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DIPLOMARBEIT

Economics and Regulatory Criteria of Distributed Generation, implemented in Denmark and Austria, with special Focus on Wind and Small-scale Combined Heat and Power Plants

ausgeführt zum Zwecke der Erlangung des akademischen Grades eines Diplom-Ingenieurs

unter der Leitung von

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Abstract

The main focus of this thesis lies in the identification of regulatory criteria of distributed generation and the resulting economics for renewable electricity generation (especially wind and biomass energy) in Denmark and Austria. The historical deployment of the Danish electricity system shows the main arguments of how to integrate distributed generation into the grids effectively. Furthermore, the present responsibilities of the different actors within the Danish electricity market are presented.

Economics of wind energy converters and small-scale CHP plants are discussed in detail illustrating the regulatory background. Hence, the resulting grid connection costs of distributed generators are pointed out and the necessary balancing expenses caused by a reliable system are considered, in order to discuss “best-practice” regulatory criteria.

From this point of view, the organizational structures within the Danish as well as the Austrian electricity systems are discussed in detail, analyzing the currently used integration strategies of distributed generators. The calculated Austrian grid connection costs amount to approximately 300 percent compared to Denmark whereas the balancing expenses are four times higher than Danish ones.

Conclusions point out that the above mentioned results are mainly caused by the implemented “Shallow Cost” grid connection approach in Denmark, which is more favorable for distributed generators. Since a main part of the grid connection costs of renewable electricity generators are socialized among the Danish population, more incentives are offered to new investors of these plants.
Furthermore the smaller balancing costs are a consequence of the smaller forecast error and the bigger balancing market, as Denmark is part of the Nordic power market. Shorter generation forecast periods require a smaller demand on balancing power, decreasing its price.
Finally, since Danish households are obliged to be connected to the local District Heating Systems and consequential the achieved heat prices dropped, the penetration of small-scale CHP plants increased enormously.

Although Austria cannot copy the Danish system it is a good model in order to integrate distributed generation, especially in the balancing and grid connection matters. Essential directives should be reconsidered in Austria in order to promote the development of distributed generation.

Kurzfassung

Das Hauptaugenmerk dieser Diplomarbeit liegt auf der Analyse der gesetzlichen Rahmenbedingungen die für den breiten Einsatz dezentraler Energieversorgung nötig sind und den daraus resultierenden Wirtschaftlichkeitsaspekten erneuerbarer Stromerzeuger in Österreich und Dänemark. Die historische Entwicklung Dänemarks spiegelt optimale Integrationsmöglichkeiten verteilter Energieerzeugung (im Detail für Wind- und Biomasse) in die Netzinfrastruktur wider und stellt die Aufgaben der verantwortlichen Marktteilnehmer dar.

Wirtschaftlichkeitsanalysen von Windstromerzeugern und Klein-KWK – Anlagen werden detailliert diskutiert, um die dahinter stehenden Gesetze und Verordnungen aufzuweisen. Daraus resultierende Kosten der Netzintegration dezentraler Energieversorger und jene der benötigten Ausgleichsenergie, die ein zuverlässiges Netz erfordert, werden in dieser Arbeit diskutiert.

Weiters wird sowohl auf die interne Organisationsstruktur des dänischen als auch des österreichischen Elektrizitätsmarktes eingegangen. Die wichtigsten Unterschiede der aktuellen Integrationsstrategien dezentraler Energieversorger werden erarbeitet, um die dreifachen Netzintegrationskosten und die vierfachen Ausgleichsenergiekosten in Österreich zu erörtern.

Schlussfolgerungen ergeben, dass die zuvor genannten Unterschiede der Systeme hauptsächlich mit der Implementierung des Netzzuganges eines „Shallow Cost Approachs“ begründet werden. Jene kommen dezentralen Energieversorgern sehr entgegen. Dänemark sozialisiert einen Großteil der Netzkosten auf alle Konsumenten innerhalb des Elektrizitätsnetzes entsprechend einem Einheitsmodel, wodurch deutliche Anreize für Investoren erneuerbarer, dezentraler Energiequellen geschaffen werden.
Als weiteres Entscheidungsmerkmal wird der geringere Prognosefehler mit der dadurch verbunden niedrigeren Nachfrage an Ausgleichsenergie erkannt. Auch spielt hier der um ein vielfaches größere Ausgleichsenergiemarkt in Dänemark eine positive Rolle.
Den hohen Anteil an Klein-KWK – Anlagen verdankt Dänemark der gesetzlich geregelten Anschlusspflicht jedes Haushaltes an das örtliche Fernwärmenetz und der gut ausgebauten Fernwärmeinfrastruktur.

Österreich kann aufgrund seiner geographischen Lage das dänische System zwar nicht kopieren, aber es liefert dennoch hilfreiche Ansätze, um diverse Integrationsstrategien zu überarbeiten.

1. Introduction

My diploma thesis points out the economics and regulative criteria of an economical feasible electricity market enabling high penetration of distributed, renewable electricity generation. Since Denmark has many experiences in the integration of distributed generators the focus of this thesis is laid on the Danish system in order to give advises to the Austrian electricity system. Beyond that, I had the opportunity to spend four months at the Roskilde University, which provided me national expertise to use for my diploma thesis.

1.1 Motivation

Since electricity systems of nowadays are increasingly penetrated by renewable electricity generation, the integration and political support of distributed generation became a main topic. Since Denmark developed efficient strategies in order to promote integration, this diploma thesis compares the results of the chosen solutions in Austria and Denmark. Moreover, a high percentage of the installed distributed generators are renewable energy converters to better meet the national and international agreements on primary energy savings and CO2 reductions.

The integration of distributed renewable energy sources implicates several matters which have to be considered as well. Since renewable energy converters as wind turbines or biomass CHP plants are currently not competitive on the electricity market, political strategies and subsidy schemes are developed. Different subsidy schemes cause different results at the energy system.
Furthermore, renewable energy converters are sometimes considered as volatile energy sources and therefore more exact forecasting tools are required in order to reduce the demand on regulative power. The impact of power prediction errors on electricity generation costs became an important issue of present electricity systems.

Finally, the grid connection approach of distributed generators is an important issue nowadays. Different approaches cause different investment costs resulting in varying electricity generation costs and changing efficiency rates of the grid utilization. These facts have an intensive impact on the social acceptance among the population and play therefore an important role in political decisions.

1.2 Objective

The core objective of this work is to identify the key-issues of a successful integration of distributed generation into electricity systems. Since Denmark developed effective strategies, the most important parameters and their impact on the economics of the distributed generators are analyzed and compared to Austria in detail.

1.3 Organizational structure of the thesis

Chapter 1 is concerned with the historical deployment of the Danish electricity system and the political support of the integration of distributed generation and renewable energy sources. Furthermore, the deployment of the transmission grid and several distribution grids are presented as well.

Chapter 2 addresses the Danish electricity system of nowadays and especially highlights the situation on the balancing market. Different responsibilities are discussed and an organizational structure visualizes the interaction of the market participants. Furthermore, the regulative criteria of the market integration of renewable energy technologies are explained.

The focus of **chapter 3&4** is laid on the economics of wind energy technology and small-scale CHP plants in Denmark. The different impacts on the electricity generation costs as well as experience curves and heat revenues are mentioned. Furthermore, balancing costs of wind energy are discussed and the Danish situation of industry and household CHP plants is presented. Additionally, the grid connection costs of distributed generators are discussed and the Danish strategy in order to socialize the grid-connection costs is discussed as well.

Chapter 5 analyzes the organizational structure of the Austrian electricity system and the balancing methods. The interaction of the different regulative institutions is explained and the resulting performance is visualized. An overview of the historical political efforts in the promotion of RES-E is given.

Chapter 6 concerns the economics of wind energy and small-scale CHP plants in Austria. Electricity generation costs and heat revenues are presented and the influences of different parameters such as risk premiums are analyzed. Furthermore, the Austrian balancing market and grid connection approach is discussed. Case studies of wind parks and small-scale biomass CHP plants point out the interaction of economics and political support.

Chapter 7&8 compare the results of RES-E integration in Austria and Denmark. Sensitivity analyzes illustrate the impact of certain parameters such as, balancing costs or grid connection costs, on the electricity generation costs. Conclusions about the more favorable system for distributed generation are drawn.

Chapter 9 summarizes the main aspects and conclusions of this diploma thesis.

2. Historical deployment of the electricity supply system in Denmark

2.1 The initiation of renewable electricity generation in Denmark

Denmark is one of the leading countries in the European Union in RES-E production. This is so due to a long planned and organized way of introducing renewable energy sources into the electricity production. In the early seventies nearly all of the observed renewable electricity production was generated by Biomass, whereof wood had the biggest share. A few years later, the production of crude oil in Denmark started and became more dominant in the beginning of the eighties although it stabilized quickly at a percentage of almost 60%.

Although the climate adjusted gross energy consumption has been stable over the past twenty years, the production of electricity was increasing year by year. This affected an approach in self-sufficiency in energy of 100 percent and more. Self-sufficiency is the result of the converted primary energy in relation to the gross energy consumption.

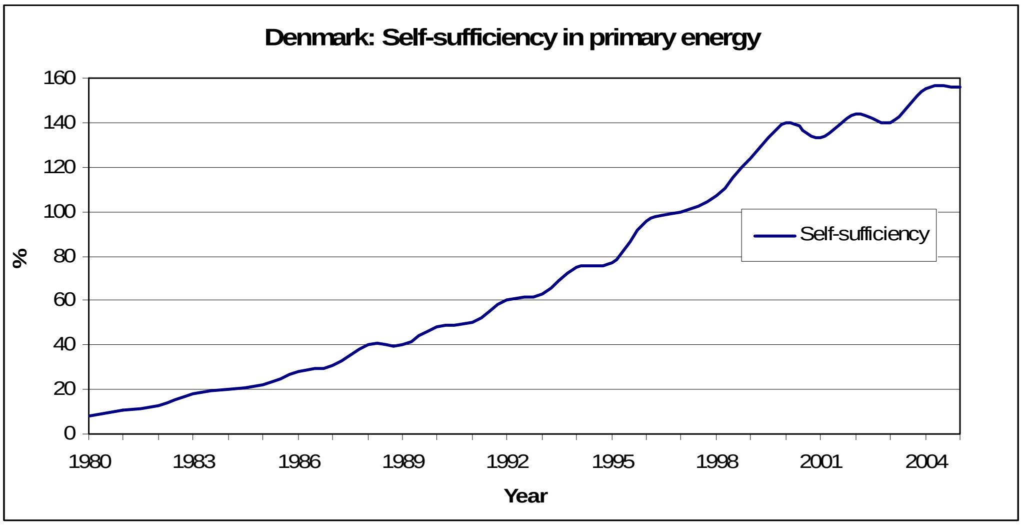

Figure 2.1 Degree of self-sufficiency in energy; Source (Danish Energy Authority, 2005)

As is shown in figure 2.1, the complete self-sufficiency in energy was reached in 1997. Due to the enormous production of crude oil in the North Sea, most energy exports are made with oil. In 2005 the production of crude oil was more than double of oil consumption and the approved, economic conveyable oil reserves of Denmark were still 1,3 billion barrels at the end of 2005 (European Commission, 2007).

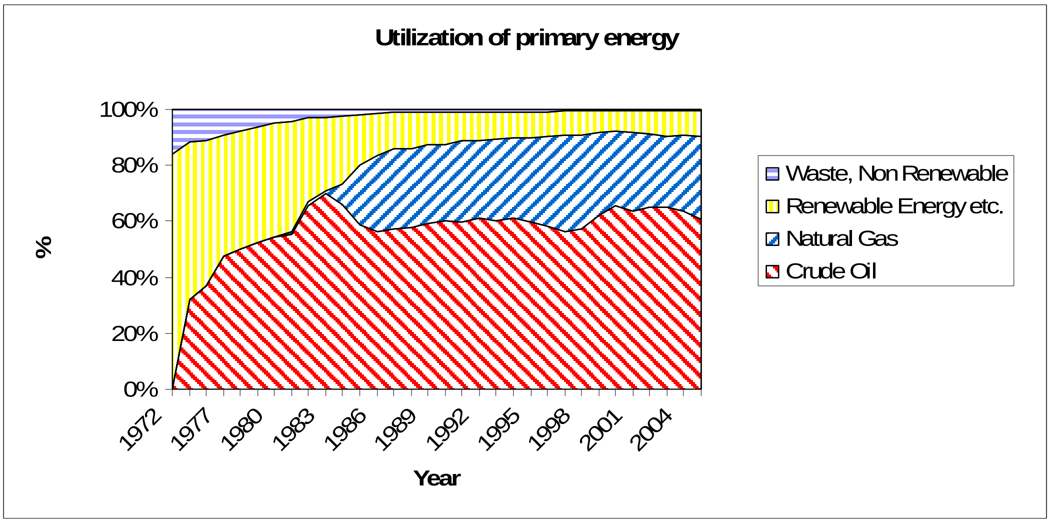

Figure 2.2 Share of primary energy conversion in Denmark; Source (Danish Energy Authority, 2005)

In figure 2.2 it is visible that Denmark is the second largest oil producer in the EU, but also the constant growth of renewable energy utilization is indirectly visualized. Due to the fact that the energy utilization grew year by year, and the percentage of renewable energy in figure 2.2 is constant, the figure reflects a constant growth of the renewable energy utilization.
The main fields of renewable energy usage are electricity production and district heating systems. Due to this fact, in the year 2005 more than 28 percent of the Danish electricity production was generated by renewable sources and almost 34 percent of the district heating fuel belonged to renewable energy. The promotion of favoring renewable energy occurred together with strong support from the government and legislations from the EU as well.
As is discussed in detail in the next chapter, the Danish government introduced already in the late seventies several action plans in order to reduce CO2 emissions and herewith support the competences of renewable energy production on the electricity market. Furthermore most of the legislations from the EU got intensified by the Danish government.

The major part of the renewable electricity is generated by wind. Therefore, the world's leading windmill manufactures are located in Denmark and again the government tried to push the Research and Development (R&D) of more efficient windmills by financial support. Nowadays all interesting places for onshore windmills are occupied by them and there is no place to build new ones. This way Denmark starts to repower old windmills by new, powerful windmills. The reason why no more suitable places for windmills can be found is their impact on the environment. Such impacts are for instance noise and visual impacts on nature.

In the North Western part of the country, the wind usually blows strongest and it is also best predictable there, therefore a high density of wind mills is installed there.

Moreover, the landscape is very flat and there are no obstacles or wind shades, reducing the electricity output.
Furthermore, the overhead DC cable from the connection to Norway enters Denmark at this part of the country, where an electricity surplus, for instance in a cold, windy winter night, can be exchanged within the Nordic electricity market NordPool.

Since the installed capacity of wind power in Denmark is as big as it is nowadays, wind energy plays an important role in the electricity supply system. Nevertheless, wind energy is still subsidized by the government in order to be competitive at the electricity market. The increasing share of wind energy has not only advantages, because wind speeds are still difficult to predict exactly. Therefore, wind turbines require a higher percentage of back-up power and the connection to the distribution grid also increased the costs of electricity in the past. Nevertheless, the impact of an increasing share of distributed generation on the electricity bill of end-consumers is small compared to the impact of increased electricity taxes.

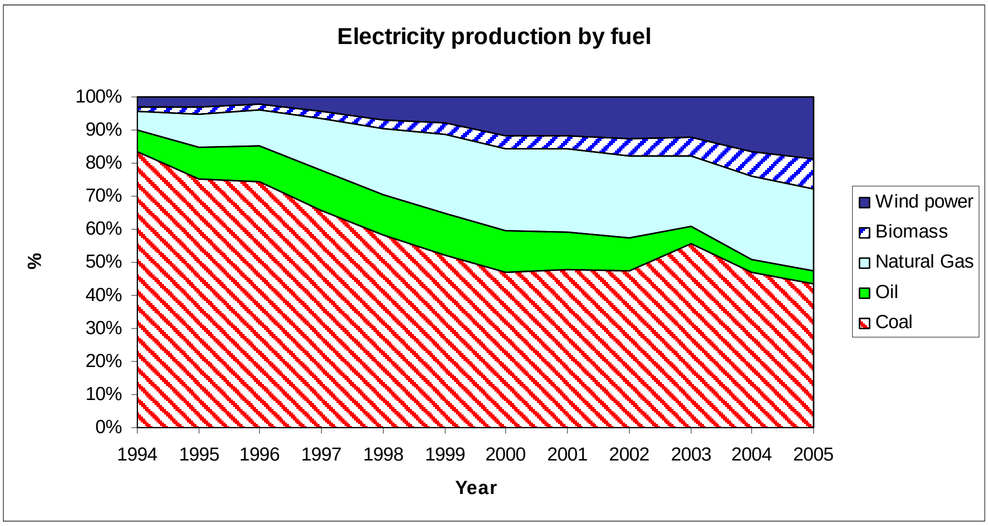

Figure 2.3 Electricity production sorted by used fuel; Source (Danish Energy Authority, 2006)

Figure 2.3 illustrates the growing fuel utilization in electricity production. While coal was the overall dominating fuel in the past decade, it now dropped to 42,6 percent of the total used fuel whereas the share of natural gas and wind power increased slightly.
This high penetration of windmills was reached by incentives given by the government to windmill owners. Already in the early eighties power utilities were required by law to purchase the electricity generated by private windmills. Furthermore, the government paid grants of 30% of the investment costs to windmill owners to expanse the wind power production. In 2000 the government wanted to introduce the renewable energy certificate market, where turbine owners would sign contracts in order to receive a fixed minimum price of 4,43 c€/kWh for the first ten years and a green certificate of a minimum of 1,34 c€/kWh up to 3,63 c€/kWh. So the

total could be 8,06 c€/kWh, which was the fixed feed-in tariff before. Furthermore customers would have been obliged to buy at least 20 percent of their electricity from renewable sources, and if they bought less, they would have to pay a tax of 3,63 c€/kWh as a punishment. This market was supposed to come into force in 2003, but the new government decided that this certificate market was too complex. Because other countries follow other strategies, the introduction of the market was canceled in order to harmonize the subsidy scheme in the EU. Therefore, another subsidy scheme was introduced which subsidizes wind production depending on the time of erecting the wind turbine. This will be discussed in detail in the following chapter. (OECD, 2002)

Due to the fact explained above, the government tries to promote the replacement of old wind turbines by new powerful ones by paying subsidies. For refurbished windmills existing before January 2003, a subsidy of 5,78 c€/kWh is guaranteed for the next 10 years. Moreover, an additional subsidy can be received for a certain number of full-load hours per year.
New wind turbines can only receive a subsidy of 4,43 c€/kWh for the first 22000 full-load hours and will afterwards run on the market price. Nevertheless, another premium of 1,34 c€/kWh can be received as long as the renewable energy certificate market does not come into force.

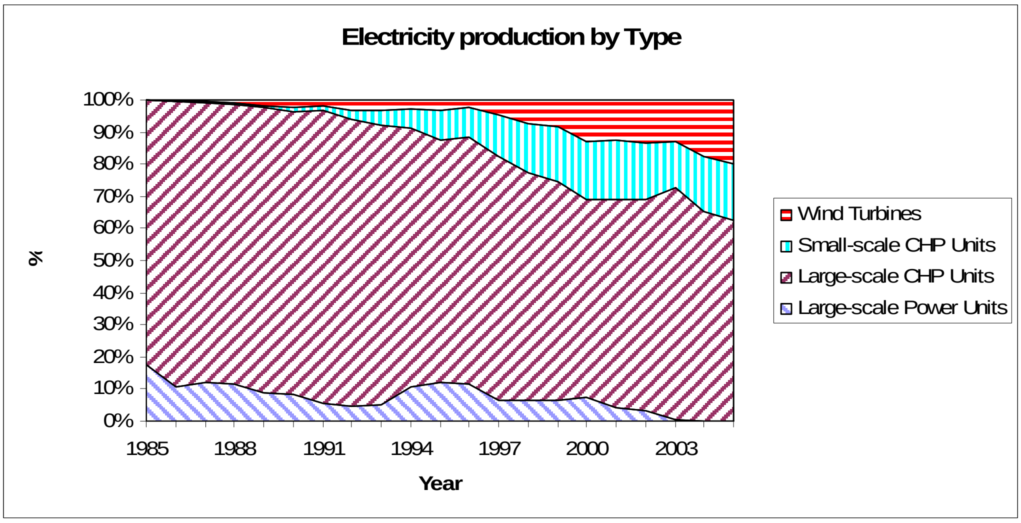

Figure 2.4 Electricity production sorted by type of production; Source (Danish Energy Authority, 2006)

Obviously, there are two steps in the development of wind power shown in figure 2.4. The first boom was in 1996 when the commitments of the (Energy21) plan came into force, which required the supporting of renewable energies and the second step was before 2003 when the turbine owners got much higher subsidies for refurbishing their old wind turbines than they would get for a new turbine.
Furthermore, figure 2.4 shows the increasing share of local CHP plants at the beginning of the nineties when the (Energy2000) action plan was issued. This

agreement is said to improve the energy efficiency in the future. CHP plants are considered much more efficient than a stand-alone power and heat production plant, because for the same input of fuel, the output is more or less the double amount of useful energy. Denmark was supplied by fourteen big central CHP plants and they covered almost 40 percent of the required district heating in 1980. The heat demand in 1999 was already covered by 80 percent from CHP thus because of the expansion in local CHP plants.

