utilities for example through reduced network losses and reduced congestion in the transmission lines. In Norway and Sweden, the amount of decentralised and renewable, non-adjustable energies is very low at present. Therefore, these issues have not really played a role up until today.

However, due to the increased networking of these areas with the Central European UCPTE through Denmark, where there is a lot of wind energy generation, this situation is about to change in the future. It might also ease the problem of congestion of the transmission networks in Norway and in Sweden, if new decentralised generation capacity were build in southern parts of these two countries. This might lead to cost savings and improved efficiency of the existing infrastructure. In some cases, the need of large investments into network capacity could be possibly avoided. On the other hand, the climate change presumably increases the frequency of extreme weather occurrences, which is unfavourable for networks with high amount of overhead lines. It is possible that these developments induce higher need for replacement investments, where overhead lines are replaced with cables as the case of Denmark showed.

The question for the future is how can benchmarking take into account the new developments in the electricity markets. In the future, also energy saving becomes more and more important and therefore the benchmarking methods are set to answer a new question about how to promote energy savings even though it means a decline in the revenue of utilities or should higher prices be allowed. In the long-term, if regimes are successful, the performance of the utilities will converge gradually towards efficiency. Then, the incentives of the utilities to consider efficiency decrease. Thus, the question of the regulators is what comes after benchmarking.

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APPENDICES

Appendix A

The model of Laffont and Tirole (1993, pp.168-171) is presented as a situation where the task of the regulator is to create an optimal regulation policy for a multiproduct firm. The regulator is able to observe the firms costs and quantities produced. Laffont and Tirole choose an aggregate cost function $C = (\beta, e, q_i)$, where the type of the firm is defined by its technological parameter β ($C_\beta > 0$). The regulator does not have information about this parameter but supposes that β is between $[\underline{\beta}, \overline{\beta}]$ and has the cumulative distribution of $F(\beta)$ with density function $f(\cdot)$. e is the managers effort to reduce costs ($C_e < 0$) and $q_i \equiv (q_1,...,q_n)$ is the firm's output vector ($C_{qk} > 0$). The cost function of the firm depends therefore on its technological parameter β and on its effort e, which are, however, unknown to the regulator.

$E(\beta,C,q_i)$ is chosen to denote the effort required for a firm of type β to produce q_i at cost C (effort function):

(A 1) $$C \equiv C(\beta, E(\beta, C, q_i), q_i).$$

$E_\beta > 0$, $E_C < 0$ and $E_{qk} > 0$ are the partial derivatives of the effort function with respect to its arguments. In this model, the state receives all the revenue from the sales and the firm receives a transfer from the regulator in the height of t as a repay to cover its costs. If the firm makes an effort it will cause costs of $\psi\ (e)$ i.e. ψ is the disutility of effort. The firm's objective function is therefore

(A 2) $$U = t - \psi(e) \qquad \textit{(incentive constraint)}$$

and the firm accepts only $U \geq 0$ meaning that the firms utility has to be positive for the firm to participate in the regulatory process. $V(q_i)$ denotes the well-behaving social value function for the production of output vector q_i.

The social value $V(q_i)$ in this model is formed from the *gross* consumer surplus $S(q_i)$ less $R(q_i)$, which is the monopolists revenue from the production, i.e. the *net* consumer surplus and from the social value of the tax savings for taxpayers, which is generated by the sale of the goods *i*, $(1+\lambda)R(q_i)$. λ presents the shadow costs of the public funds. Therefore $V(q_i) = S(q_i) + \lambda R(q_i)$.

The utilitarian social welfare function is a sum of consumer surplus and the producer surplus:

(A 3) $$W(q_i) = [V(q_i) - (1+\lambda)(t + C(\beta, e, q_i)] + U \quad ,$$

or using equation ((A 2),

(A 4) $$W(q_i) = V(q_i) - (1+\lambda)(\psi(e) + C(\beta, e, q_i)) - \lambda U$$

The equation (A 4) shows that the welfare is composed from the social value of outputs, the total cost of operating the firm multiplied by its shadow price and the social cost λU of allowing the firm a rent.