Small scale CHP plants built within the program (Energy 2000) had to be fired by natural gas, waste or biofuels (straw, wood and biogas). In 1999 about 80 percent of the small scale CHP's were gas fired, depending on their location. The domestic natural gas production is distributed to many parts of the country. If it is economically efficient to use natural gas, CHP's are fired by natural gas; if not, they use biofuels or waste. Several CHP can run on coal too, but they are just allowed to use the coal for peak-load or backup power (Hannemann et al., 1993)

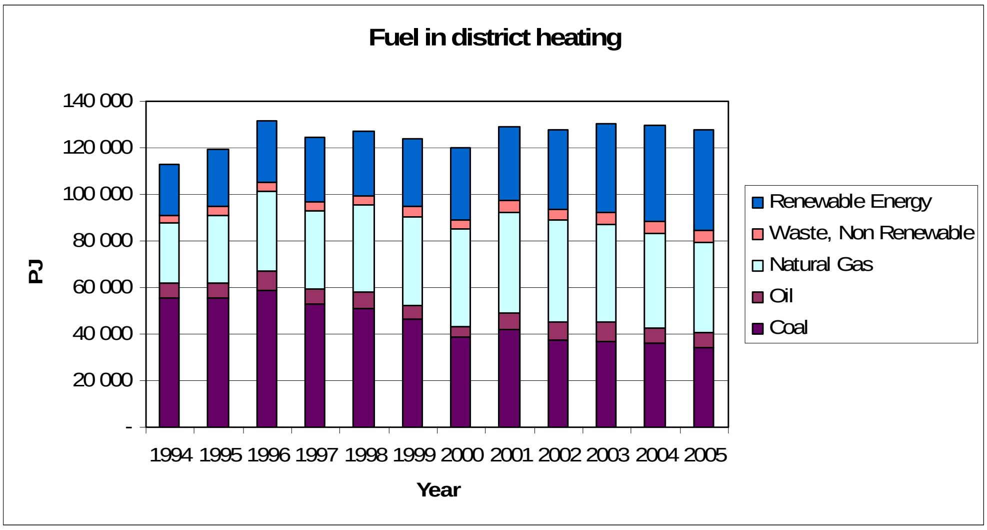

Figure 2.5 Fuels used in the district heating systems; Source: (Danish Board of district heating, 2007)

Figure 2.5 demonstrates the overall fuel used in Denmark for district heating. The amount of coal dropped annually and finally got substituted by natural gas. The increasing demand on heat was covered by building new CHP's, using renewable energy sources.

Subsidies for CHP's depend on the age, the power size and the fuel of the plants. Existing, decentralized and natural gas-fired CHP's with a power less than 10 MW are based on a three-time-tariff, which is regulated every 15 minutes. The grants for produced electricity are 3,9 c€/kWh in base load, 7 c€/kWh at high demand and 9,1 c€/kWh at peak load. CHP plants using only renewable sources will get a fixed 8,06 c€/kWh subsidy; it is made up of subsidy plus market price. Later on, the subsidy rules will be discussed in detail (Danish Energy Authority, 2007).

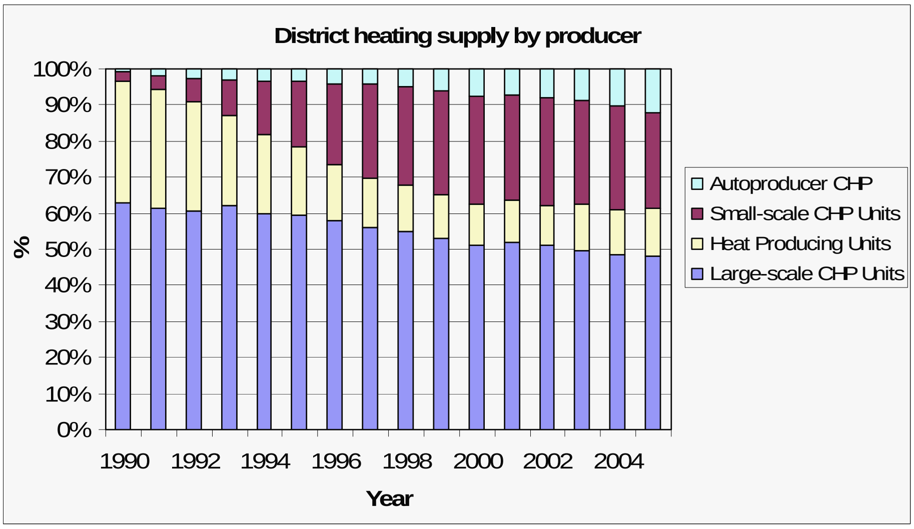

Figure 2.6 District heating supply system sorted by producers; Source: (Danish Board of district heating, 2007)

Figure 2.6 shows that the incentives, which were given in the early nineties, are supporting the action plans of the government. On the one hand, the conversion from heat production units to CHP plants already took place and on the other hand, the number of local CHP's increased enormously in the early nineties when the new Heat Act got issued. It is expected that the share of local CHP plants will increase in the future in order to achieve the aims of the (Energy21) action plan in reducing CO2 emissions.

Figure 2.5 as well as figure 2.7 highlight the growing market share of local CHP plants in producing electricity and heat for district heating systems. This was part of the aim of the (Energy 2000) action plan to increase the energy efficiency. While in 2005 almost 50 percent of the local, small-scale CHP plants were fired by Biomass, the large scale CHP's were still dominated by coal fired plants. Moreover, the small-scale CHP's are controlled on heat demand, whereby most of the plants have a tank to store heat in order to produce energy at the high price of the three-time tariff of electricity, whereas the large-scale CHP plants run primarily to cover the electricity demand (Danish Energy Authority, 2006).

2.2 The increasing penetration of DG

In Denmark, the penetration of distributed generation (DG) of nowadays has been achieved due to some general conditions. Those are economical considerations as benefits and incentives for the Distribution System Operator (DSO), which are mostly jointly owned by the consumers, or the Third Party Access, which allows consumers to choose their own supplier, as well as technical considerations, like providing balancing power or reinforcements of the distribution grid.

All these kinds of preparations for favoring DG have been made due to some energy programs and the legislation of the Danish Parliament. One of the first big programs was the action plan (Energy 2000), carried out in 1990. The main interests of this plan lied in a sustainable development of the energy supply system, energy-efficiency and to improve the reliability of the energy supply system. In 1995 other legislations were introduced by the government, called "*The green packet for trade and industry*". Within this program it was stated that renewable energy generation should be taken into account in order to achieve a CO2 emission reduction. The Danish energy programs have always been stricter than the ones prescribed from the EU. Due to this fact, in 1996, the (Energy21) (OECD, 2002) action plan was carried out by the Danish government. The aims of (Energy21) were the farther development of renewable energy generation, together with making them economic and competitive on the market. Due to different supports and subsidies the share of renewable generation should grow continuously. Another task of (Energy 21) was to stabilize the overall energy consumption in the future, because a rising economy was expected. Furthermore, the self-sufficiency in the Danish energy supply system should improve as well.

How successful the different programs worked and cooperated between each other points out figure 2.7. While the aim of (Energy21) was a share of 12% up to 14% of renewable energy consumption in the year 2005, it actually amounted to 15,5% in the year 2005.

Furthermore, the environmental impact could be stabilized due to the above mentioned increasing generation of RES. The CO2 emissions stayed stable in the period of 1990 to 2000 and reduced in 2005 to 85% of the year 1988. The only exception with much higher CO2 emissions was the year 1996, due to the comparatively hot summer which caused a smaller electricity production of the hydro power plants in Norway. So Denmark was forced to export much more electrical energy to the Scandinavian power market, by running conventional power plants.

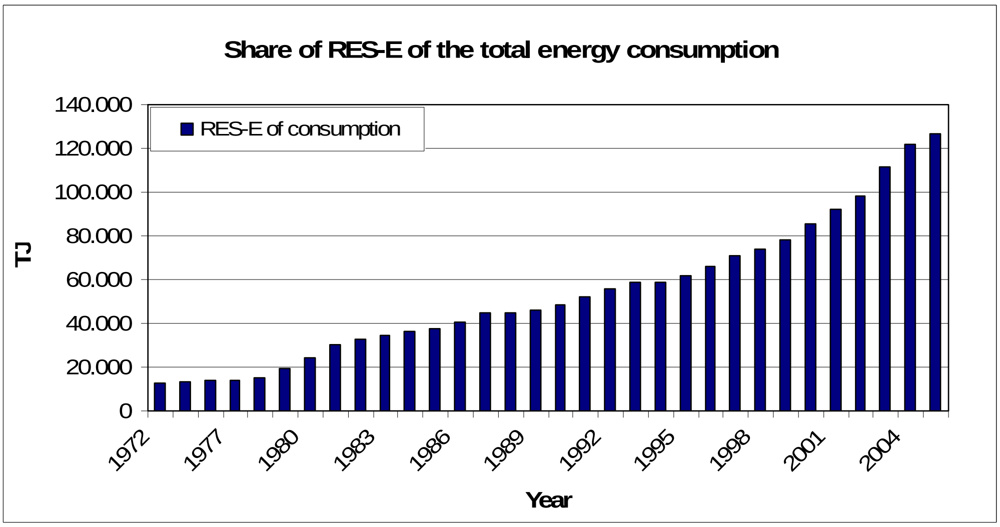

Figure 2.7 Share of the renewable energy generation of the total energy consumption in Denmark; Source: (Danish Energy Authority, 2005)

The Danish Energy Agency published a report in 2002, which shows the kind of electricity generation sorted by fuel. In 2000 coal was still the leader with a share of 46,3 percent, instead of 90 percent in 1990, followed by natural gas with 24,9 percent, oil with 11,8 percent and wind with already 11,7 percent.

It is to point out that almost 38 percent of the whole electricity production in 2000 were generated decentralized whereas 26 percent were provided from local small scale Combined Heat and Power generators (CHP) and the rest from windmills.
Due to a lot of other governmental legislations the DG penetration rose in 2004 up to 44 %, whereas CHP's produced 66 % and windmills 34 % (Pedersen T. M. et al., 2005).

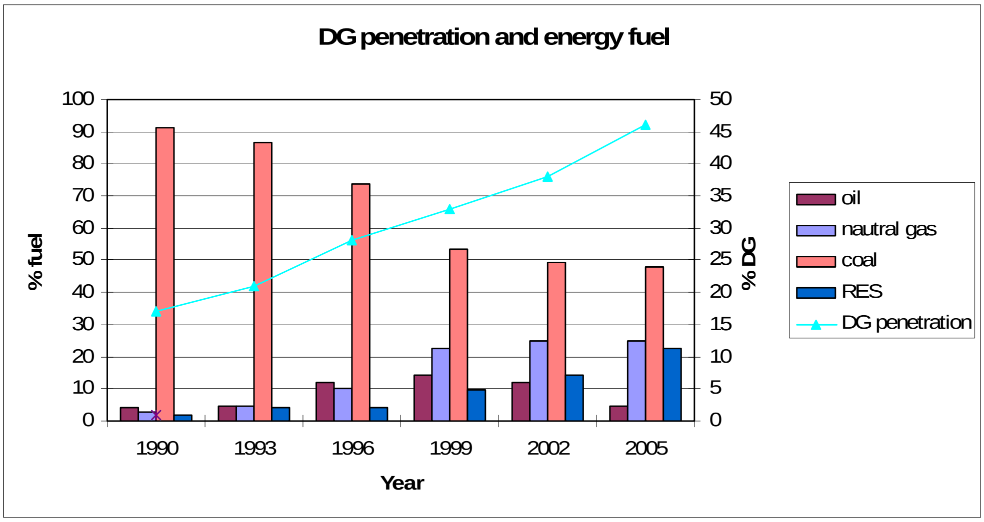

Figure 2.8 DG penetration level and compared utilization of fuel in the Danish electricity production; Source: Danish Energy Agency and Eltra Transmission Company

Figure 2.8 demonstrates the impacts of the afore mentioned government legislations. Especially mentioned should be that the increasing DG penetration level occurred because of the supports and promotion of RES. Another aspect which is also visible in figure 2.8 is that the Danish government decided in the mid eighties that a new power plant will only get commissioned if it is a CHP and also provides the heat to a local district heating system. So a lot of small scale CHP's appeared in smaller urban areas providing heat and power to the cities and the energy efficiency rose dramatically. Whereas in 1980 just 40% of the district heating system was supplied by CHP's, in 1999 already 80% were covered by CHP's.
The DG production can be divided into two parts, the controllable and the non-controllable production. In this case controllable means to have the possibility to operate the power plant corresponding to the energy demand. To the controllable DG production counts mostly the local CHP's, while non-controllable are the windmills. A windmill depends more on unpredictable influences like wind speeds.
In 2004 the DG production was split according to the figures the following table 2.1 shows.

Table 2.1 Percentage of DG production in Denmark in 2004; Source: (DanskEnergi, 2005)

	West DK	East DK	DK total
	[%]	[%]	[%]
DG total	57	24	44
Controllable	35	19	29
Non-controllable	22	4	15

Table 2.1 illustrates a much higher percentage of non-controllable DG production in the western part of the country. This is caused by the better locations for windmills on the west shore of Denmark. Offshore windmills are not taken into account because they are not regarded as DG.

Denmark is a pioneer in forcing DG favoring RES. This fast development emerged because of a good and strong subsidy scheme of renewable energy production and energy efficiency. So they started already in the early eighties with financial support for wind energy and in 1992 also renewable CHP plants were subsidized for their electricity production. In the same year the government obligated utilities to purchase electricity from windmills and renewable CHP's for a certain price. Those feed-in tariffs followed the long term marginal costs, in a three time tariff (low, middle, high tariff period). This is one of the reasons why small scale CHP's had their boom in the mid-nineties.

2.3 The necessary modifications in the transmission grid

Until 2005 the Danish transmission system was divided into two separate parts. Eltra owned and operated the western part of Denmark, called Jutland, and Elkraft Transmission was the operator of the transmission network of the eastern part, called Zealand. The Zealand grid was jointly owned by three companies. Since 2005 the whole Danish transmission network has been owned and operated by Energinet.dk. So far, there is no direct connection between the two parts of Denmark, although a DC-connection cable is already approved by the Danish Energy Authority but has not been installed yet. Nevertheless, indirect power exchanges are possible due to the connection of both parts to Norway and Sweden in the Northern electricity market, NordPool.
Due to the fact that Eltra and Elkraft Transmission were not just the operators of their networks, both benefited from a natural monopoly as owners and operators of public infrastructure facilities. The two grid transmission companies were founded in the year 1998 as a result of the Electricity Supply Act (Act No. 486) and an electricity directive of the European Union. Since that, Eltra consisted of 48 Danish grid companies in Jutland, and Elkraft Transmission was jointly owned by ten eastern Danish grid companies (OECD, 1997).

Eltra and Elkraft Transmission were responsible for the maintenance of the grid and a save running of it, the interaction between two neighbor-areas and the maintaining of the physical balance in the grid. Moreover, the TSO’s had only to balance the wind energy in their areas, they also had to pay for the needed balancing power. This changed slightly and since 2005 Energinet.dk only balances the old wind turbines, new ones pay their balancing on their own.

Furthermore, the two companies had to handle the so called “priority dispatched” regulation. “Priority dispatched” means that renewable energy converters generate as much electricity as possible and not according to their before notified amount of electricity. For instance are wind turbines considered as a volatile energy source which has to be dispatched if the wind blows regardless to the present electricity demand. Due to these facts and that the TSO’ s paid for the balancing, local CHP plants and wind turbines had to be dispatched whenever they produce electricity and so they belonged to the electricity production methods which enjoy this “priority dispatch” regulation.
Because of the high penetration of decentralized energy generation in Denmark, the “priority dispatch” rule could become a problem in cold, windy winter nights. Then there is a high heat demand, hence the CHP plants run on maximum load and wind turbines are also producing much more electricity than needed. Now the legislation

says to dispatch CHP plants and wind turbines first, regardless of the demand and their location in the electricity grid.

A corrective in this matter was to export all the excess electricity to the Northern electricity market, NordPool. This requests a strong domestic transmission grid and powerful connections to the neighbor-countries. In the cases of windy nights, as explained above, most of the electricity is sent to Norway and Sweden because the penetration of wind turbines in Germany is very high as well, so that there is no demand of electricity.

Due to the electricity exchange between Denmark, Norway and Sweden the domestic transmission grid has had to be reinforced in order to avoid bottlenecks. An enormous improvement was the new 400 kV cable between Arhus and Aalborg, in the middle part of Jutland. Furthermore, the sea cables to Norway and Sweden got reinforced when the electricity market got liberalized. Western Denmark has a total electric connection capacity of approximately 2900 MW, but 1200 MW are linked to Germany and out of the rest the stronger connection exists to Norway. That is a result of the Swedish requests for each kWh, which is seen as an obstacle in trading electricity in the NordPool. Denmark has to pay 0,27 c€/kWh as a border tariff. Eastern Denmark has interconnections to neighbor-countries too, so there are two 400 kV AC cables and two 132 kV cables to Sweden. The Danish island Bornholm, which is located south-east of Sweden, is served from Sweden, by trading electricity between the eastern part of Denmark and Sweden.

However, a lot of reinforcements already took place in Denmark but there are still some bottlenecks left, especially in the western part of the country, electricity trade is not as good as it could be due to the electricity generation situation (Energinet.dk, 2007).

Scientists conducted researches on the question if it was economically feasible to reinforce the domestic transmission grid as well as the power cables to Norway and Sweden, and if yes, under which conditions.

The analysis of the Danish transmission grid in 2005 illustrated an available export capacity, which in a winter week sometimes went down to zero and in a summer week had an approximately 700 MW higher average value. Here it is to mention that the available export capacity is defined by physical export capacity minus the momentary export rate.

In these researches a 600 MW HVDC cable was considered as the optimal reinforcement to Norway and Sweden which would have brought with it costs of 181 million Euros in total. All the results will be mentioned in the following paragraph, regardless of the costs of further wind turbines, only the costs of the reinforcement of the transmission grid will be compared to the benefits of more electricity export to the Nordic pool, NordPool.

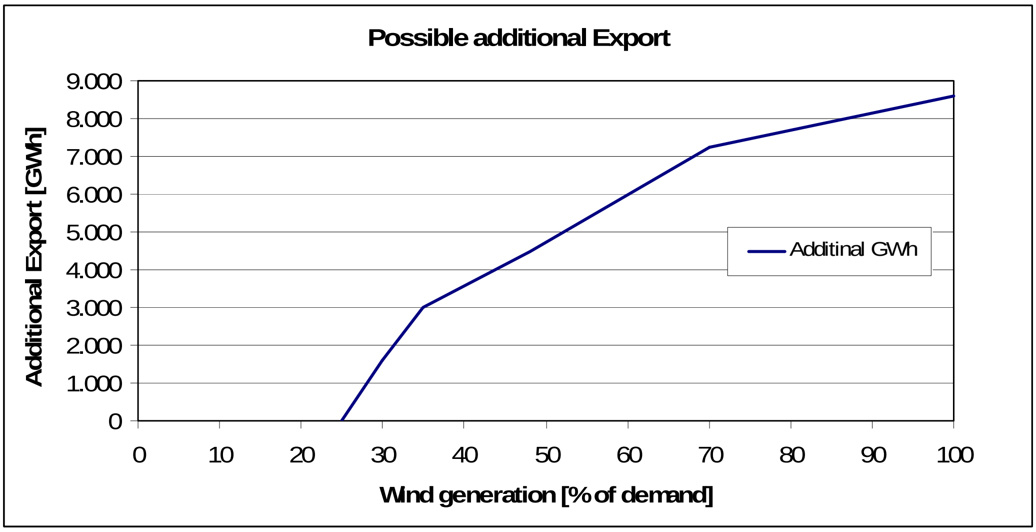

Figure 2.9 Additional exports to the NordPool with a rising share of wind generation; Source: (Aalborg University, 2005)

Figure 2.9 demonstrates the possible additional export to the Nordic market NordPool if the reinforcement would take place. In order to sell electricity at the market, the share of electricity produced by wind turbines must increase constantly, whereas the costs of refurbishment of wind turbines, respectively of new wind turbines are not considered in the analysis, as mentioned above. The price for electricity is dictated by the Nordic power market NordPool, and varies every hour.

The benefit of the reinforcement with a 600 MW cable results of the annual costs for the cable, the incomes of the sold electricity and also of reinforcements which have to be made in the countryside. These reinforcements in the country increase with the rising share of wind turbines, leading to the fact that the benefit does not increase in a constant manner with the share of electricity production of wind. A percentage of 80 percent or higher of electricity produced by wind, needs a dramatically increasing reinforcement in the country because of the necessary connection of all new wind turbines. These reinforcements have to be paid by the TSO, because a higher percentage of wind turbines can only be achieved by offshore wind parks. As some researches recommended, offshore wind parks are to connect to the transmission grid and not to the distribution grid like onshore wind turbines.

The resulting benefits with consideration of onshore reinforcement as well as the 600 MW cable to Norway and Sweden, but regardless of costs of new wind turbines, are shown in figure 2.10 below.