Solution with full information

The maximisation problem of expectations over β of the social welfare function is presented in equation:

(A 5) $$Max\, E_{\beta}W = \int_{\underline{\beta}}^{\overline{\beta}}\left[V(q) - (1+\lambda)(\psi(e) + C(\beta, e, q_i)) - \lambda U\right] f(\beta) d\beta$$

subject to the incentive constraint and individual rationality constraint $U(\overline{\beta}) = 0$ meaning that no type of firms is allowed to make losses, but also that the regulator does not want to allow the firms any rent. *f(β)* is the probability that the firm has type *β*. The derivative of *β* of the effort function of the firm is $de = E_{\beta}(\beta, C(\beta, e, q_i)q_i)d\beta$. Then the gradient of the firms rent considering *de* is:

(A 6) $$\dot{U}(\beta) \equiv dU / d\beta = -\psi'(e) de / d\beta = -\psi'(e) E_{\beta}(\beta, C(\beta, e, q_i) q_i).$$

Equation ((A 6) is the first order condition of incentive compatibility for the firm (equation ((A 1), which means that the firm cannot reach a better outcome by choosing another type than its true type. Laffont and Tirole (1993, p. 170) have interpreted the equation as a rate at which the firm's rent should grow to be able to elicit its information.

The regulator maximises equation (A 1) subject to the individual rationality constraint $U(\overline{\beta}) = 0$ and equation (A 6), where *e(β)* and $q_i(\beta)$ are the control variables and *U(β)* a state variable. The first-order conditions of the maximisation problem with respect to effort *e* and output q_k are

(A 7) $$\psi'(e) = -C_e - \frac{\lambda}{1+\lambda}\frac{F(\beta)}{f(\beta)}\left[\psi''(e)E_{\beta} + \psi'(e)E_{\beta C}C_e\right]$$

(A 8) $$V_{qk} = (1+\lambda)C_{qk} + \lambda\frac{F(\beta)}{f(\beta)}\psi'(e)\frac{d}{dq_k}(E_{\beta}).$$

In a first best world in a situation with symmetric information, the marginal disutility of effort $\psi'(e)$ should equal the marginal cost savings $-C_e$. *F(β)* presents the possibility that the firm is more efficient than type *β* and *f(β)* the possibility that the firm has type *β*. The last term in equation (A 7) presents the regulators aim to extract firm's informational rent. The derivative of equation (A 6) in respect of *e* is shown in brackets as $A \equiv \psi''(e)E_{\beta} + \psi'(e)E_{\beta C}C_e$. The sufficient condition for *A* to be positive is that $C_{ee} \geq 0$, which means that there are decreasing returns in the cost reducing technology and that $C_{\beta e} \geq 0$, which states that the marginal cost reduction is not higher for inefficient types.

From the equation (A 6), *A* can also be seen as the increase in the rent for all types $\lfloor \underline{\beta}, \beta \rfloor$ when the effort of type *β* is increased by one. The social cost of the extra rent for these types is $\lambda F(\beta)A$, which can be derived from the expected welfare function (A 5). The distortion in effort for type *β* relative to the first-best level $[\psi'(e) + C_e]$ has a social cost of $(1+\lambda)(\psi'(e)+C_e)$ from the equation (A 4). The relevant implication of equation (A 7) is that the regulator can use cost-reimbursement rules that lie in between the cost-plus contract (inducing $\psi'(e) = 0$ i.e. the marginal disutility of effort is null) and the fixed-price contract (inducing $\psi'(e) = -C_e$ i.e the marginal disutility of effort equals the marginal cost of effort).

Solution with asymmetric information

Under symmetric information, the marginal generalised gross surplus $\partial V / \partial q_k$ equals marginal social cost of production $\partial((1+\lambda)C) / \partial q_k$. However, under asymmetric information there may be an incentive correction associated with the regulator's aim to extract firm's rent. A unit increase in output *k* affects the rent by $\psi'(e)[dE_{\beta}/dq_k]$ from the equation (A 6), where

(A 9) $$\frac{d}{dq_k}(E_\beta) = E_{\beta C} C_{qk} + E_{\beta q_k}$$

is a total derivative that measures how output k affects the potential effort savings associated with an increase in efficiency. Equation (A 9 can be explained through the probability that the firm has type β. The gain in reducing $\dot{U}$ is proportional to the probability $F(\beta)$ that the firm is more efficient than type β and the cost of the distortion relative to the first best is proportional to the probability $f(\beta)$ that the firm has type β, which explains equation (A 8).