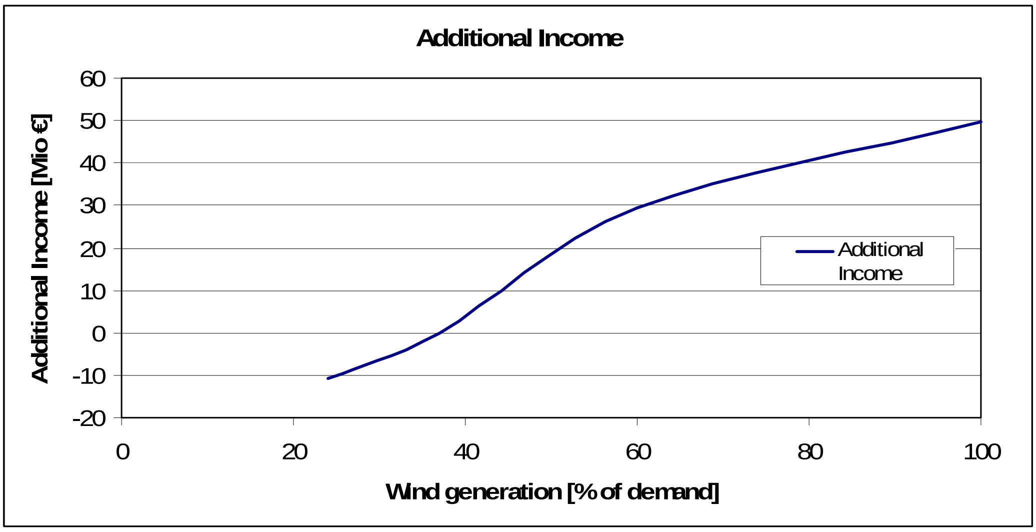

Figure 2.10 Benefit of the 600MW cable to Norway and Sweden by regarding onshore reinforcement costs, Source: (Oestergaard, P.A.; 2005)

The result shown in figure 2.10 illustrates that the reinforcement would only be economically feasible if a share above 40 percent of the electricity demand is produced by wind turbines. The additional income also depends on the wind conditions which vary every year and finally the weather situation in Norway and Sweden plays an important role. If it is a rainy year, Norway will cover all its electricity demand by their own hydro power plants and there won't be any need for electricity imports. Furthermore, the investment costs for new wind turbines have to be considered too, in order to make a final decision (Oestergaard P. A. et al., 1999).

However, since April 2007 a 600MW connection line between Jutland and Zealand is approved and is expected to run within the next years. Scientists expect an avoidance of several bottlenecks in the transmission grid all over Denmark and due to the new sea cable an increasing export to neighbor-countries will be possible.

2.4 The necessary modifications in the distribution grid

Distribution grids in Denmark are electricity networks which are operating on voltage levels at 0,4kV, 10kV and 60kV. These grids are operated by the local Distribution System Operators (DSO) of which nowadays 115 exist in Denmark. In most cases the Distribution System Operators are elected every four years by the local authorities and the grid is owned by the costumers or authorities, depending on the size of the grid. Small distribution networks were mostly built up by the customers themselves and are still owned by them, whereas in bigger cities the grid is owned by the authorities.

Figure 2.11 illustrates the changing of the distribution grids all over Denmark in newly installed kilometers.

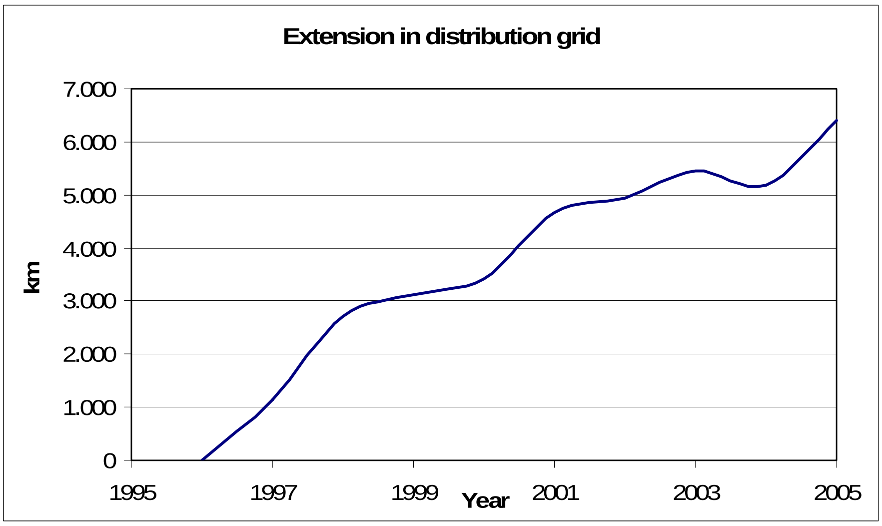

Figure 2.11 Total extension in the distribution grids since 1996; Source: (Statistics Denmark, 2006)

Figure 2.11 shows that the extension in the distribution grid happened in steps of approximately two years because if a grid gets reinforced or extended designers choose a cable with a higher capacity as it is required at the moment, the following grid connection of another energy producer does not require any extension. The more foresighted a Distribution System Operator extends his grid, the more efficiently he can plan his grid and moreover the smaller are the grid tariffs for the consumers, who in some cases jointly own the grid. Furthermore, this Distribution System Operator will also be one of the most cost efficient DSO' s, whereby he is allowed to make a little profit. In this way the changing from a non-profit DSO system to the present system with little incomes is seen as an incentive to operate the grids more efficiently.

It is the Distribution System Operators' responsibility to run the network reliably in every moment. That means that the DSO's have to connect every household in their areas as well as they are applied to connect wind turbines and local CHP plants to their grids. If it is necessary to reinforce or extend the grid or to set up new transformer stations they have to invest in the grid. DSO companies had to be non-profit companies. This means that they had to regulate their grid tariffs four times a year to cover their costs, but were not allowed to make any profit. Since 2005 DSO's with high cost efficiencies are allowed to make a little profit, but this profit varies every year.

The grid tariffs are calculated on the basis of the expense of investments in the grid and the network operating costs. On the other hand, the expenses of investments in the grid are socialized according to a model from the TSO Energinet.dk. The difference between incomes from that model and the rest of the expenses are covered by the grid tariffs. These tariffs have to be approved of by the Danish Energy

Regulating Authority (DERA) and vary from area to area. The more efficient a DSO works, the smaller are the tariffs for the customers.

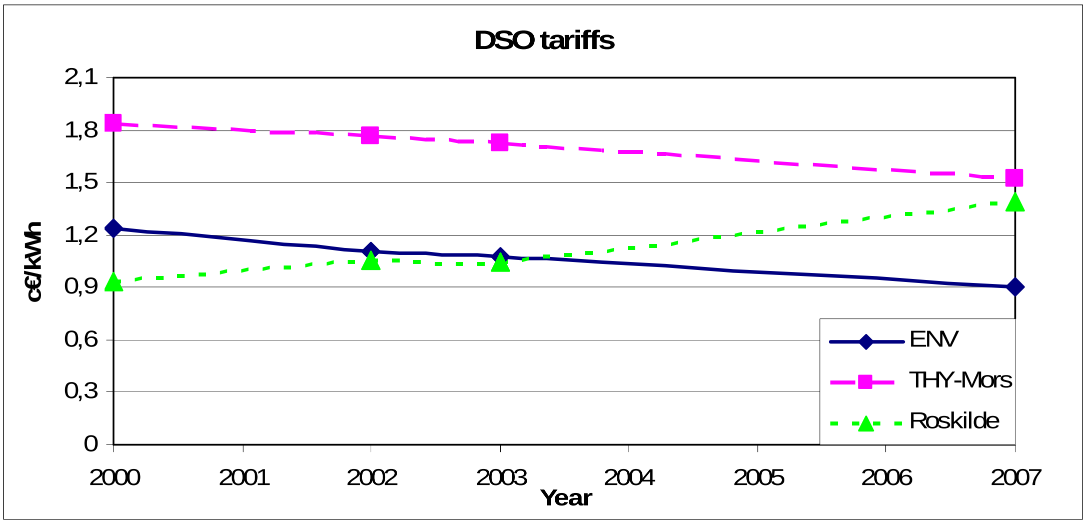

Figure 2.12 Distribution tariffs in three different areas (Prices Euro 2006); Source: (Danskenergi, 2007)

As it can be seen in figure 2.12, the grid tariffs vary wildly within the different areas. Roskilde Commune had to replace several overhead lines in the last years and therefore the price increased. But only ENV, a DSO in the North-West of Jutland did not have to change the grid very much since 2000 due to a strongly designed distribution grid in the mid nineties. The problem in the neighbor area THY-Mors was simply that they had to reinforce the grid each time a new wind turbine got connected and they did not look forward to that as much as ENV, therefore the distribution tariff is dramatically higher in their area. As ENV is one of the most cost efficient Distribution System Operators, they are allowed to make a little profit (Danskenergi, 2007).

Distribution grids were originally designed to take power from the high voltage grids and distribute the energy on a local smaller area at smaller voltage levels. Since the strong support of decentralized electricity production this aspect has changed and therefore some new challenges have raised problems. In former times the direction of the power flow was well determined and also the energy amount did not change within a short period. Connecting wind turbines and local CHP plants to the distribution grids means that the power flow can even reverse the direction and moreover the capacities of the distribution lines were too small.
One of the major problems the Distribution System Operators faced was the voltage control in their grids. Connecting a power generator to the grid leads to an increasing voltage level at the connection point but the DSO's have to keep the voltage level in a certain range. Some consumers can benefit of that, others would be disadvantaged. In order to manage this problem, new transformer stations with machine control equipment had to be built to regulate the power in the grid; this

caused additional costs. Another problem was the protection system, because power flow could change the direction therefore some protection instruments did not work properly and had to be replaced by new protection systems. All these investments the DSO had to make in order to manage the increasing share of decentralized generation in their grids (Fraser P., 2002).

Finally, the capacity and the extension of the distribution grid changed over time in order to connect all wind turbines and local CHP plants. These changes vary again very much in between the regions of Denmark. In areas with a high penetration of wind turbines, like the North-West part of Jutland, most changes are observed, whereas the grids in several other places did not change that much. Furthermore, it is to mention that costs caused by changing the grids protection systems are covered by the grid tariffs, whereas a major part of the investments in the extension and reinforcement of the distribution grid are covered by refunds from Energinet.dk, Denmark’s TSO. In this way the investments in the grid due to the increasing share of distributed generation are socialized and a fair pricing for the customers is guaranteed.

The influence of new grid-connected wind power is shown by researches of a selected Distribution System Operator in the North-West part of Jutland, which runs 161 wind turbines at a total capacity of 80,127 MW[1].
The wind turbines in that area got connected to the grid in mainly three steps. The first turbines were connected in the late eighties, followed by many turbines in the mid-nineties, and finally in 2000 the newest turbines were installed. In order to connect all these turbines to the 10 kV grid, the grid got reinforced and extended in the same periods. As is mentioned above, the foresighted planning of the distribution grid did not cause changes in the grid with each new wind turbine, it really point out the efficient planning of this DSO. Nevertheless a total extension of 75,181 km in the distribution grid was necessary, whereof all extensions are done by laying cables. Generally, four up to ten wind turbines were combined in one wind Park which got connected with the DSO with cables from 3x95mm ² AL up to 3x240mm ² AL depending on the power of the wind turbines. Further costs are caused by digging a trench for the cables and by the roll-out of the cables. All these costs are paid by the Distribution System Operator who is obliged to connect the wind parks to his grid.

[1] Expert interview at a local Distribution System Operator

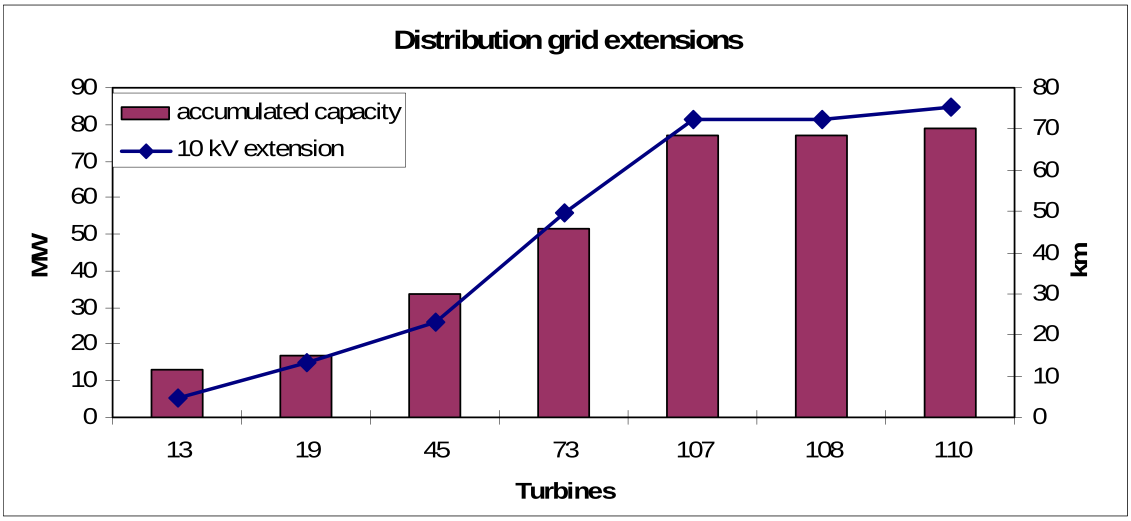

Figure 2.13 10kV grid extensions of the regarded area on the right scale and the installed wind power capacity on the left scale in the period between 1996 and 2002.

Figure 2.13 points out the grid extension of the local 10 kV gird in order to connect all 110 installed wind generators in the period between 1996 and 2002 to the grid. Grid extensions due to other reasons as connecting new households to the grid or other small-scale power plants are not considered in this figure. Moreover, it is illustrated that the first 50 wind turbines with a smaller capacity did not enlarge the grid as much as wind generators later installed. In this way, a strongly designed original grid was an advantage to install the first wind turbines without many changes in the distribution grid. Grid reinforcements are taken into consideration in figure 2.14 as well, as cables were substituted or extra cables were laid in order to connect the wind parks to the grid[2].

The other fact which is observed in the distribution grid deployment is, that over-head lines got substituted by cables and new grid extensions are mainly cables. Cables have a smaller statistic failure rate, which is mainly caused that the environmental impact is smaller on cables. Moreover, the total costs, including investment and O&M costs, are nearly the same although the investment costs of a cable amount to a higher percentage than that of an over-head line. Because the losses of cables are much smaller the operation costs equalize the higher investment costs. Furthermore, cables have hardly any visual impact and the magnetic impact above a cable is also smaller than below an over-head line because the single phases are laid closer together. Due to all these reasons, old over-head lines are constantly substituted by more powerful cables.

[2] Expert interview at a local Distribution System Operator

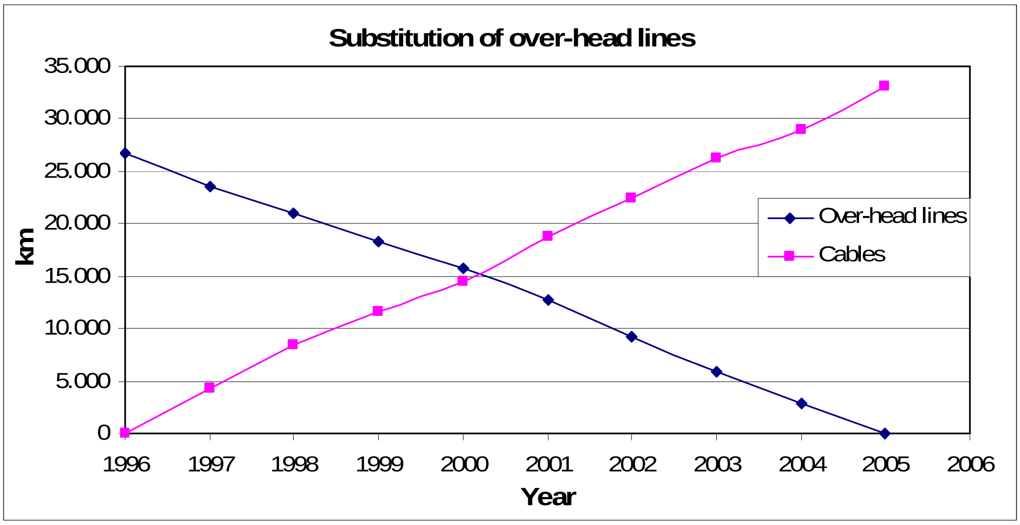

Figure 2.14 Substitution of overhead lines through cables in the distribution grids in Denmark

Figure 2.14 illustrates the decreasing amount of over-head lines in the Danish distribution grids, whereas a stronger increase in cables is registered in the same time. The differences are the 6.409 km of grid extension in the period between 1996 and 2005.

This grid extension required new transformer stations in the distribution grids too. Whereof in the period between 1996 and 2005 a total of 4.106 new transformers were installed with a total new capacity of 4,86 GVA, almost all of them belong to the voltage level up to 20kV. A major part of these transformers are to connect the wind turbines to the grid, but they are paid by the wind turbine owners. As figure 2.15 indicates between 2002 and 2003 more than thousand old transformer stations got substituted by new ones in order to provide reliable and more powerful distribution grids.

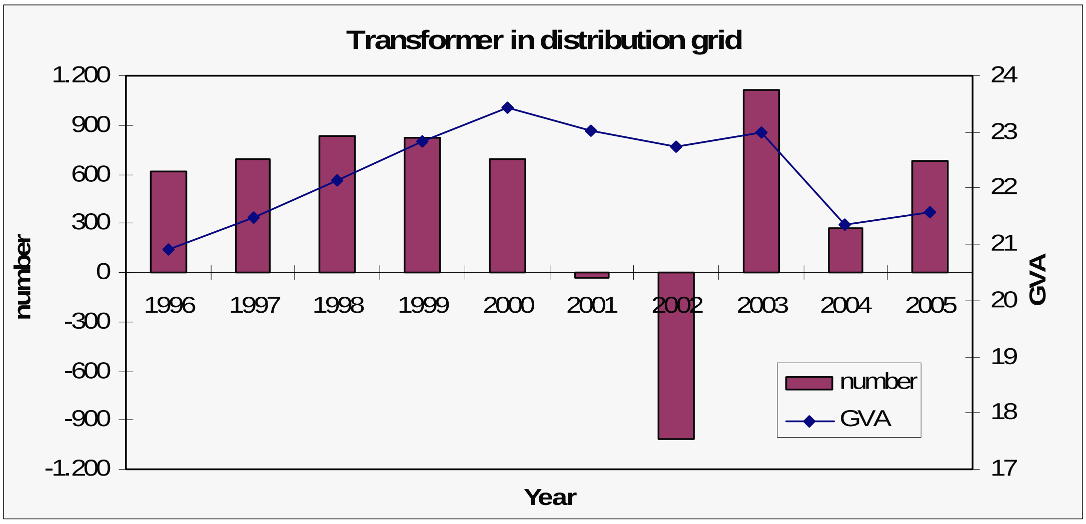

Figure 2.15 New installed transformer station in the Danish distribution grids on voltage levels up to 20 kV on the left scale and the total capacity of these transformers on the right scale

3. The Danish Electricity System – Integration of RES-E

The liberalization of the Danish Electricity Market started in 1998 based on the Electricity Supply Act from 1996 (Lawaetz H., 2005). The market was not opened for every participant at the same time. So in 1998 it was only opened for large customers and distribution companies with an annual trade of more than 100 GWh. Due to some corrections in the Electricity Supply Act on April 1st, 2000, the minimal annual trade was reduced to 10 GWh and afterwards on January 1st, 2001 it was reduced again to 1 GWh. The final opening of the whole Danish Electricity Market took place on January 1st, 2003.

This liberalization was a pre-condition to join the Nordic Power market NordPool. NordPool was founded in 1992 as the Norwegian market was opened and in 1996 as the Swedish market got liberalized too, it was the first international power exchange market. Since Denmark was operated by two System operators until 2005, the western part joined the NordPool market on July 1st, 1999 and the eastern part on October 1st, 2000.
Nowadays the organizational structure of the NordPool market has changed so that the physical day-ahead market ELSPOT became a separate company, while the NordPool Spot and the financial trades belong to the mother company NordPool. The NordPool Spot market is jointly owned by all four TSO's of the participating countries, Denmark, Norway, Sweden and Finland (Nordel, 2002)

3.1 Balancing of the Danish Electricity market

As Denmark participates in the Nordic power market, electricity production and consumption is always planned one day ahead to the operation. The actual production and consumption can deviate from the plan due to several reasons. On the one hand it is known since Kirchhoff that production and consumption in the whole system have to be every time the same. Therefore, the deviations have to be regulated; this is explained in the first subchapter. Furthermore, technical requirements and financial benefits of regulating power plants are discussed. Finally, the last subchapter highlights the special situation of balancing the high penetration of wind power on the Danish market.

3.1.1 Organizational structure of the balancing market

In order to regulate the deviations between the planned electricity production and consumption and the actual electricity situation in the whole grid, a complex system got introduced in the Nordic electricity market. This system manages the organizational interaction between generators, their traders and customers and their retailers, as well as between the different Balancing Responsible Companies, the TSO and the NOIS (Nordic Operation Information System). Due to the fact that every Scandinavian country uses the same system for regulating their market, the cheapest solution of balancing is achieved. The only exception is Jutland, which is connected to the UCTE grid and not to the Nordel grid; this is explained later on.

In Denmark 30 different Balancing Responsible Companies are operating. They are divided in groups belonging to the Demand side and the Generation side. These companies are commercial groups, of which one is a bank in London and another one is Vindenergi Denmark. On the other hand, every generator has its trader company, which sells the produced energy on the market and every customer has his retailer company which announces the required consumption for him. Therefore, the Balancing Responsible Companies main business is to collect the bids of production from their cooperative traders and the bids of consumption from their retailers. This collected information has to be sent to the Energinet.dk, the Danish TSO until 4 p.m. of the day before the operation. In most cases this data is sent to the TSO already in the morning, thus the Nordic power exchange market NordPool Spot closes at noon and no bids can be made afterwards.

With respect to the data of the several Balancing Responsible Companies, the TSO establishes an hourly action plan for the next day and decides which bids are accepted and which are declined. The decisions are made according to the prices of the bids, and a simple merit order is established by the TSO, claming that the cheapest are accepted first. Here it has to be mentioned that several older wind turbines are still regarded with zero production costs, due to legislations to promote renewable energy sources, and are therefore “primary dispatched”. The same occurs at small-scale CHP plants which run on the three-time tariff, a system offering different feed-in tariffs depending on the time of the day. Nevertheless, since in 2005 the new subsidy scheme was introduced, their real production costs are taken into account to establish the merit order (Hay C., 2007).
Since all bids for international electricity trading are made until noon, and until then also the TSO gets informed about the Available Transfer Capacity, allowances of bilateral trading can be done by the TSO until 4 p.m. These bilateral agreements are made directly between trader and retailer in the same area, but are nevertheless influenced by the spot market price according to the allowance of the TSO (Togeby M., et al., 2007)

The regulating power for the whole market is provided by the TSO. It has several measurement facilities in its grid to determine the actual frequency and the power flow. If the frequency derivate of the nominal frequency the TSO buys regulating power at the NOIS market (Nordic Operating Information System). NOIS is not a real market; it contains information of every generator in the Nordic system that provides regulative power in amount and price but only the national TSO's can buy there. These bids are made in steps of 15 minutes for the coming day, by the generators via the traders, the Balancing Responsible Companies and the TSO at NOIS. Therefore, NOIS presents a merit order of regulation power every 15 minutes, whereof in the case of Denmark, Energinet.dk buys the cheapest available regulating power in the whole Nordel grid. That means that in the case of a production excess in Denmark the frequency increases in the grid, the TSO buys, for example, down-regulation in Finland because at that moment it is the cheapest available down-regulation. Thus, the whole grid is balanced. This cheap regulation can only be done if there are no bottlenecks in the grid system; these would disable the power flow from the place of regulation-power production to the area where it is demanded. In such cases, the regulation power is bought from power plants which are located closer to the demand and where no bottlenecks are in between, but which have higher production costs.

Furthermore, regulation power is bought on the ELBAS market, which opens at 4 p.m. and closes an hour ahead the operating hour. On this market the Balancing Responsible Companies directly buy their required regulation power for their clients only. Thus, the market closing an hour before the operating hour is an advantage for wind production, but is still does not regulate the market exactly. The rest deviation has to be regulated at NOIS, therefore only a few Balancing Responsible Companies trade on ELBAS (Togeby M., 2007).

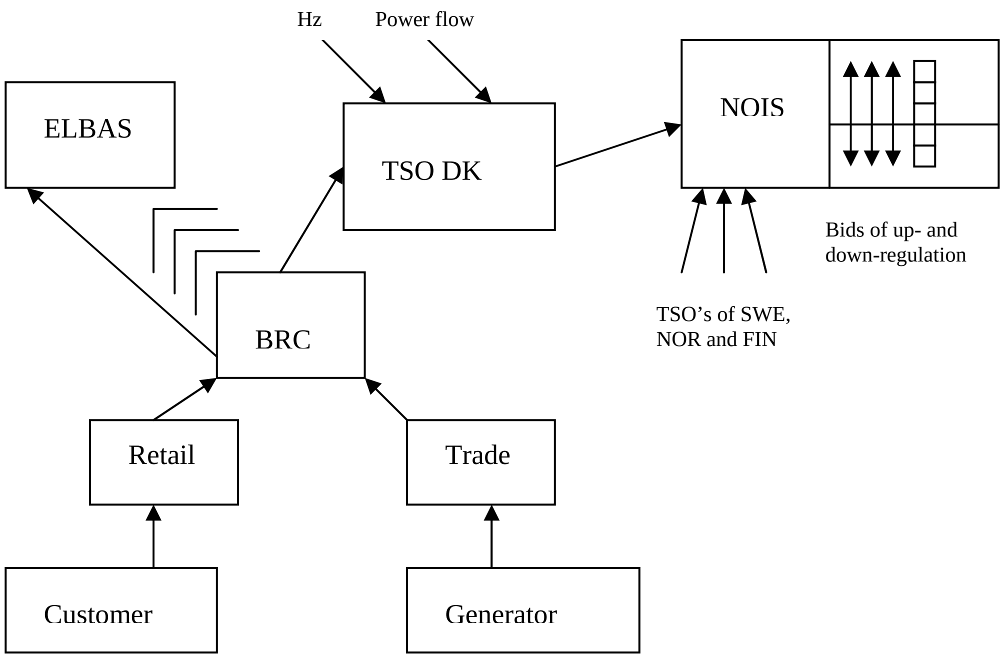

Figure 3.1 The Nordic power regulating scheme and its participants. TSO...Transmission System Operator, NOIS...Nordic Operation Information System, BRC...Balancing Responsible Company, ELBAS...power market at NordPool (Togeby, M.; 2007)

Since the total of the required regulation power is only known after the time of operation, the TSO calculates the accumulated expenses for regulation. Furthermore, the TSO knows who caused which amount of regulating power and therefore the invoices are sent to the Balancing Responsible Companies the day after operation. The Balancing Responsible Companies either charge their retailers and traders a certain fee each year or charge them once a month the actual invoice for balancing them. The Nordic market is very big and has a lot of hydro power which responds fastly and has low production costs. The average regulation costs amounted 0,31 c€/kWh in 2006.

The difference in balancing the power market between Zealand (East) and Jutland (West) is that Jutland is connected to the UCTE grid whereas it still trades energy on the NordPool Sport market. That means it is part of the Nordic market but the grid belongs to the UCTE and therefore it has to regulate the market itself. The UCTE members expect Jutland to operate a fully regulated power market.

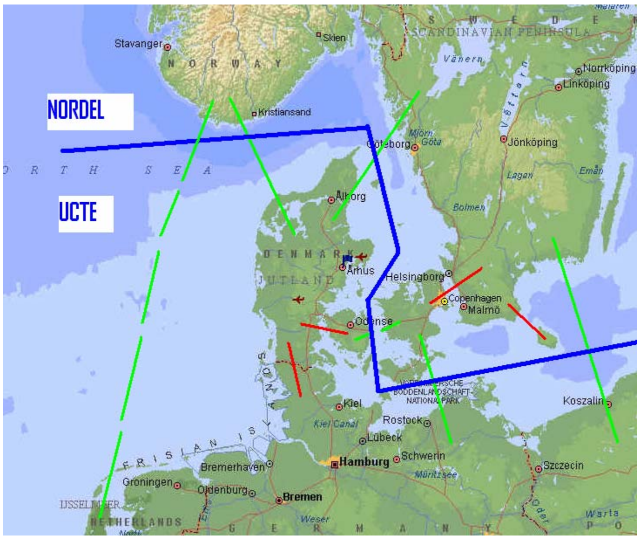

Figure 3.2 Border line between UCTE grid and Nordel grid, Showing DC connection lines crossing the border of the UCTE grid and the Nordel grid and AC connection lines within the systems, doted lines are commissioned but not built yet; Source: (Togeby, M.; 2007)

As shown in figure 3.2, Jutland is only connected via DC cables to the Nordic market. From the technical point of view it would be possible to transmit regulating power also via DC cables, but due to the fact that DC lines are very expensive, they are mostly congested with the permanent energy trade that is more profitable for their owner, the TSO. Therefore, Jutland has his own balancing power plants, which makes the balancing in their market more expensive, because they use mostly thermal power plants for balancing.
In order to prevent that customers in Jutland have to pay a higher price for balancing, the balancing costs are covered by the generators, thus most of the regulative power in Jutland is caused by the many windmills they operate. Since it is easier to predict

the output of many wind turbines compared to only one turbine, most wind turbine owners have joined groups for trading their energy (Togeby M., 2007).

3.1.2 Requirements for and benefits of regulative power providers

Providing regulative power has advantages and disadvantages. In order to be able to provide regulative power, the power plant cannot run on full production to be able of an up-regulation, which results in a smaller income. On the other hand different grants are paid only for being in the stand-by mode, but for the allowance to provide regulative power several technical requirements have to be fulfilled.

The grants a power plant in Denmark could receive in the stand-by mode were almost 27.000 Euro/MW[3] annually until 2005, but an up- and down-regulation of 150 MW had to be possible all over the year. This annual grant of more than four million Euros made it really lucrative to provide regulative power whenever there was a need for. The only limitation were the transmission lines to Sweden; In Sweden a power plant could not receive any grants at all for regulative power because the high penetration of hydro power could provide enough back-up power within a few minutes. Moreover, the hydro power did not release any CO2 emissions and provided the required power at a cheaper price.
Nowadays, in Denmark every power plant announces its possible regulative power plus price in hourly steps. Furthermore, it is not obligatory anymore to provide at least 150 MW. This change made it possible that small-scale CHP plants can provide regulative power too. The advantage is, that regulative power production is wider spread all over the country and also became environmentally cleaner, thus it is not only provided by big coal-fired plants. In addition, the amount of required regulative power for the next day is much easier to predict than for a whole year. All these facts reduced the total amount of paid grants, although the annual grant increased up to 65.000 Euro/MW and more.

Even though it is very lucrative to provide regulative power, three technical requirements have to be fulfilled.
Firstly, an amount of at least 10 MW has to be provided. Therefore, small-scale CHP plants are joining into groups to exceed 10 MW, but the price of the provided power is determined by the most expensive participant of this group, which might make their bid uncompetitive.
Secondly, power plants have to be equipped with an online metering system for the invoice procedure. These systems are very expensive and in small-scale CHP plants only useful for the aspect of regulative power; thus, the usual operating does not require the online metering. An ongoing research is conducted to point out that these

[3] 1 DKK = 0,13441 EUR; January 1st, 2006 http://www.exchangerate.com/

online metering services are only barriers for small-scale plants to take part at the regulating market.
Finally, only power plants can provide regulative power, which are able to deliver the required energy into the grid within maximal 15 minutes. This excludes some potential big plants like nuclear power (Togeby M., 2007).

3.1.3 Principles in balancing wind energy

The need of physically balancing the electricity market arises already from the past, due to an unpredictable demand of electricity. Thus, balancing requirements are divided into three different steps of time scales. Primary reserve handles the balancing in second to minute time of operation, whereas secondary reserve operates in the ten minutes to one hour time scale. Finally, the tertiary reserve, which is also called the long-term reserve, balances the market afterwards.
Wind power does not have a big influence on primary reserves, but most of the required balancing power is provided by secondary reserves because fast variations in total wind power output occur randomly.

Furthermore, as the income for wind power is regulated depending on the year of erection, also the balancing system is regulated so. Table 3.1 gives an overview on how the different turbines regulate their balance power.

Table 3.1 Balancing regulation for wind turbines in Denmark; Source (Hay, C.; 2007)

Installed before 2003	These are the turbines which still receive feed-in tariffs from the TSO. But in 2013 the last turbines will be on the market conditions and then this kind of balancing does not exist any longer. The TSO makes the announcement for these wind turbines at NordPool, handles their balancing and also pays it.
Installed before 2003 but not longer on the old pricing system	Turbine owners are responsible for the balancing on their own but they can buy the balance power from the TSO, who makes the announcements at NordPool for them. Nevertheless, the owners pay the balancing themselves, plus an administration fee to the TSO
Installed after 2003	They have to make the announcement at NordPool themselves and pay their own balancing. Most private owners have joined a company for balancing, such as Vindenergi Denmark.

In table 3.1 it is mentioned that the TSO is responsible for the balancing of older wind turbines. That means that in this case one department of the TSO works also as Balancing Responsible Company.

Several studies have been done and are still ongoing to identify the impact of wind power on the required capacity of back-up power. There is no need to provide as much back-up power as wind power capacity is installed. A general result of these studies was that even in extreme cases the output of distributed wind turbines does not change more than ten percent. However, as the penetration of wind power in Denmark is much higher than the average in the EU, the impact on reserve capacity exceeds up to 25 percent of installed wind capacity in single stormy cases.

In order to reduce the requirements for balancing power, wind forecast tools are improved slightly over time. Wind power producers make their bid on the day before operation at noon at NordPool. If wind power could better be forecasted for the next 12 to 36 hours, the demand of balancing power will decrease and moreover, the balancing costs too.
Not only turbine owners would benefit from a better wind forecast tool. Also the Distribution System operators could predict their power flows more exactly, which would cause less network operation costs. A further advantage might be that investments in distribution grid reinforcements are avoided due to better known power flows. The interests in better wind forecast tools for the Transmission system operator are the same as for the DSO’s and additionally bottlenecks in the transmission lines might be avoided when the power flows are better known. Finally, if wind energy is used in the distribution gird where it is connected to, no power transmission and thus no costs for the TSO would occur (van Hulle F., 2005).

3.2 Regulatory issues in Denmark

Thus, renewable electricity generation is in many cases not yet economically feasible, Denmark developed several strategies in order to promote RES-E. The first subchapter points out the regulatory interventions in renewable energy generation, whereas the second subchapter addresses the criteria of grid connection of renewable electricity generators.

3.2.1 Regulatory intervention to promote RES-E

Since Denmark has the highest penetration of renewable energy use in the EU, it will be discussed which legislations and decisions have lead to that.
The first steps to change the energy production were already taken in 1973, after the oil crises in the Middle East when Denmark was an oil net importer. Since that time

several action plans to support electricity production by renewable sources got introduced. Therefore, in 1990 the ambitious Danish energy minister Jens Bilgrav launched the Energy Action plan (Energy 2000) with the target of reducing the CO2 emission by 20 percent between 1988 and 2005. As most of these aims were reached in 1996, the energy and environmental minister Svend Auken updated the strategy with the Energy Action plan (Energy 21) which aimed a further greenhouse gas reduction of 50 percent until 2030. Finally, in March 2000 a follow-up plan was introduced called (Climate 2012) which aimed to establish programs to analyze the development of the Kyoto mechanism and submits a new action plan for the transport sector as well.

This integration of environmental policies evolved to a substantial change of the Danish power sector. It reduced CO2 emission rapidly and even create overcapacities. The overcapacities were also caused by the state by setting wind power and local small-scale CHP plants on a priority dispatched status. That means that these power production methods are regarded as free of charge and therefore they were the first in the merit order. The real production costs were covered by subsidies (Olesen, G. B.; 2003)

These subsidy schemes varied over the years and are discussed in detail in the following chapters; only a short overview is given here.
In the early nineties investment grants were paid up to 30 percent of the total investment costs for small-scale CHP plants as well as for wind turbines, to introduce these electricity production methods to the market. Afterwards, only production-related subsidies were eligible, depending on the time of grid connection and the power size of the plant. Such subsidies have been fixed feed-in tariffs for wind turbines and local CHP plants using renewable energy sources for a certain period or a determined amount of full-load hours. Other small-scale CHP plants were subsidized on a three-time tariff, where the income was divided into three levels depending on the time of day. The total amount of subsidies paid to the producers was covered by the Public Service Obligations (PSO) which the TSO received from the end-consumers.

In order to stabilize the electricity costs for the end-consumer a bit, a fee for supporting central large-scale plants was abolished in 1999. This fee was a saving of central power producers for future investments in central power plants.
Finally, a general subsidy of 1,34 c€/kWh for renewable energy production was eligible for all producers. These 1,34 c€/kWh were paid by the end-consumers as a CO2 tax and if power plants produced energy environmentally friendly, they received that money. Considered as environmentally friendly are all renewable energy sources

as well as natural gas. Furthermore, in Denmark no energy taxes are added to energy produced on biomass.

All the different financial subsidies are regulated by laws and bye-laws to promote renewable energy sources. Almost every bye-law of the different subsidy schemes refers to the Danish Electricity Act of 1999, which got updated several times. The actual Act on Electricity Supply number 286 dates from April 20th, 2005 (Lawaetz, H; 2007) and is a consolidation of the Act number 151 from March 10th, 2003 and further amendments. Within that Act on Electricity Supply, the actual subsidies for wind turbines are available at the paragraphs §56 until §56d whereas the paragraphs §57 and §58 represent the subsidy scheme for small-scale CHP plants in Denmark.

3.2.2 Regulatory intervention in RES-E grid connection

In order to promote renewable energy sources, incentives for investors cannot only concern the production costs. The grid connection costs of new power plants have an important impact on the total investment costs and therefore different methods how to implement these costs have been considered by the Danish government. Since only small-scale CHP plants and onshore wind turbines are considered, almost every power plant is connected to the distribution grid and does not have an influence on the transmission grid configuration.

Primarily, there are two different approaches how to include a new power plant in the grid. At the first approach, the Deep Costs Approach, the total costs for digging trenches and laying cables from the power plant to the grid node where it gets connected have to be covered by the power plant owners. On the other hand, at the Shallow Costs Approach, only the costs from the power plant to the closest 10 kV node have to be covered by the owners. It does not matter where the power plant is physically connected to the grid, the owners only cover the costs to this virtual connection point and the rest is paid by the Distribution System Operators.
Denmark implemented the second approach, the so called Shallow Approach, which is much more favorable for investors of renewable energies. The investment costs are smaller and therefore a shorter pay-back time is achieved. The bigger amount of grid connection costs is covered by the local Distribution System Operators (DSO) which are applied to connect every renewable energy producer to their grid. This agreement is determined in the Act on Electricity Supply of 2005 in paragraph §8 and §68.

Secondly, Denmark decided by law how to socialize the costs the different DSO’s have to pay. Due to the fact that most wind turbines are installed in the North-West part of Denmark, it would be unsocial to spread the connection costs of new power plants only in their areas by increasing the local grid tariffs. Therefore, the bye-law NOTAT 02-001e (Koch, J.; 2007) informs on how to socialize these costs. This is explained in the further chapters and here only discussed briefly.

As the DSO has to connect every new renewable electricity producer to his distribution grid, he has to cover all the costs for digging the trench, laying the cable and setting up the 60kV transformer station. On the other hand, the TSO calculates these expenses and it refunds the calculated amount to the local DSO without considering the real expenses. The calculation is carried out by using the model defined in the bye-law. The difference between the real expenses and the refunded costs are covered by the distribution grid tariffs. Distribution System Operators are non-profit companies and therefore the grid tariffs are adjusted every three months, depending on the expenses and incomes of the company.

4. Economics of on-shore wind power in Demark

This chapter takes into account all economic parts of wind power generation. Wind power plays an important role in the electricity supply system of Denmark. Within this chapter, only onshore wind power production is regarded; offshore wind parks are not considered as being distributed generation, due to their high capacity and their connection to the transmission grid.

The first part of this chapter shows the calculated generation costs of different wind turbines and their deployment and different influences over the last years. Additionally, the different kinds of incomes are explained as well as an example showing the economics of one wind turbine placed on the coastal side of Denmark.
Furthermore, the balancing of wind energy and the costs caused by a volatile energy source such as wind is explained. The influence of wind energy on the spot market prices is discussed as well.
Finally, the last part highlights the development in the distribution grid, where most of the windmills are connected and explains the different legislations for connecting them to the grid. Additional examples and diagrams show which costs the grid changing caused and how the grid tariffs for the end consumer reflect those costs.

4.1 Generation costs of wind power

The costs of wind energy are influenced by different parameters. The first subchapter takes into account the influence of manufacturing and financial parameters. Moreover, the levelized generating costs of the past twenty years are calculated.
Based on these results, the second subchapter shows the learning effect in manufacturing and operating wind mills. An estimated forecast of wind generation costs within the next two decades is given as well.
Thus, wind energy generation is not economically feasible yet. The different subsidy schemes are explained in the next subchapter. A case study of a 600 kW wind turbine demonstrates, how the subsidies act, and compares the generation costs to the incomes of the sold energy.
Finally, the costs caused by balancing the power market due to the unpredictable wind energy output are pointed out in the last subchapter.

4.1.1 Calculation of levelized generation costs

Production costs of any wind turbine are difficult to find and were not officially available. A good approach of real production costs are levelized production costs, calculated by investment costs, discount rate, O&M costs (Operating and Maintaining) and full-load hours as (Haas, R.; 2005),

$$c_{el} = \frac{\alpha * I}{t} + c_{O\&M}$$

whereas α is calculated as

$$\alpha = \frac{(r+i)*(1+r+i)^n}{(1+r+i)^n - 1}.$$

c_{el}	levelized generation costs [EUR/kWh]
α	Annuity factor
I	Investment cost [EUR/kW]
t	Full-load hours [kWh/kW]
$c_{O\&M}$	annual O&M costs
r	risk rate [%]
i	discount rate [%]
n	amortization period [a]

These identified levelized production costs are very sensitive in variation of the discount rate and the amortization period; this will be discussed and illustrated in thediagrams below. The parameter investment cost contains not only the ex-work costs of a turbine. It also includes the costs of the foundation, the electrical installation, the ground, the control system and the part of the grid connection the wind turbine owner has to pay. Nevertheless, the dominant part of the investment in a wind turbine is the turbine itself. In 1985, 75 percent of the total investment costs were caused by the turbine and the rest was divided into other parts, whereof the grid connection amounted to eleven percent. Since there are many wind turbines installed all over Denmark, the distribution grid got extended from the local Distribution System Operators, and the distance to the next connection point for newer windmills decreased. Due to this, the percentage of grid connection in investment costs reduced to six percent and the ex-work costs increased to 83 percent in 2004.
Furthermore, the declining electricity production costs are achieved due to learning effects by using wind turbines. This means, that due to running and operating wind turbines the O&M costs decreased constantly.