A conclusion from the equation (A 8) is that incentives and pricing of good k are disconnected if and only if $d(E_\beta)/dq_k = 0$. The regulator uses the cost-reimbursement rule to extract firms rent while preserving incentives. If $d(E_\beta)/dq_k > 0$ the price of good k exceeds its symmetric information level, in case $d(E_\beta)/dq_k < 0$, it is lower. Laffont and Tirole (1993, p.178) state that incentive correction favours high price (a low quantity) for good k if an increase in the output k increases the marginal rate of transformation between the effort and efficiency in the cost function. In other words: if the increase in output makes it easier for the firm to transform exogenous cost changes into rent, the incentive correction is favourable to higher price.

Appendix B

Table B.1: Prices in Denmark in 2002.

Price of the electricity distribution of type customers in Denmark in 2002							
cent/kWh	*2000 kWh*	*4000 kWh*	*15 MWh*	*100 MWh*	*250 MWh*	*1 GWh*	*1 GWh (10kV)*
average price	1.42	1.42	1.36	1.15	1.00	0.96	0.74
min	0.13	0.13	0.13	0.16	0.07	0.07	0.10
max	4.46	4.46	3.72	2.69	2.69	2.69	2.09

(Source: Dansk Energi 2002a.)

Table B.2: Prices in Finland in 2001.

Price of the electricity distribution of type customers in Finland in 2001										
cent/kWh	*2000 kWh*	*5000 kWh*	*10 MWh*	*35 MWh*	*18 MWh*	*20 MWh*	*150 MWh*	*600 MWh*	*2 GWh*	*10 GWh*
average price	4.06	3.24	3.11	2.18	2.23	1.93	2.32	2.01	1.45	1.39
min	2.33	2.19	1.82	1.36	1.39	1.13	1.63	1.30	0.88	0.86
max	6.25	4.41	4.23	2.86	2.96	2.59	3.26	2.93	2.24	2.17

(Source: EMA 2002.)

Table B.3: Prices in Norway.

Price of the electricity distribution of type customers in Norway in 2001						
cent/kWh	*4000 kWh*	*20 MWh*	*30 MWh*	*160 MWh*	*1.6 GWh*	*4 GWh*
average price	7.20	3.08	2.01	1.10	0.63	0.42
min	1.26	1.26	1.02	0.34	0.21	-0.04
max	14.23	5.13	4.48	2.36	2.31	1.43

(Source: NVE 2002b.)

Table B.4: Prices in Sweden.

Price of the electricity distribution of type customers in Sweden in 2001									
cent/kWh	*2000 kWh*	*5000 kWh*	*20 MWh*	*25 MWh*	*35 MWh*	*100 MWh*	*350 MWh*	*5 GWh*	*140 GWh*
average price	4.63	4.04	2.24	4.13	2.36	1.64	1.62	1.01	0.60
min	2.27	2.09	0.98	1.98	1.14	0.50	0.46	0.26	0.17
max	11.06	6.17	3.24	7.31	3.87	2.46	2.61	1.74	1.07

(Source: SNEA 2002c.)

Appendix C:

The complete efficiency results and the data tables are available from the author upon request.

kkinnunen@yahoo.com

Erklärung

Die vorliegende Dissertation mit dem Titel

> **"Network Pricing in the Nordic Countries – An Empirical Analysis of the Local Electricity Distribution Utilities' Efficiency and Pricing"**

ist von mir ohne fremde Hilfe angefertigt worden. Es sind keine anderen als die angegebenen Quellen und Hilfsmittel verwendet worden. Alle Stellen, die wörtlich oder sinngemäß aus Veröffentlichungen entnommen sind, sind als solche kenntlich gemacht worden.

Bremen, den 7.4.2003 Kaisa Kinnunen