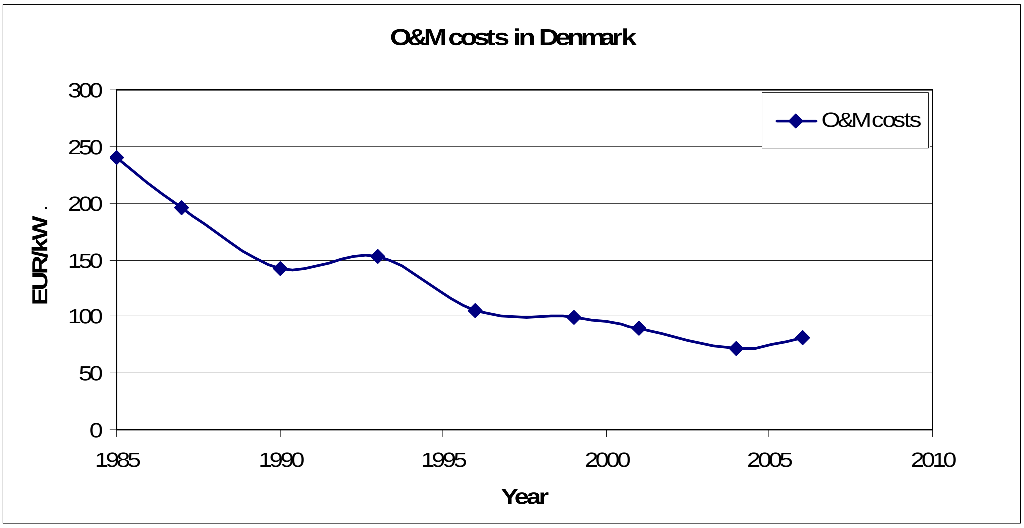

Figure 4.1 Deployment of O&M costs in 2004 prices in EUR/kW

The figure 4.1 illustrates the decreasing O&M costs over the last two centuries in prices of 2006. Since there were a lot of windmills erected in the mid-nineties, O&M costs declined rapidly in this period. The rise in 2006 derives from higher maintenance costs of the new 2000 MW turbines. Mostly, O&M costs are published in percent of the investment costs and amount in 2006 around seven percent, whereof one percent is the insurance payment of the turbine. Moreover, these seven percent of investment costs are not constant over the entire lifetime of the turbine. When the O&M costs amount to only three percent in the first years, they increase up to eleven percent after sixteen years in operation.

On the one hand, falling O&M costs supported the decreasing production costs of wind energy, but on the other hand, the increasing full-load hours influenced the output of a wind turbine enormously and improved the energy efficiency. Full-load hours increased constantly with the development at the technology. A full-load hour is defined as one produced kilowatt-hour per one kilowatt installed capacity. The full-load hours are depending widely on the location of erection of the wind turbine and on the date of installing it. The deployment of full-load hours achieved by Danish wind turbine producers can be seen in figure 4.2. The illustrated growth is achieved due to technical improvements of turbines.

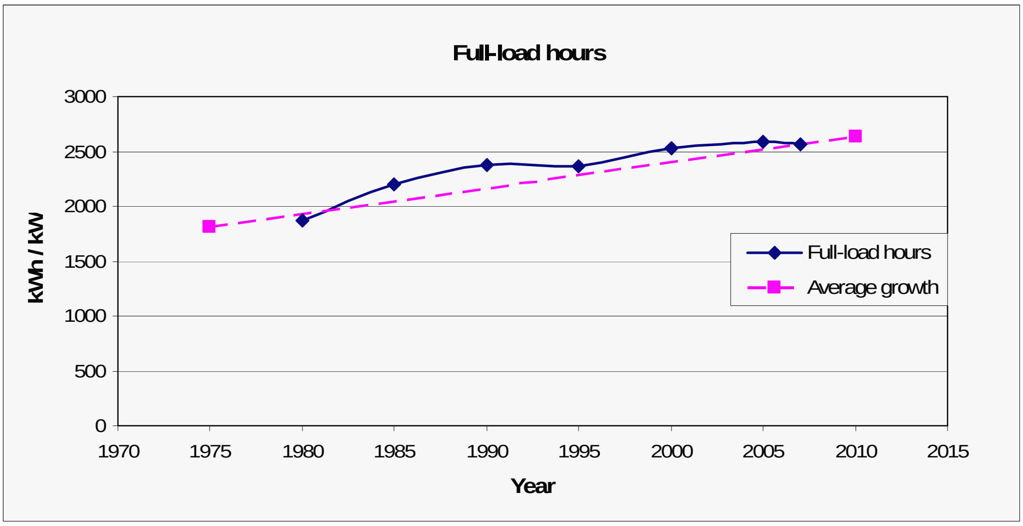

Figure 4.2 Full-load hours of Danish turbine manufactories (Source: Dannemand, A.P.; 2004))

Moreover, countries like Denmark, with a long shore at the North Sea have high wind speeds all over the year, which additionally enlarge the energy output compared to wind turbines built up in the countryside. As it is demonstrated in figure 4.2, full-load hours increased by almost 700 kWh/kW, amounting to more than 27 percent. Considering 2 MW turbines which are recently the most common installed in Denmark, results in an additional output of approximately 1400 MWh of renewable energy. Generally, it can be said that with each new type of wind turbines the full-load hours increased but they still depend on the erection place and the wind speed. This is the reason why for calculating the levelized production costs only average full-load hours are used, and so they are only good estimates but are not reflecting the real production costs.

An investor of an item is always most interested in the pay-back time of it. This pay-back time depends mainly on the above mentioned aspects, but an easy toll to influence is the discount rate. All the calculations are done by using a discount rate of 6,5 percent (Morthorst, P:E.; 2007). Figure 4.3 visualizes the difference in production costs with an additional 3,5 percent rate, the so called risk premium. The risk premium is chosen by investors in order to guarantee that they get their investments back in time, even if the wind turbine cannot produce at the predicted full-load hours due to natural influences.

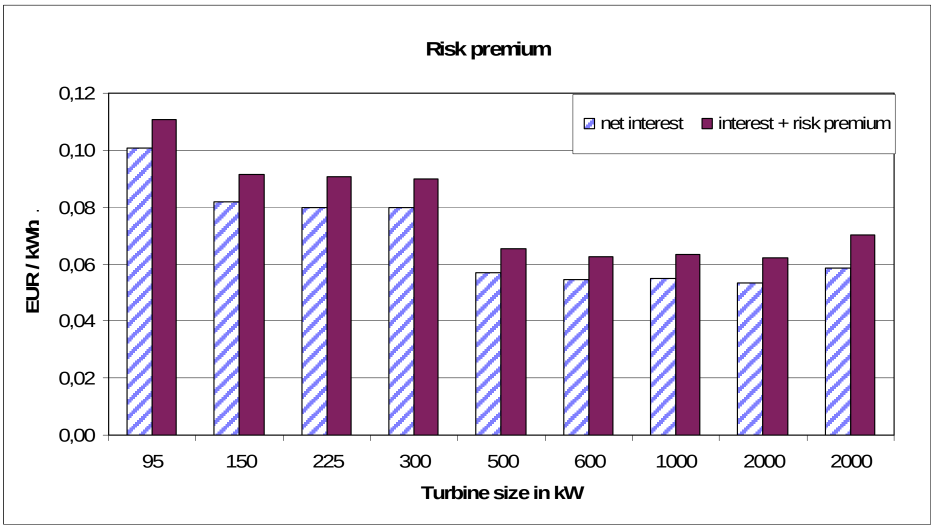

Figure 4.3 Levelized production costs compared with and without risk premium; Source (Morthorst, P.E.; 2007)

In figure 4.3 are two calculated costs of a 2 MW wind turbine, whereof the left bars of the 2 MW turbine reflect a wind turbine erected in 2004, and the right bar shows turbines built in 2006. Higher production costs in 2006 are caused by two main reasons. Firstly, the price of steel for the tower of the turbine increased due to a high demand of the Chinese industry, which grew rapidly. Therefore, the investment costs grew from 1000 EUR/kW up to almost 1150 EUR/kW, and as it is mentioned above, nowadays ex-work costs cover almost 85 percent of the total investment costs. Furthermore, a lot of new technical requirements got obligatory in order to connect a wind turbine to the distribution grid. Such requirements are, for instance, an active power control, a frequency control or a voltage control. In order to take into account the economic feasibility, there are grid codes which describe the necessary technical equipment a turbine must be provided with. The grid codes for the distribution grid can vary from one grid to the other, depending on local situation in the grid and the influence a windmill has (van Hulle, F.; 2005).

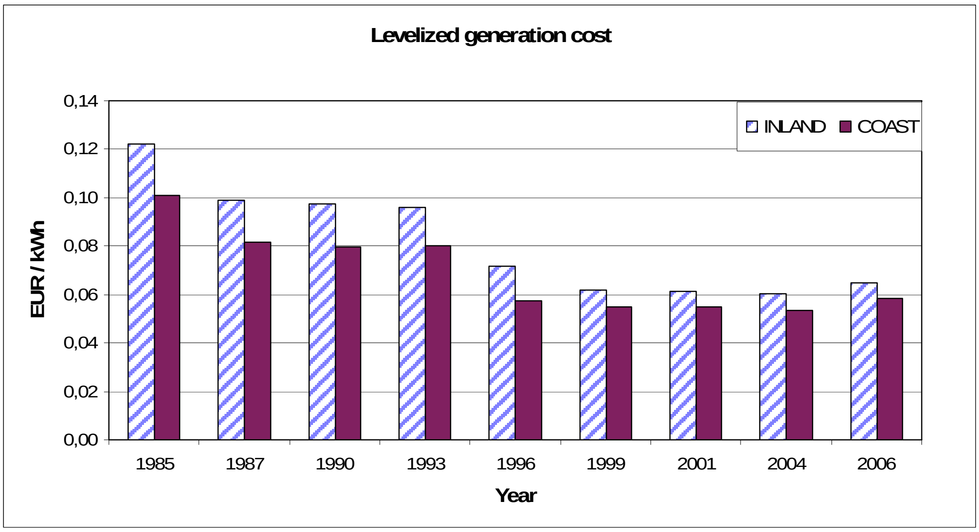

Figure 4.4 Levelized electricity generation costs within the past 20 years in Euro 2006 prices; Source (Morthorst, P.E.; 2007)

In figure 4.4, the calculated levelized production costs are shown in prices of Euro 2006. The hatched bars show the costs for wind turbines which are located in the countryside and have therefore less full-load hours. The fulfilled bars express the energy production cost in coastal areas where, the wind blows more often and with higher speeds. Most of them are erected in the north-west part of the country, due to better wind conditions.

4.1.2 Experience curves in production costs

The reduction of electricity generation costs is achieved due to several aspects which were mentioned before, as well as due to running and operating windmills. It is to distinguish between "learning by doing" and "learning by using". All cost reductions due to technical improvements are smaller than the total cost reduction which was achieved by improving the wind turbines in laboratories and run them on the sites. The latter effect is called "learning by using" and is shown in an experience curve further on.

An experience curve is calculated by (Neij, L.; et al., 2003):

$$C_{CUM} = C_0 * Cum^b$$

$$b = \frac{\log C_{CUM} - \log C_0}{\log Cum}$$

$$PR = 2^b \qquad LR = 1 - 2^b$$

C_{CUM}	cost per unit	b	experience index
C_0	cost of the first produced unit	PR	Progress rate
Cum	Cumulative production	LR	Learning rate

The learning rate LR indicates the cost reduction for the calculated item if the cumulative production has doubled up. A learning rate of 0,15 means a cost reduction of 15 percent each double amount of cumulative production.
Generally, the learning effect can be divided into three parts. First is the innovation in one size of the turbine. In this period, the machine size does not change, only some parts of the turbine, as for instance the gearbox, can be replaced through another gearbox from a different manufactory. This part of learning causes the smallest learning rate. Secondly, an up-scaling in a platform occurs. A platform is the whole system in which the turbine, the gearbox etc is mounted. In this phase of innovation a 500 kW turbine is replaced by a 750 kW turbine. Moreover, the first turbine in a new platform is always built with a higher respect to the mechanical strength than after some renovations in a platform. Finally, the last part of innovation takes place in the introduction of a new and bigger platform with a new turbine size. This turbine is constructed with a high respect to mechanical strictness but is not as highly sophisticated as it becomes in the end of the second phase (Dannemand , A.P.; 2004).

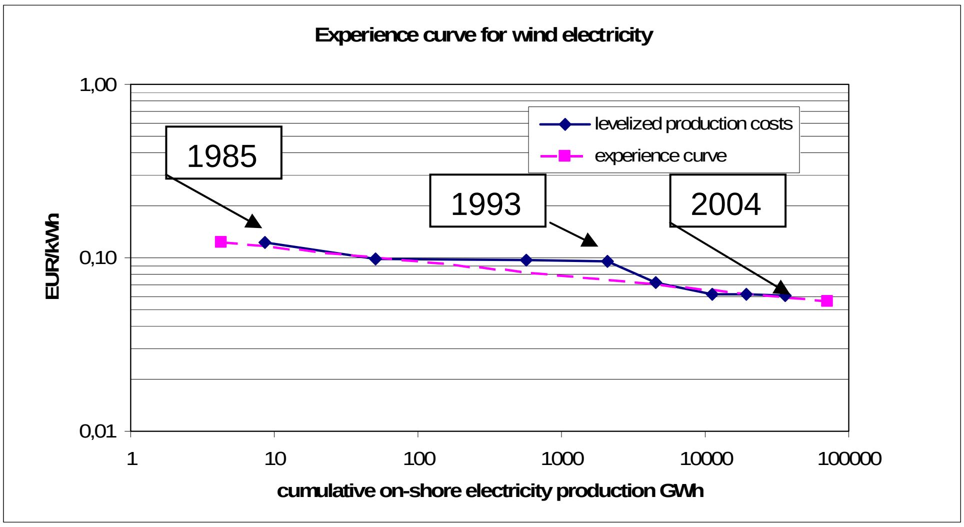

Figure 4.5 Experience curve of electricity production costs of on-shore, costal placed windmills in Denmark at a discount rate of 6,5 % and with a LR of 12,84%

Figure 4.5 demonstrates the experience which has been achieved through running and operating wind turbines in almost twenty years in Denmark. The Learning rate LR is calculated with respect to the formulas mentioned above, and results in LR = 12,84 percent. Every double amount of produced energy [TWh] of onshore wind turbines in Denmark, the production costs decreased by 12,84 percent. Until nowadays, the amount of produced energy doubled approximately every third year. This can not be expected for the future because almost all economically feasible locations are already occupied by windmills. Further expansion in onshore wind production will mostly take place through replacement of newer, more powerful wind turbines. Thus, the time span for doubling the amount of produced energy from wind turbines is expected to take between five and ten years.

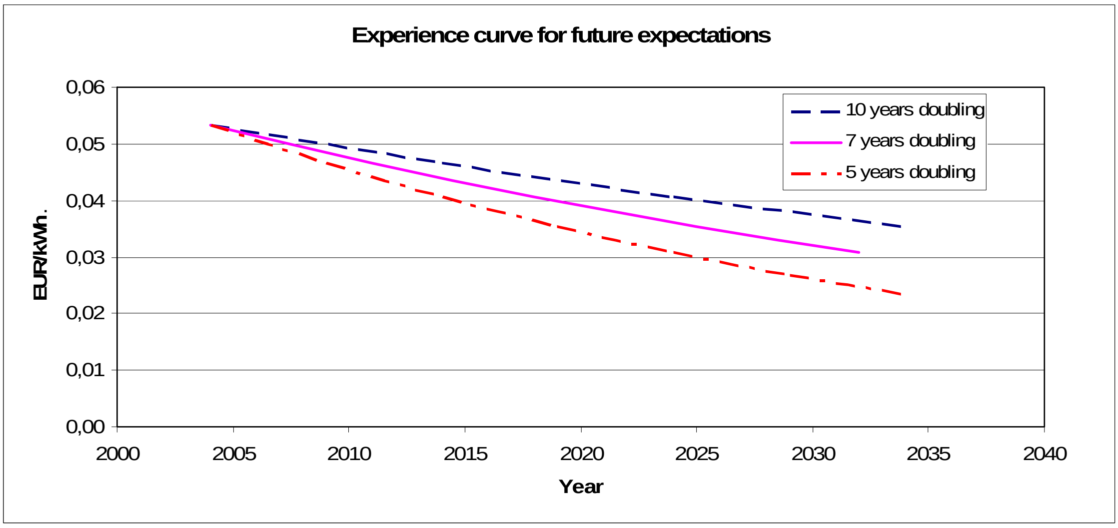

Figure 4.6 Experience expectations determined with LR =12,84% and vary periods of doubling the amount of produced energy

According to figure 4.6 the above mentioned electricity production costs will vary between 2,26 c€/kWh and 3,35 c€/kWh in 2030 depending on the development of wind energy production. In this calculation a discount rate of 6,5 percent and a turbine coastal placed is taken into account (Morthorst, P.E.; 2007).

4.1.3 Incomes of wind energy production

Almost all wind turbine owners sell their produced electricity on the market. The price per kWh in Denmark is calculated by the Nordic electricity market, NordPool. Every producer or company who sells the electricity has to make a bid at NordPool each day at noon, meaning how much energy they will generate within the next day. This system is equal for every producer, so the energy source is not taken into account. NordPool is then calculating the merit order and the result is price per produced kWh.

Thus, wind turbines have still higher electricity production costs than conventional central power plants; different kinds of subsidies are given to the producers. The rules for subsidies have changed within the last years. In the beginning, very good subsidies were paid to the owners in order to provide incentives to invest in wind turbines. Nowadays, a high penetration is reached and there are not so many possibilities left for erecting new turbines. So, the amount of subsidies decreased and the kind of subsidies changed.

The following table 4.1 shows how in the Danish system the subsidies for wind electricity production are distinguished and which amount is paid to the turbine owners.

Table 4.1 Income of on-shore wind turbines in Denmark in 2006 prices; Source: Danish Electricity Supply Act $56, $56a, $56b, §56c and §56d

Turbines connected to the grid in:	Amount and kind of subsidies according to the law Prices in c€ 2006
until the end of 1999	Fixed feed-in tariff of 8,06 c/kWh for the allowance of full-load hours (25.000 hours for turbines up to 200kW, 15.000 hours from 201-599kW and 12.000 hours over 600kW). Afterwards, a tariff of 5,78 c/kWh was paid until the turbine was 10 years old. Finally, the turbine was on the market price plus a premium of 1,34 c/kWh until it was 20 years old.
from 2000 until 2002	A fixed feed-in tariff of 5,78 c/kWh was eligible for 22.000 full-load hours for every turbine size. If the full-load hours were used up, a premium of 1,34 c/kWh was paid until the turbine was 20 years old. The premium was regulated in accordance to the market price that the total did not exceed 4,84 c/kWh.
from 2003 until 2004	Turbine owners were selling the electricity on the market, but a premium of 1,34 c/kWh was paid until the turbine was 20 years old. Again, a total of premium and market price was not allowed to exceed 4,84 c/kWh, otherwise the premium was reduced.
from January, 1st 2005	Turbine owners are responsible to sell the electricity on the market and receive a premium of 1,34 c/kWh within the first 20 years. This premium does not depend on the total price the turbine owner receives per kWh.
Household turbines	Turbines with a capacity up to 25 kW are considered as household turbines and they are connected to the grid through the consumption installation. For their produced surplus they receive a total amount of 8,06 c/kWh.
financed by utilities	Turbines connected to the grid before the end of 1999 have to sell their electricity on the market at the spot market price. Turbines connected from January, 1st 2000 are eligible for a total payment of 5,78 c/kWh for ten years. Afterwards they receive a premium of 1,34 c/kWh whereof the total income must not exceed 4,84 c/kWh.

All these subsidies and premiums which are mentioned in table 4.1 are paid by the Transmission System Operator to each single energy producer. The TSO receives a so called Public Service Obligation (PSO) from each electricity consumer in order to pay the subsidies to the producers. This PSO is introduced according to the Electricity Supply Act 1999, which says that every costumer is obliged to buy a certain amount of renewable energy sources.

The following case study on a wind turbine compares the expenses for a wind turbine to the incomes of it. The calculations are made for a 600 kW wind turbine which was erected in the North of Copenhagen. It got connected to the 10 kV-grid on August, 11th 1996 and the turbine was manufactured by BonusEnergy A/S. Furthermore, it is known that the hub height is 50 meters and the diameter of the blades counts 44 meters.
All the necessary data input is provided by Danish Energy Authority and by the Risoe National Laboratory[4]. It gives a good overview on how the rules for subsidies are implemented and what could be achieved by all these different kinds of subsidies. All costs and incomes are pointed out in Euro 2006, whereby the inflation for the coming years is estimated due to a constant inflation of 1,8 percent during the last ten years. Furthermore, the produced kWh are only estimated for the period from February 2007 until the calculation ends in 2015. The total investment costs are calculated at a discount rate of 6,5 percent and an amortization period of 20 years is taken into account.

Table 4.2 Case study on a 600 kW wind turbine in the North of Copenhagen

Year	installation costs	O&M costs	Deflator inflation	installation costs	O&M costs	produced electricity	produced electricity	produced electricity	used full-load hours
	DKK	DKK	1,8077%	EUR 2006	EUR 2006	kWh	kWh	kWh	kWh/kW
1996	251.639	60.516	0,16653	41.905	10.078	434.848			724,7
1997	251.639	121.032	0,16327	41.085	19.761	1.008.401			2.405,4
1998	251.639	121.032	0,16013	40.295	19.381	1.137.401			4.301,1
1999	251.639	161.376	0,15815	39.797	25.522	1.027.001			6.012,8
2000	251.639	161.376	0,15098	37.992	24.365	1.047.869			7.759,2
2001	251.639	201.720	0,14738	37.087	29.729	1.006.073			9.436,0
2002	251.639	201.720	0,14519	36.535	29.288	1.154.012			11.359,3
2003	251.639	201.720	0,14197	35.725	28.638	384.395	605.624		13.009,4
2004	251.639	242.064	0,13913	35.011	33.678		1.053.201		14.764,7
2005	251.639	242.064	0,13684	34.434	33.124		990.418		16.415,4
2006	251.639	242.064	0,13441	33.823	32.536		489.401	382.800	17.869,1
2007	251.639	242.064	0,13311	33.496	32.221			987.441	19.514,8
2008	251.639	242.064	0,12981	32.665	31.422			1.050.000	21.264,8
2009	251.639	242.064	0,12751	32.085	30.864			1.050.000	23.014,8
2010	251.639	282.408	0,12524	31.516	35.369			1.050.000	24.764,8
2011	251.639	282.408	0,12302	30.956	34.741			1.050.000	26.514,8
2012	251.639	282.408	0,12083	30.406	34.124			1.050.000	28.264,8
2013	251.639	282.408	0,11869	29.866	33.518			1.050.000	30.014,8
2014	251.639	322.752	0,11658	29.336	37.626			1.050.000	31.764,8
2015	251.639	338.096	0,11451	28.815	38.715			1.050.000	33.514,8

The case study is continued on the next page.

[4] Exact energy generation of this specific wind turbine is provided until February 2007 by the Danish Energy Authority.

Table 4.3 Continuation of the case study on a 600 kW wind turbine in the North of Copenhagen

Year	feed-in tariff	feed-in tariff	feed-in tariff	annual Income	annual Expense	accumulated income	accumulated expense
	EUR 2006	EUR 2006	EUR 2006	EUR 2006	EUR 2006	EUR 2006	EUR 2006
1996	0,0999			43.449	51.983	43.449	51.983
1997	0,0980			98.785	60.846	142.234	112.829
1998	0,0961			109.279	59.676	251.513	172.505
1999	0,0949			97.452	65.318	348.965	237.823
2000	0,0906			94.924	62.357	443.890	300.180
2001	0,0884			88.965	66.816	532.855	366.996
2002	0,0871			100.531	65.823	633.385	432.820
2003	0,0852	0,0667		73.154	64.363	706.540	497.183
2004		0,0654		68.870	68.689	775.410	565.872
2005		0,0643		63.699	67.558	839.108	633.430
2006		0,0632	0,0450	48.153	66.359	887.261	699.789
2007			0,0446	44.032	65.717	931.293	765.506
2008			0,0435	45.661	64.088	976.954	829.593
2009			0,0427	44.850	62.950	1.021.804	892.543
2010			0,0420	44.054	66.885	1.065.857	959.427
2011			0,0412	43.271	65.697	1.109.129	1.025.124
2012			0,0405	42.503	64.531	1.151.632	1.089.655
2013			0,0398	41.748	63.385	1.193.380	1.153.040
2014			0,0391	41.007	66.963	1.234.387	1.220.002
2015			0,0389	40.880	67.531	1.275.267	1.287.533

August 2003 – full-load hours are used up

Turbine is ten years old

The example demonstrates that after using up the allowance of full-load hours according to the law, the benefit of the wind turbine increases very slowly due to the still high O&M costs. On the other hand, it can be seen that the high feed in tariffs of the first 12000 full-load hours are already covering the total installation costs of the turbine. This aspect becomes apparent in the following diagram, figure 4.7.

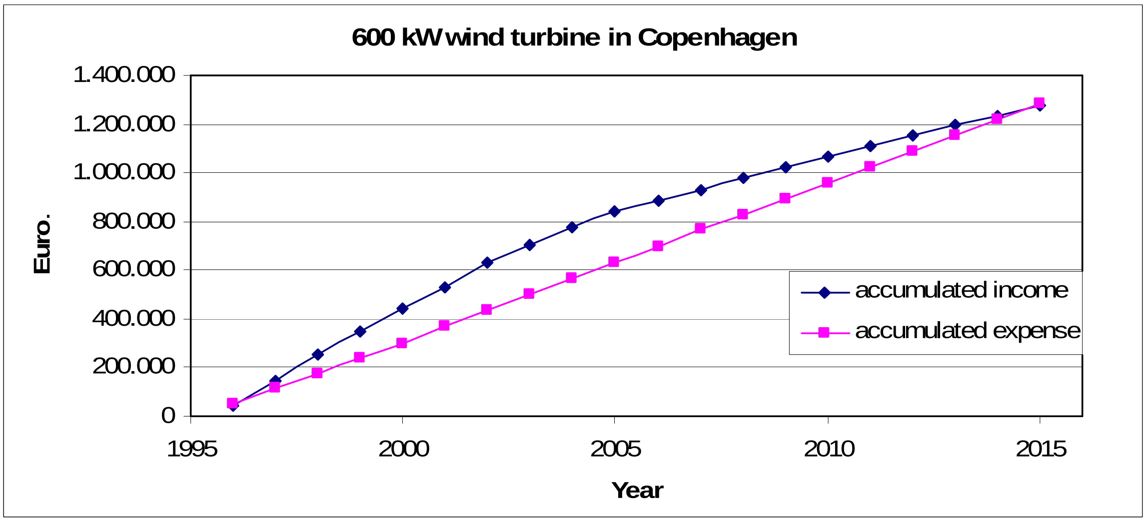

Figure 4.7 Economics of a 600kW wind turbine from 1996 in Copenhagen

An enormous increase of the income can be noticed compared to a slowly growing income after the 12000 full-load hours are used up. After the 20 years amortization period the accumulated expense will dramatically decrease, whereas the accumulated income will only decrease slightly.

4.1.4 Balancing system of wind power in Denmark

In general, wind power is not hundred percent predictable yet, and therefore the wind electricity generation varies from the forecasted output. In order to cover the demanded consumption of electricity every time, the deviation of the forecasted wind energy output to the real wind electricity generation has to be eliminated.

As figure 4.8 shows, the closer the time comes to the operating hour, the better the wind power forecast is made.

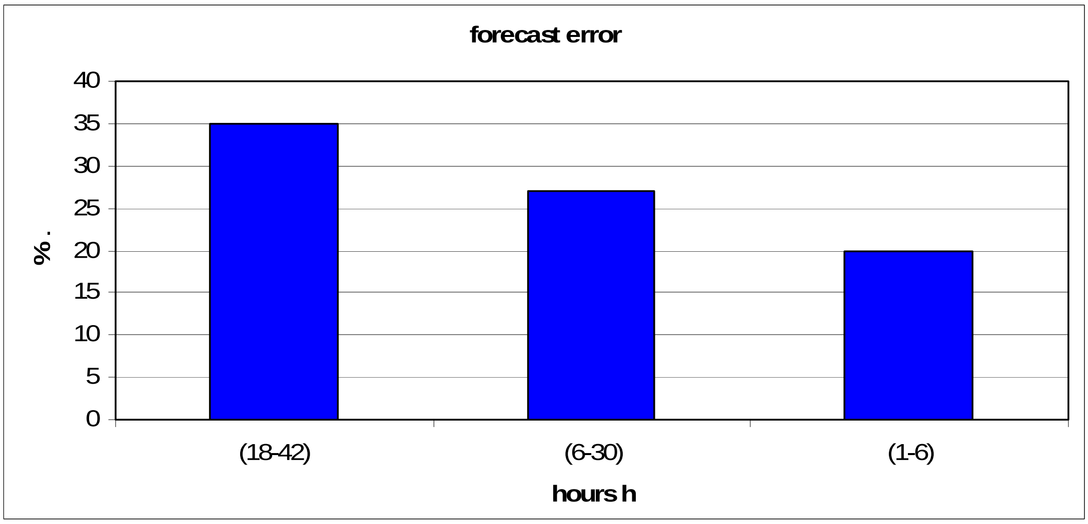

Figure 4.8 Errors in wind power forecast in East Denmark in 2005, depending on the time to the operating hour; Source: (Hay, C.; 2007)

Until now, Denmark, Sweden, Finland and Germany have joined the ELBAS market and it is expected the Norway will join in the near future. Due to the fact that ELBAS is opened until one hour to the operating hour, and conclusions of figure 4.8, ELBAS reduces the balancing costs of wind energy. The price on ELSPOT influences the ELBAS price, because at a high spot market price all producers want to sell their energy there, and fewer capacities are left on the balancing market which increases the ELBAS price.
Energienet.dk, the TSO of Denmark does not trade its balancing power on ELBAS because they consider it as a commercial activity, but Vindenergi Denmark, also one Balance Responsible Company, trades on ELBAS because less power is required. Nevertheless, the electricity production traded on ELBAS was only 100 MW in 2005, which is comparatively small; thus, most wind turbines are handled by Energinet.dk at NOIS.

In this way, the impact of wind power on the electricity price in Denmark is very big and the wind production even influences the spot market price when there is a lot of wind or hardly any wind. For this reason, other power plants have to be regulated, which causes the balancing costs.

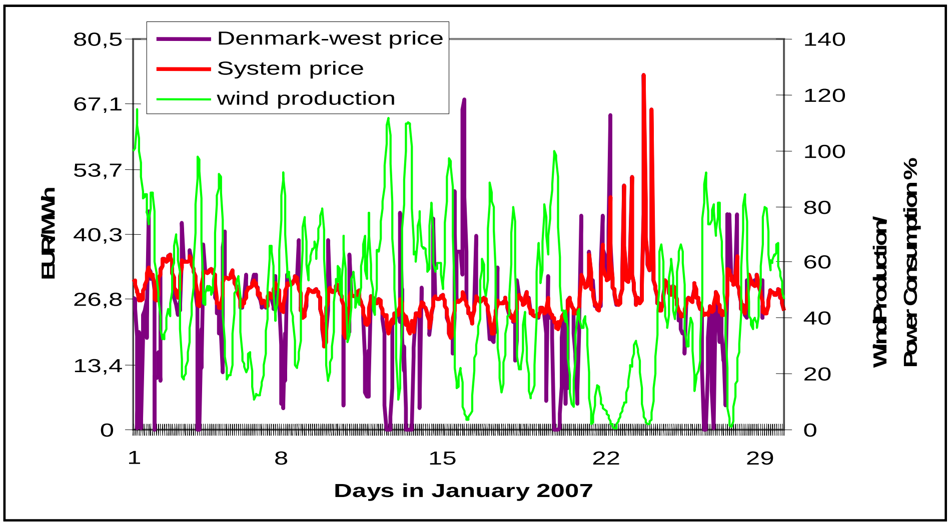

Figure 4.9 Influence of wind power production on the electricity price; Source: (Morthorst, P.E.;2007)

As can be seen in figure 4.9, days with wind generation higher than the energy consumption decreases the spot market price, whereas on days with hardly any wind production in Western Denmark, the spot market price exceeds peak prices of even three times of the normal price. This influence has to be avoided through a fast responding back-up power provided for the whole electricity market. Therefore, on the one hand the ELBAS market got introduced and on the other hand, the TSO has to physically balance the market.

The balancing costs for up-regulating and down-regulating amount to more or less the same price, although down-regulation might be a bit more expensive because another power producer looses a part of his income. Nevertheless, a power plant receives subsidies for being in standby mode.

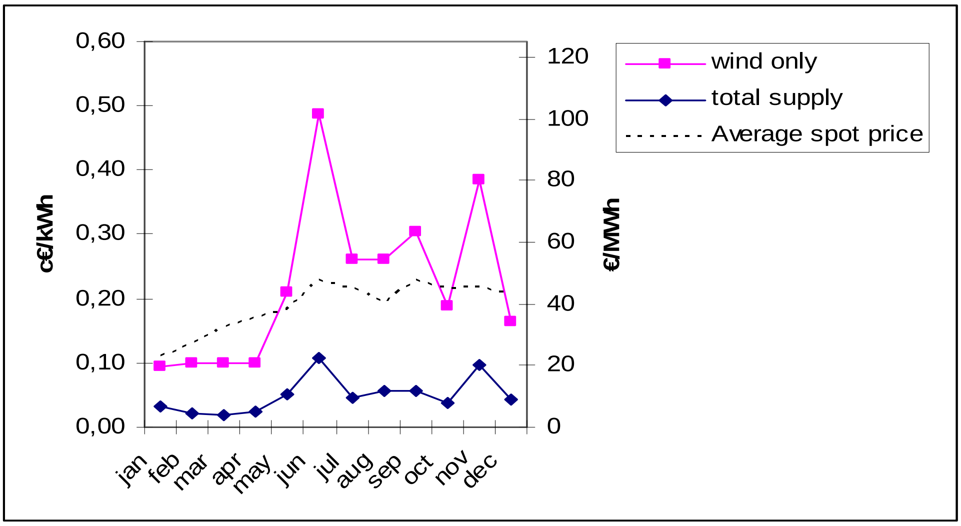

Figure 4.10 Balancing costs in 2005 expressed in Eurocents 2006; Source: (Morthorst, P.E.; 2007)

Figure 4.10 demonstrates the regulation costs in the year 2005 for wind power and for the total supply system measured on the left scale. In order to compare the regulation costs to the spot market price it is marked on the right scale. The prices for wind regulation are above the spot market price due to the uncertainty of quantity and time amount the back-up power is required.

With an increasing share of wind power up to 50% of consumption and more, the need for backup power will constantly increase. This growth of back-up capacity is either covered by newly installed gas-turbines, whereby these installation costs have to be taken into account, as well as socioeconomic matters because of higher environmental pollution, or further investments in transmission lines to the neighboring countries to import more hydro power have to be made. However, it is not yet decided how these further investments in more back-up power plants has to be divided in the need of providing balance power for wind turbines and balance power for the natural load fluctuations in the electricity system.

4.2 Grid integration of wind turbines in Denmark

Since 80 percent of onshore wind turbines in Denmark are spread all over the country, the grid integration is an important part in the socioeconomic costs of wind energy. How these costs can be split, and which advantages and disadvantages the different methods have, is discussed in the following subchapter. Furthermore, the real grid integration costs of wind energy are shown and divided in the different parts they contain. Finally, the model of refunding the occurring costs of the Distribution System Operators is described and discussed in detail.

4.2.1 Implementation of grid integration

The Danish electricity system consists of more than 166.750 km of high-voltage lines, whereas 6.000 km belong to the 400 kV and 132 kV / 150 kV systems. The 132 kV system is installed in eastern Denmark and in western Denmark a 150 kV system is installed. As a consequence of the Electricity Supply Act, two separated system operators were founded, which merged on August, 24th 2005 to one company called Energinet.dk. Energienet.dk is a state-owned company which owns and operates the 400 kV system and buys the 132 kV / 150 kV systems which it already operates since the founding of the company within the near future.
The distribution grid is operated by 115 separated companies which are responsible for enlargement and billing of the electricity distribution. These companies are mostly consumer or municipal owned and within their area they only have around 25.000 metering points. Their distribution tariffs have to be approved of by the Danish Energy Regulatory Authority (DERA) which also determines an income from tariffs for each company. This income is very little, whereas the grid company with the highest cost efficiency has the biggest income from tariffs.

In order to operate a distribution network, a license from the Ministry of Energy is needed. A Distribution System Operator can only obtain such a license if he releases all sales activities as it is required by the Electricity Supply Act. Furthermore, this Act includes a number of organizational obligations by an Operator. One of these obligations is that the Network Operator will not be allowed to have a license of supply activities. On the other hand, the Electricity Act does not specify a certain organizational form as obligatory.

As it is mentioned above, it is to distinguish between two different methods of implementing a new electricity generator to the grid. There are the “Deep Cost Approach” and the “Shallow Cost Approach”, whose advantages and disadvantages are discussed here.
The Deep Cost Approach charges the producer for all costs which appear by connecting the producer to the grid. This means that the producer has to pay for the connection to the grid as well as for all reinforcements which have to be done in the distribution and transmission grid. Moreover, a connection of a further producer can cause higher grid losses and therefore smaller grid reliability. To estimate these influences, the power producer gets charged too. Additionally, if there is a need to replace switchgears in the 10 kV system or higher up, also the embedded generator has to pay these costs, but investments in 10 kV/ 400V transformers are not covered by the power producer. In the Deep Cost Approach existing generators are not affected by new producers, which is considered as being one of the biggest advantages. Once a generator is connected to the grid, it is not affected by further

changes of the grid topology. Furthermore, grid efficiency is higher, thus every new producer will choose his location depending on the existing grid capacity in order to keep the investment costs as low as possible. The big disadvantage of the Deep Cost Approach is that the first generator in a new area has to bear all the costs by itself. This problem is relevant for wind turbines, since new wind turbines are mostly erected apart of an already existing grid area, which increases the investment costs of the wind turbine enormously. Therefore, the Deep Cost Approach is seen as a barrier of installing new wind turbines; thus, all grid investment costs are shared among comparatively small electricity production (Hiroux, C.; 2005).
On the other hand, the Shallow Costs Approach exits; it is applied in Denmark. Here, the power producer only pays the costs of connecting his generator to the grid. This means that only the investment costs for a switchgear and a cable to the grid is covered by the producer, while all other costs, for reinforcement in the grid levels above are covered by the system costs. The system costs can be shared among all end-consumers or all end-consumers and generators. In Demark the system charges are split between all consumers and the generators with a capacity above five MW. Wind energy producers do not pay any system costs. This approach is more favorable for new investors of wind turbines due to the lower investment cost and therefore lower production costs. A disadvantage is that it is not cost-reflective, thus the system costs do not only cover the investments in reinforcement of the grid.
Nevertheless, the Shallow Costs Approach offers more incentives to invest in distributed generators.

The Danish rules about who is responsible for connecting wind turbines to the grid are defined by the Electricity Supply Act §8 and §68. The connection costs are split into three participants, the wind turbine owner, the grid owner and the System Operator. How the total connection costs are divided up, is presented in the following table 4.4.

Table 4.4 Grid connection rules for wind turbines; Source: Transmission Lines Department

Wind turbine owner	For turbines with a capacity up to 1,5 MW, the owner shall bear all connection costs to the closest 10 kV grid node; it does not matter where the turbine will be physically connected (usually further away). For turbines with a capacity of 1,5 MW or higher, the system operator defines a connection point within the wind turbines area, to which the turbine owner shall bear all connection costs. This connection costs include the low voltage connection, a transformer, a meter and a service line to the grid.

Grid owner	Shall bear the costs of the system operator for dealing with the application for grid connection, maintenance for the grid company's meter and its calibration. Furthermore, he is responsible for the reading of the meter.
System operator	Shall bear all the costs for enlargement and reinforcement of the grid, the grid losses and the phase compensation for reactive power which is not consumed by the turbine.

Table 4.4 shows that the Shallow Costs Approach that is implemented in Denmark.

4.2.2 Grid connection costs of wind turbines

This subchapter discusses the grid connection costs of the local Distribution System Operators. These costs are caused by extensions or reinforcements in their distribution grids. A reinforcement of the 60 kV/10 kV transformer station is also taken into account. Furthermore, only the costs are regarded, which concern the Distribution System Operators according to table 4.4, whereas all the grid connection costs concerning the wind turbine owner are included in the investment costs of a wind turbine.

The distribution grid consists mainly of two voltage levels, the 10 kV level where all the wind turbines are connected and the 60 kV level where the energy is distributed within the areas of the DSO' s. Whereas the topology of the 10 kV level had to be changed and extended in order to operate a reliable system, the 60 kV level was strong enough to handle the additional electricity produced by wind power. Therefore, the topology of the 60 kV grid did not change due to connecting the wind turbines to the grid and no costs occurred.

Since wind turbines got connected directly to the 10 kV girds, these grids underwent changes in their topology; these changes vary wildly depending on the area. Thus, most wind turbines are installed in the North-Western part of Jutland the biggest changes happened there while hardly any changes are observed on the countryside of Zealand. Unfortunately, it is impossible to provide a total overview of the impact of wind turbine connections to the distribution grid topologies, as Denmark is divided into 115 distribution areas. Therefore, the situation of one area in the North-West of Jutland is chosen as a representative for distribution grids with a high penetration of wind turbines.

The selected Distribution System Operator runs 161 wind turbines in his area with a total capacity of 80,127 MW, which amounted to 2,76 percent of the total wind capacity in the year 2005. In this area 50.200 metering points are installed and 537 GWh were distributed in 2005[5].

Figure 2.14 illustrates the grid extensions due to new grid-connected wind turbines in this specific area. In order to handle this new wind power, the distribution grid got reinforced and extended in a total of more than 75 kilometer cables.

This enlargement of the grid caused costs, whereof the major parts are the cable itself, the digging of the trench and the laying and installing of the cable. The specific costs are presented in figure 4.11 below.

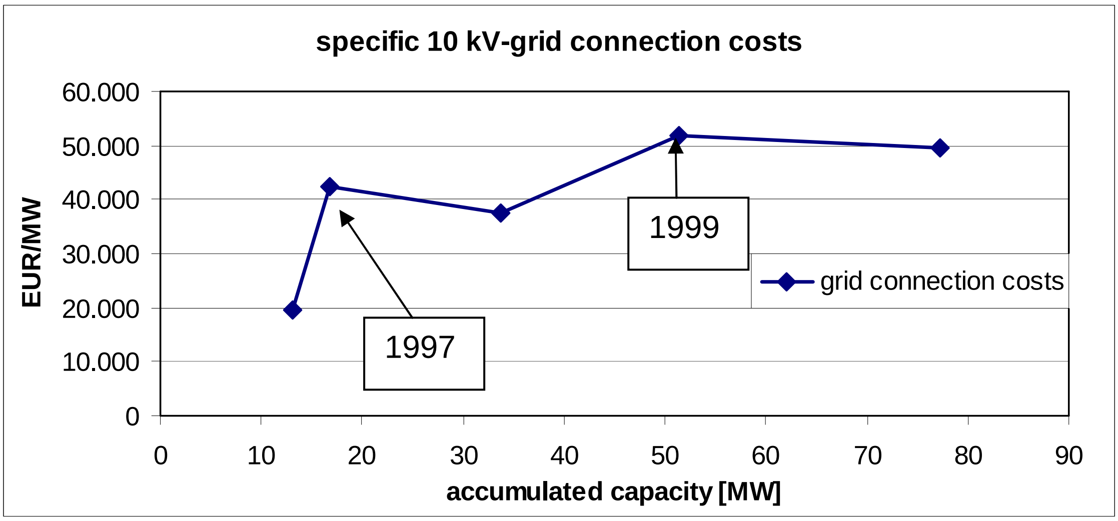

Figure 4.11 specific costs of the 10kV grid extension in the certain area; Prices in Euro 2006

Figure 4.11 allows two main statements. Firstly, the shape of a staircase results from the fact that the 10 kV grid in that area was always designed stronger as it was supposed to be. High investments in the grid had to be done in order to connect the new wind turbines in 1997. These strong extensions in the grid allowed connecting wind turbines in the following year at lower investment costs in the grid, whereas between 1999 and 2000 the same procedure can be observed. Secondly, a constant growth of specific grid connection costs is determined. On the one hand, the more wind turbines are installed, the further enlarged the grid becomes but on the other hand, when the closest wind power locations are used up with small capacity generators, new powerful turbines have to be erected further out in the countryside, increasing the connection costs again. This historical deployment of the grid infrastructure, reduces the advantage of a strong designed grid a bit, because the already existing grid has to be reinforced to handle the new power which is connected further out, and therefore the total specific connection costs increase.

[5] Expert interview with the responsible local Distribution System Operator

In order to demonstrate the specific costs of grid integration of wind generators, figure 4.12 shows the trend of the specific costs scaled on a connection distance of one kilometer for all wind turbines.

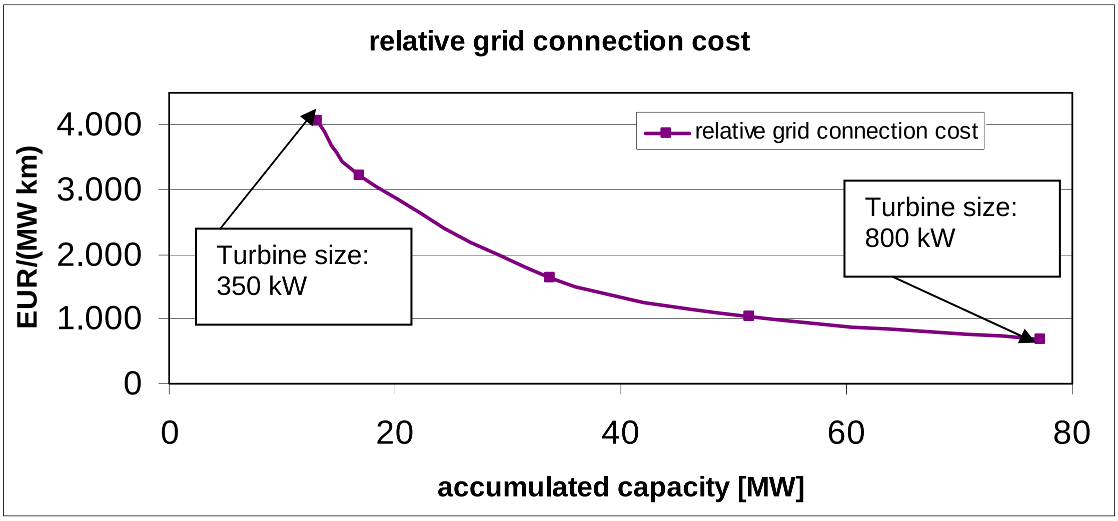

Figure 4.12 Gird connection costs for all wind turbines on a fictive distance of 1 km and increasing turbine sizes; Prices in Euro 2006

A dramatic decrease of grid connection costs is observed by increasing wind turbine power sizes. It is to mention that these costs do not reflect the real costs and are only a calculation to compare specific grid connection costs for different wind turbine sizes at a fictive grid connection distance of one kilometer. These costs only reflect investments if old wind generators are up-scaled, whereby the necessary reinforcement of the grid counts one kilometer.

Besides, the enlargement of the distribution grid itself, some 10kV/60kV transformer stations had to be reinforced or replaced too, in order to handle the newly installed power. Thus, such transformer stations typically have a nominal power of 20MW and in total 80,127 MW of wind power were installed in that area; these investments of the local Distribution System Operator cause only a very little part. Reinforcements of a transformer station means for instance to add a cooling system, but only very few cases appeared in that area; it has not been necessary to substitute or reinforce the transformer stations because they were mostly designed more strongly than required. All over Denmark only 17 new transformer stations were set up in the period between 1996 and 2005.

The impact of wind power on the transmission grid has been smaller. Since Denmark is considered as a transit country for energy from the Nordic countries to Germany, the national transmission grid is very strong. A reinforcement of the grid took place between Aalborg and Aarhus, but this cannot be ascribed to wind power. Nowadays, the Danish Energy Authority verifies an extension of the 150 kV line from Viborg to the North-West shore where the wind generator density is very high. However, no decision is made so far and if it will be approved that the enlargement is economically feasible, it will take at least two more years until the new line is realized. The costs for this possible enlargement of the 150 kV grid would be covered by the grid tariff of the Transmission System Operator, which would not cause a serious changing of the electricity price for the end-consumers.

Finally, it has to be taken into consideration that the presented changes in the distribution grid are not the total changes, they are only the part of which the Distribution System Operator is responsible. The 10 kV cables within the area of the wind-park to the virtual connection node and all the single 10 kV transformer stations for every, wind turbine are not regarded here, because they are paid by the wind turbines owner and are therefore included in the investment costs of a turbine. As an example, a certain wind park with five 660 kW turbines requires five 800 kVA transformer stations and 850 meters of 10 kV cables, which causes total costs of 240.000 Euro in 2006. These are about 70 EUR/MW, which amounts approximately six percent of the total investment costs[6].

A final example gives information about the composition of the grid connection costs for the Distribution System Operator. The above mentioned wind park with a total capacity of 3,3 MW is connected by a 3x150 mm² AL cable to the 10 kV grid. The technically most feasible connection point is 4,51 km away and the cable is laid only 90,2 meters into the city whereas the rest is at the countryside where digging a trench is much easier and therefore cheaper. The calculation is shown in table 4.5.

Table 4.5 Connection costs of a 3,3 MW wind park 4510 meters apart from the 10 kV grid, Euro 2006

3,3 MW wind park in 1998		
	costs EUR/m	length m
trench city	89,51	90,2
trench country	25,57	4.419,8
cable	22,92	4.510,0
cable roll-out	2,72	4.510,0

Installed capacity	3,3 MW	
cable typ	3x150 AL	
	EUR 2006	%
trench cost	121.108,4	51,2
cable cost	103.362,9	43,7
cable roll-out cost	12.277,2	5,2
total costs	**236.748,5**	**100,0**

4.2.3 Socialization of grid connection costs evolved by wind turbines

Since wind turbines which are erected close to the shore and higher full-load hours than in the countryside are scheduled, most of the Danish wind mills are set up in the North-West part of Jutland. Hence, the Distribution System Operators in that part have much higher expenses connecting the wind turbines to the 10 kV grid than System Operators in other parts of the country. This would lead to wildly varying distribution grid tariffs, and households in the North-West part would have to pay the

[6] Expert interview with the responsible local Distribution System Operator

whole costs for a wind turbine. In order to introduce fair distribution tariffs for all households, the Act on Electricity Supply number 286 provides rules how to spread the costs. The first part of paragraph §8 in this Act regulates, that every electricity consumer shall bear a relative proportion of the expenses which all the Distribution System Operators invest in their grids. This proportion is part of the Public Service Obligations PSO. Furthermore, the fifth part of paragraph §8 points out that the rest of the investments in the grid are covered by the individual distribution grids.

In order to socialize the grid connection costs of wind turbines as it is determined in the Act on Electricity Supply, the Transmission System Operator, Energinet.dk, developed a model which estimates the investment in the distribution grid and refunds this estimation to the local Distribution System Operators. These estimations disregard the real investments and are paid only in accordance to the model; it does not matter what the DSO had to do in reality.

The model specifies a grid connection point in the area of the wind park, if the power of the wind park exceeds 1,5 MW or more. The distance from this grid connection point to the closest existing 10kV node is taken into account in the model. Here, it does not matter where the wind park is physically connected to. Mainly the bigger wind parks are directly connected to 10kV/60kV transformer stations. In this way, it might happen that the Distribution System Operator still bears a high percentage of the grid extension and reinforcement costs or the total investment gets refunded. In certain cases, when the existing grid is strong enough to add the new wind park, the DSO does not have to make any action but gets the refunds as it would have to reinforce the existing 10 kV grid (Helstrup, N. E.; 2007).

The calculations of the refunding costs are regulated in the bye-law NOTAT 02-001e, whereof the main issues are explained in table 4.6 below.

Table 4.6 Refunding model for grid connection expenses of the individual Distribution System Operators in action since January 1st, 2007 following the NOTAT 02-001d Prices in Euro 2006; Source: Danish Transmission System Operator – Energinet.dk (Helstrup, N.E.; 2007)

$refund = baseprice + (cableprice + trenchprice) * length * 1,1$		
base price	Wind parks smaller than 2 MW	4.032 EUR
	Wind parks between 2 MW and 5 MW	48.388 EUR
	Wind parks between 5 MW and 10 MW	96.776 EUR
	Wind parks between 10 MW and 15 MW	145.163 EUR
	Wind parks between 15 MW and 20 MW	193.550 EUR
	Wind parks between 20 MW and 25 MW	241.938 EUR
cable price	$cableprice = (5,107 * P[MW] + 6,72)$	EUR/meter
trench price	Digging price in the city	53,67 EUR/meter
	Digging price on the countryside	16,13 EUR/meter

Furthermore, Distribution System Operators receive a refund for investments in their 10 kV/60 kV transformer stations. If the grid connection of new wind parks requires reinforcement or substituting of these transformer stations, the model estimates the necessary expenses. As the refunding of the grid extension costs, the amount of money which is refunded to the Distribution System Operators does not reflect the real investments. In most cases, the 10 kV/60 kV transformer stations are strong enough and no changes have to be made but nevertheless a refund is paid according to the bye-law NOTAT 02-001e. The model for refunding the investments in these transformer stations is explained in table 4.7 below.

Table 4.7 Refunding model for transformer station expenses of the individual Distribution System Operators in action since January 1st, 2007 following the NOTAT 02-001d Prices in Euro 2006; Source: Danish Transmission System Operator – Energinet.dk (Helstrup, N.E.; 2007)

Add cooling system	reinforce / replace station
$refund = 13.414 * (S_{new} - S_{actual})$	$refund = 26.882 + 24.865 * (S_{new} - S_{actual})$
$S_{new} = \sqrt{P^2_{wind,total} + Q^2_{wind,total}}$ $S_{actual} = S_N$ of actual wind capacity	
Nominal sizes of transformers: 8 MVA, 13 MVA, 20 MVA 31,5 MVA	Nominal size of transformers: 6,3 MVA 10 MVA, 16 MVA, 25 MVA

The presented formulas in table 4.7 calculate the refund, whereas the calculated power always has to be the next bigger nominal power than that which is required due to the installed wind capacity. If only a small capacity is added to the grid, and the transformer can handle this power only by adding a cooling system, the left column of table 4.7 is used. On the other hand, for reinforcing a transformer station, setting up an additional transformer in the same station or replacing the older transformer by a new one the right column of table 4.7 is used.

Table 4.6 and table 4.7 point out how the expenses of the Distribution System Operators for grid-connecting wind turbines are refunded by the Transmission System Operator. This bye-law NOTAT 02-001e is in action since January 1st, 2007 and followed the old NOTAT 02-001d where the only difference is the increased refund for digging the trench (Koch, J.; 2007).

The subscribed method allows spreading the local investment all over Denmark and no disadvantages appear for consumers in areas with a high wind park density. Figure 4.13 illustrates the annual refunds of Transmission System Operator per annually installed capacity.

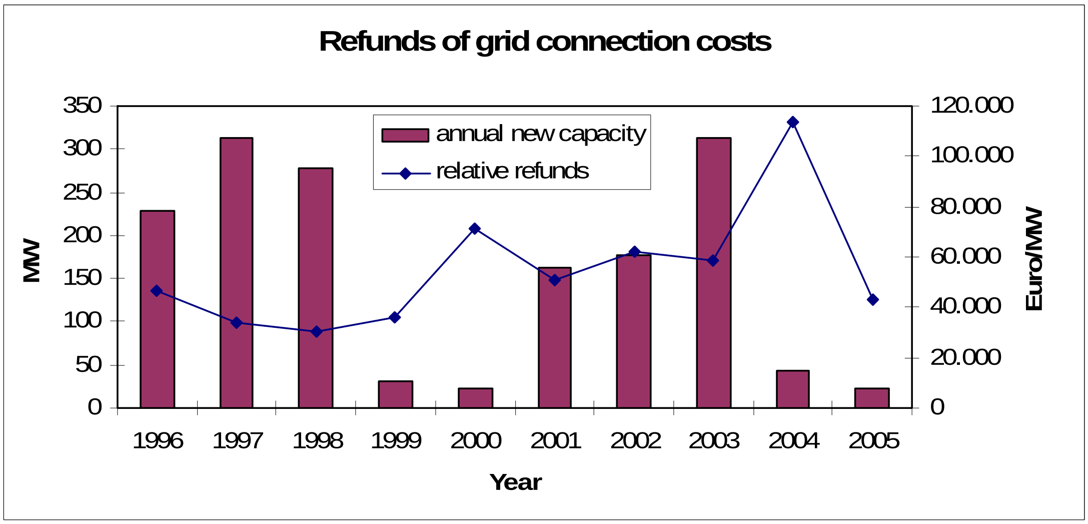

Figure 4.13 Refunds per capacity in Euro2006/MW for changing grid topology due to wind power

These average refunds in figure 4.13 do not reflect the real refunds because, as is mentioned above, the refunds cover in some cases the total expenses or even more and in some cases only a part of it. On the other hand, figure 4.13 demonstrates that a lot of reinforcement and enlargement of the distribution grids was necessary in 2000 and 2004. In the years before, new wind generators could be connected to a closer grid node, as happened in reality. This results in smaller relatively refunds (Helstrup, N. E.; 2007).

All the expenses the Transmission System Operator, Energinet.dk, has to make in order to pay the refunds to the local Distribution System Operators, are covered by the Public Service Obligations (PSO). Major parts of the PSO are the subsidies of renewable energy producers and the refunds in the distribution grids. Generally, the Public Service Obligations decreased since they got introduced in the electricity market because the gap between the electricity spot-market price and the fixed feed-in tariffs got smaller due to an increasing spot-market price. The PSO is claimed by Energinet.dk, who as well calculates the amount of the PSO every three months. The expected amount of subsidies and costs of refunding is estimated and divided by the total predicted electricity consumption. Therefore, the PSO can vary wildly between each calculated period between 0,01 c€/kWh and 0,15 c€/kWh. In this way, every electricity consumer pays a part of the investments in the distribution grids as well as for using renewable electricity power.

In most cases, the real grid-connection expenses are higher than the refunds from Energinet.dk, since the shortest distance to the next 10 kV node is often not the technically best solution and therefore a longer connection line has to be built. The difference between the real expenses and the refunds are covered by the local grid-tariffs because Distribution System Operators are non-profit companies, except the most efficient, which are allowed to make a small profit.

These local grid tariffs contain mainly two parameters. Firstly, the rest of the expenses in the grid topology have to be covered by them and secondly, the O&M costs of the Distribution System Operator are included in these tariffs. In order to calculate the influence of the grid expenses on the grid tariffs, an amortization period of 30 years is taken into account. Moreover, the grid tariffs are adjusted every three months in order to balance the turnover of the Distribution System Operator.
Nevertheless, the distribution grid tariffs vary in between the individual Distribution System Operators, but these differences are caused by other influences, as for instance grid connections of new households or changes in the grid due to a not foresighted design of the original grid. The range of grid tariffs in the first quarter of the year 2007 varied between 0,27 c€/kWh and 1,22 c€/kWh.

The final example presents the calculations of refunding the grid-connection costs of the wind park presented in table 4.5 which was installed in 1998, consisting of five wind-mills and with a total capacity of 3,3 MW.

Table 4.8 Refunds of the 3,3 MW wind park table 4.5, 4510 meters apart from the 10 kV grid Prices in Euro 2006

3,3 MW wind park in 1998				Installed capacity	3,3	MW
	costs	length		cable typ	3x150 AL	
	EUR/m	m			EUR 2006	%
trench city	64,05	74,6		trench refunds	74.990,8	41,7
trench country	19,22	3.654,0		cable refunds	104.724,4	58,3
cable	28,09	3.728,6		total refunds	179.715,3	100,0
				total expenses	236.748,5	100,0
costs to cover by the DSO					**57.033,3**	**24,1**

In table 4.8 it is shown that the closest 10 kV node is only 3.728,6 meters apart from the grid connection point and therefore the Distribution System Operator has to cover 24,1 percent of the expenses by himself according to the local grid tariffs.

5. Economics of small-scale CHP plants

The second major part of distributed generation within this thesis, are small-scale Combined Heat and Power plants (CHP). In Denmark, nearly 300 CHP plants have been installed until now, whereof almost 200 plants have a capacity of less then 3 MW, about 90 plants come up to 25 MW and the rest has a capacity above 25 MW. The fuel efficiency of a CHP plant is around 30 percent higher than producing heat and electricity in extra plants, which was the target of the energy plans in the early nineties. Therefore, several subsidies are eligible for running and operating CHP plants, which had a big influence on the electricity market.
In the first subchapter, the levelized electricity generation costs of different CHP plants are calculated and their major components are explained. In order to calculate only the electricity costs of a CHP plant, some rules have to be taken into account. This is also discussed here.
Secondly, an overview of the Danish heat market is given, which allows an understanding of the economical feasibility of CHP plants in the right way. Furthermore, an overview of the economical aspects of the District heating system is presented. Finally, the third subchapter highlights the different legislations for connecting the small-scale CHP plants to the grid. Moreover, examples and diagrams show the costs caused by grid connecting them and how the grid tariffs for the end consumer reflect these costs, respectively how these costs are socialized.

5.1 Generation costs of small-scale CHP plants

Within this subchapter, the first part explains the different parameters which influence the levelized electricity generation costs. Therefore, the generation costs are calculated depending on the different kind of fuels and moreover, some sensitivity analyses are discussed.
Furthermore, the Danish heat market structure is explained and the deriving advantages for small-scale CHP plants are illustrated.
Finally, the different kind of revenues are demonstrated in the last subchapter. Moreover, a case study on a small-scale, waste incineration CHP plant explains the economics.

5.1.1 Calculation of levelized generation costs

Since there are two products of CHP plants – electricity and heat – it is very difficult to allocate the exact production costs for both products. In order to calculate levelized generation costs of electricity, the typical approach for large-scale CHP plants is to consider heat only as a marginal product. Thus, the heat production is allocated only to the marginal extra costs compared to an electricity-only plant. The approach for

small-scale CHP plants is the other way round, because most small-scale CHP plants were heat only plants in former times and got converted to CHP plants due to governmental decisions. Therefore, the amount of fuel used for heat production is set equal to the amount which a heat-only plant would use and so electricity is considered as the marginal output. In this way, small-scale CHP plants can sell their electricity at a competitive price to the electricity supply system.
Moreover, in a CHP plant only the fuel used for heat production is taxable, in order to keep the competitiveness on the liberalized electricity market. Electricity is taxed only for the final consumer. To calculate the amount of taxable fuel of CHP plants, operators may choose one of two ways. Either the fuel for heat is the heat production divided by 1,25, or the total fuel minus the electricity production divided by 0,65 (Pedersen, S.L.; 2007).

In consideration of the advantages of fuel compared to a power-only plant, the levelized electricity generation costs are calculated as the following (Haas, R.; 2005)

$$c_{el} = \frac{\alpha * I - H}{t} + c_{O\&M} + \frac{c_{fuel}}{\eta}$$

$$\alpha = \frac{(r+i)*(1+r+i)^n}{(1+r+i)^n - 1}$$

c_{el}	levelized generation costs [EUR/kWh]
α	Annuity factor
I	Investment cost [EUR/kW]
H	Heat income [EUR/kW$_e$]
t	Full-load hours [kWh/kW]
$c_{O\&M}$	annual O&M costs
r	risk rate [%]
i	discount rate [%]
n	amortization period [a]
c_{fuel}	fuel price [EUR/kwh]
η	effectiveness [%]

As these calculation formulas show,
the O&M costs, the fuel price and the heat income influence the electricity generation costs. These influences vary a lot depending on the fuel the CHP plant uses.

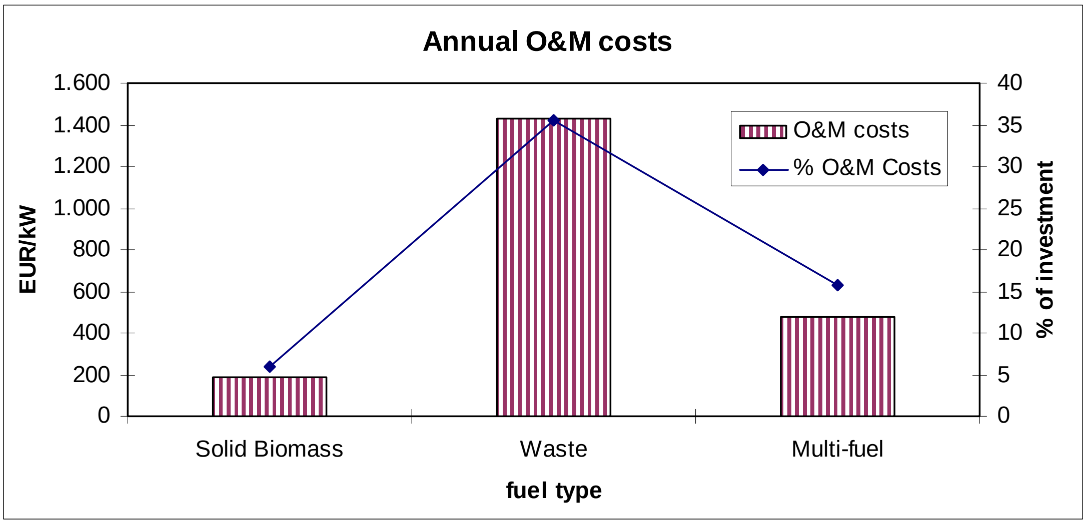

Figure 5.1 Annual O&M costs of different small-scale CHP plants, depending on the fuel in EUR/kW on the left scale and in percent of the total investment costs on the right scale

Figure 5.1 clearly demonstrates the big differences of O&M costs in different kinds of CHP plants. The solid Biomass fuel consist to 75 percent of straw and 25 percent of woodchips, and the multi-fuel consists to 17 percent of woodchips, 56 percent of waste incineration and the rest is natural gas. The annual O&M costs of a waste incineration plant amount up to more than 35 percent, which is mainly caused by the preparations the waste has to undergo before it can be combusted. This is also the reason why the O&M costs of the multi-fuel plant, with 56 percent of waste, amount to more than a treble of the straw plant. As it is shown further on, waste incineration plants are eligible for different kind of subsidies to be competitive on the market.

One of these subsidies is a grant paid to the power plant owners per each ton of waste they burn in their plant. This grant does neither depend on the waste from households, nor from the industry sector and therefore it always amounts to 44,35 Euro per ton of waste.

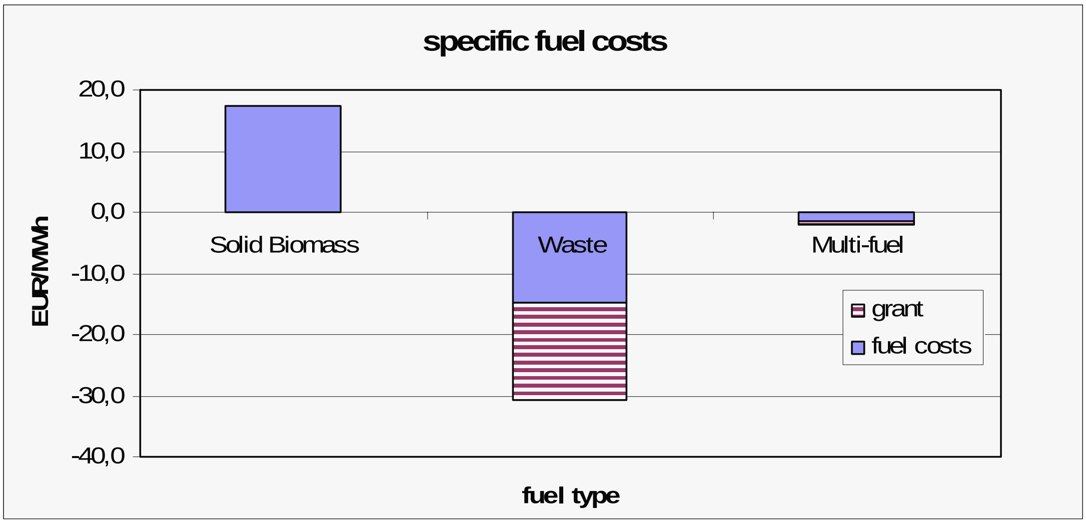

Figure 5.2 Fuel costs of different kinds of fuel in Euro per MWh in 2006

Figure 5.2 presents the fuel prices per MWh energy of the fuel from the year 2006. Solid Biomass and multi-fuel contain the same parts as mentioned before. Whereas the price for straw in Denmark is stable since a few years at 4,83 EUR/GJ, the price for woodchips increased by 30 percent to the same price level like straw. Furthermore, waste incineration plants receive almost halt of their fuel price from grants from the TSO and the price for waste of households and the industry sector vary in up to 13 Euro per ton of waste. This income of the fuel they use for power and heat production, compensates the high O&M costs of their plants in order to produce energy at a competitive level. Thus, the multi-fuel contains nearly half of waste, the amount of fuel indicates almost zero Euro/kWh. Unfortunately, no prices for natural gas the plant owners pay were available, but it varied between 4 c€/kWh and 5 c€/kWh in 2006, depending on the yearly consumption.

Finally, the third parameter which influences the electricity generation costs is the income of the sell of the heat to District heating companies. The heat price and its impacts are discussed in detail in the next subchapter.

The levelized electricity generation costs are calculated with respect to data which was given by responsible persons of the different CHP plants[7]. Therefore, the diagram in figure 5.3 only demonstrated the generation costs of these certain CHP plants, although it might be seen as approximate generation costs. A discount rate of 7 percent is taken into account for these calculations. which is usually used for CHP calculations.

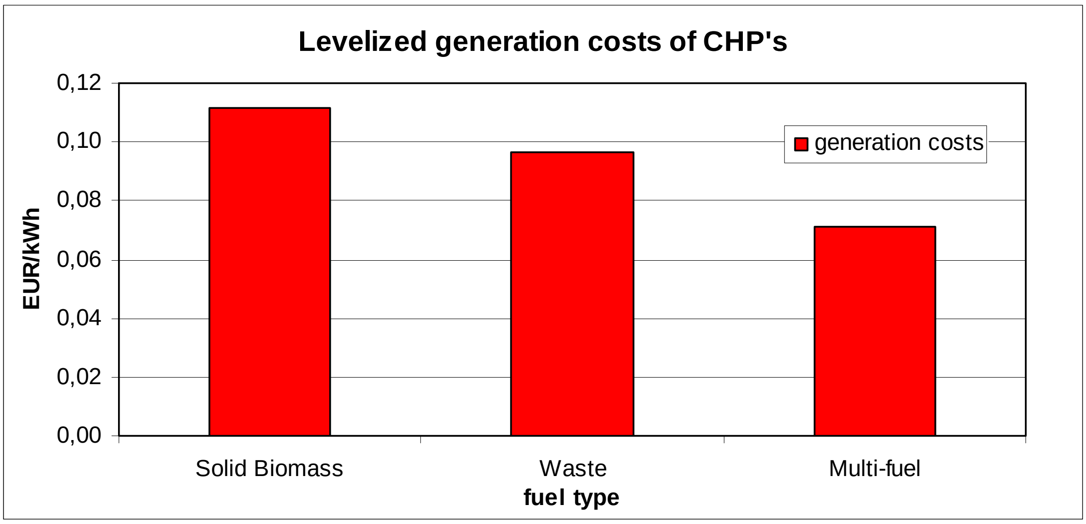

Figure 5.3 Levelized generation costs of different CHP plants sorted by kind of fuel (Prices in EUR 2006); Data provided by Dong Energy and EnergiGruppen Jylland

These levelized generation costs for the different small-scale CHP plants, with capacities between 5 and 30 MW, are all very high compared to the Nordic spot market price. This occurs due to two reasons. Firstly, small-scale CHP plants are back-pressure CHP' s, and run on the heat demand of the connected District heating system. Therefore, the average electricity full-load hours in areas where this power plant is not the only heat provider, are around 4000 hours. That causes higher production prices. Secondly, in the end of the nineties no investors were found for CHP plants if the amortization period was higher than 10 years, which meant a very short period (Koch, J.; 2007). This influence of a too short amortization period is presented in figure 5.4 below. Since CHP plants have a second income due to selling heat, the high electricity costs are covered by them. Moreover, small-scale CHP plants are eligible for different kinds of subsidies like the three-time tariff that is explained later on.

[7] Responsible persons at EnergiGruppen Jylland and Dong Energy

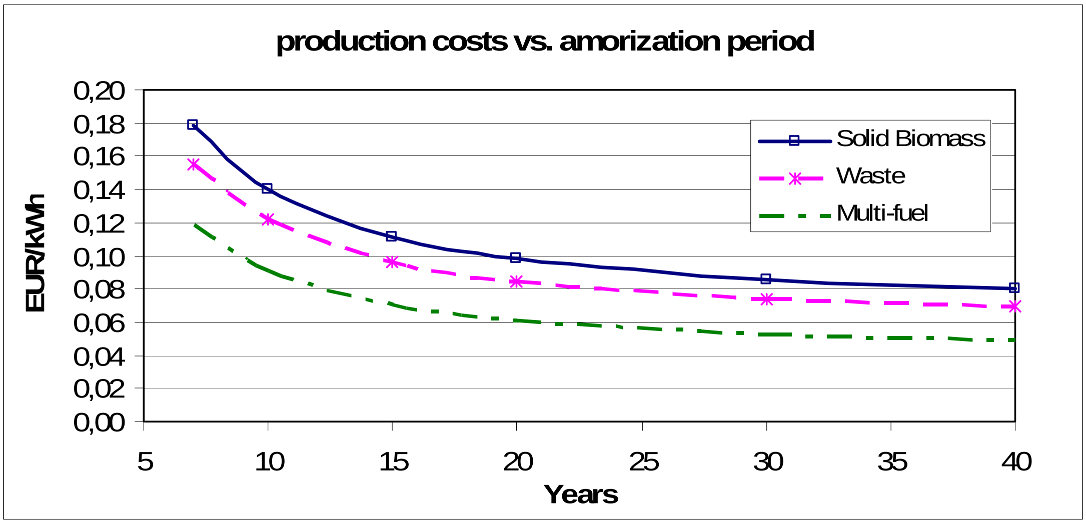

Figure 5.4 Levelized production costs over different amortization periods (Prices in Euro 2006)

5.1.2 Heat market characteristics in Denmark

Within the EU, the Danish District Heating system is the best developed. The whole system encompasses 50.000 km of pipelines and almost 60 percent of the heat is provided by CHP plants. Only in the last ten years about 400.000 new consumers got connected to the distribution grid, which in total amounts to more than 80 percent of all households.

The penetration of District heating is a result of several laws and Acts decided by the government. In Denmark, it is an obligation for households to connect to the District Heating system and stay connected. Local authorities have the power to require that all or part of the local commune is connected either to a natural gas supply or the District Heating system. This is written down in the Executive Order no. 196 of June 1991, which is part of the Act on Heat supply of 2000. Furthermore, the order does not distinguish between existing households and new ones. As a result of this order, almost 90 percent of the local authorities apply the obligation to connect for either new buildings or new and existing buildings. The authorities have to fulfill several approvals before they can apply the obligation.
The advantage of the application of this order for the consumers, is simply that the more households are connected the cheaper heat becomes for each household. On the other hand, it also has an environmental advantage because the fuel efficiency of a bigger CHP is much higher than a small burner in every household. Where and how the connection is applied, depends on the political interests of the authorities, too. In politically liberal communes, several incentives are given to the heat consumer to buy their heat from District Heating and social democratic areas force the consumers to connect, because the more are connected the cheaper it is for the people (Pedersen, S.L; 2007).

The heat price for consumers of District Heating plants vary widely from area to area and therefore the income for a CHP plant per GJ of heat also depends on this factor. If the CHP plant is the only heat producing plant in the district heating system, it dictates the price for it. The electricity price is regulated through the spot market price plus all the subsidies it is eligible for. The rest of the yearly costs have to be covered through selling the heat to the heating system. As it is presented in figure 5.5, the electricity generation costs depend on the fuel the CHP plant uses. While in erecting a small-scale CHP plant several approvals have to be made (and if, for instance, Biomass was the cheapest solution for that area) it cannot be changed again. In the mid-nineties, Biomass was around 30 percent cheaper than it is nowadays. Moreover, there are no taxes on CO2 and NO_x produced by Biomass compared to natural gas. Due to these reasons, local areas with only Biomass CHP plant have higher heat costs than areas with different kinds of CHP plants.

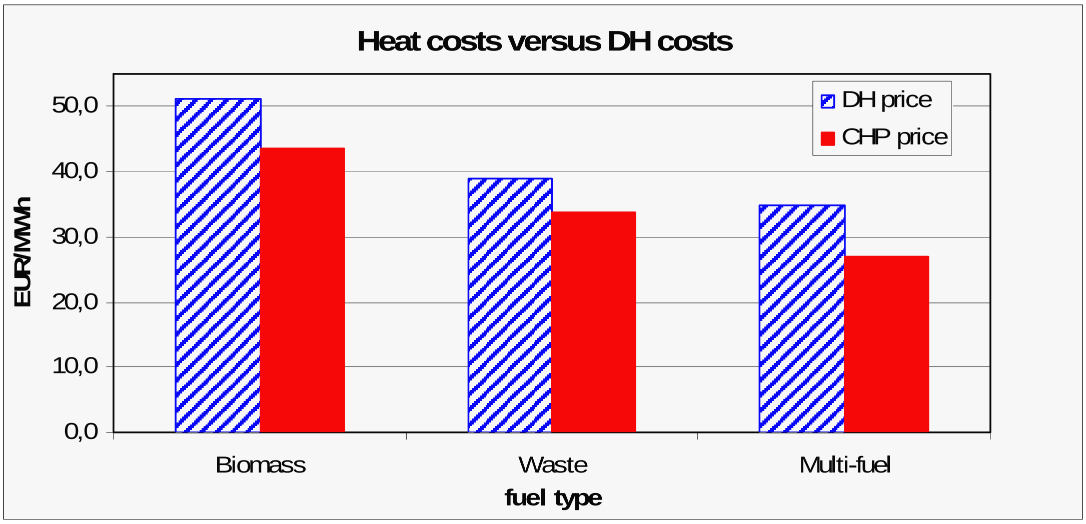

Figure 5.5 Heat credits for CHP plants and heat prices for consumers in the areas of DH

Figure 5.5 demonstrates the different heat prices for consumers exclusive VAT, as well as the incomes for CHP plants depending on the fuel used in the CHP plant. Obviously, the CHP plant with the highest electricity production costs has the highest heat costs as well, due to the non-profit activities of the energy producer. The difference between electricity production costs and electricity income is covered by selling the heat (Koch, J.; 2007).

Nevertheless, the District Heating system is mostly considered as the cheapest opportunity for heating in Danish households. If an average Danish household with 130 square-meters is heated up by a private oil burner, it causes about 2700 Euros per year, compared to a private natural gas burner which causes around 2150 Euros annually. As is mentioned before, only in a few areas in Denmark is it allowed installing private oil burners; mostly these are exceptions for single houses far out in the countryside. Compared to the heating costs above, district heating causes much less costs: only eight percent of district heating households pay more than they would pay with a natural gas burner and only two percent pay more compared to a private oil burner (Odgaard, O.; et at.; 2007). This relation is shown in figure 5.6 below.

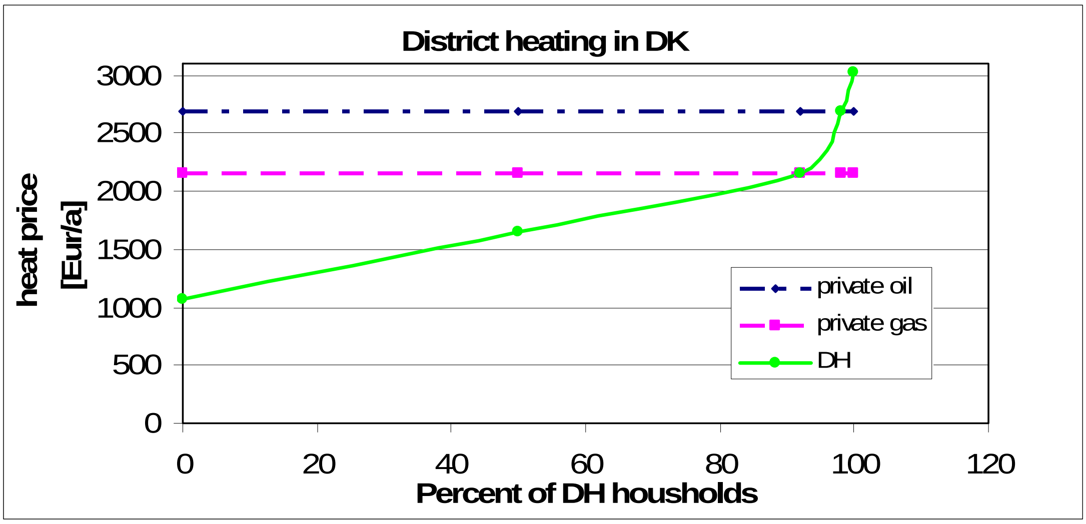

Figure 5.6 Percentage of District Heating consumers paying more than at private heat generation

The optimal power size of small-scale CHP plants is considered as 0,06 MW of thermal power per Terajoule heat required in the District Heating system. Therefore all small-scale CHP plants are planned to cover primarily the heat demand in their area and out of this planning an electricity output is given. The heat consumption of one private house amounts to 65 Gigajoule per year, which means that a thermal power of 1 MW can provide heat for about 250 households; this is the lower limitation of an average small-scale district heating network.

5.1.3 Income of local small-scale CHP plants

Although the electricity production of decentralized CHP plants provides one quarter of Denmark's total consumption, they still need to receive subsidies in order to be competitive at the Nordic power market. These kinds of subsidies depend mostly on the kind of fuel, the age and the size of the plant. Furthermore, the different subsidy schemes have changed over time to promote new plants. In the mid-nineties, small-scale CHP plants were eligible for several different grants as well as for investment subsidies. They amounted to 30 percent of the total investment as building, turbine, burner and grid connection. Nowadays, no investment subsidies are paid anymore, and only subsidies for electricity production are eligible. Some tax reductions, for instance no Biomass tax on fuel to produce heat, are considered as heat subsidies, but no grants are paid per GJ of heat production.
In the following table 5.1 the present subsidies for electricity production sorted by fuel are explained and the changes in the subsidy scheme are mentioned.

Table 5.1 Subsidy rules according to §57-§58 of the Danish Electricity Supply Act

Renewable energy source, existing CHP plants	The TSO sells the electricity on the spot market. The plant owner receives a fixed feed in tariff of 8,06 c€/kWh, which contains the spot market price and a subsidy. This tariff is paid 20 years from the grid connection, but at least 15 years as from January 1st, 2004. Afterwards, the CHP plants run on the spot market conditions.
Renewable energy source, new CHP plants	Biogas plants and plants operating a Sterling motor, receive a feed-in tariff of 8,06 c€/kWh for 10 years and 5,38 c€/kWh for 10 more years, whereas an annual limitation of 8PJ biogas must not be exceeded. For all other renewable energy sources the TSO will sell their production on the spot market and the owners receive the market price plus a subsidy of 1,34 c€/kWh. This subsidy is paid by the end-consumers as a CO2 tax of 1,34 c€/kWh and environmentally friendly producers receive that tax.
Natural gas and waste, existing CHP plants	Plants with an output over 10 MW and since 2007 over 5 MW, are responsible for the sale of the production themselves. An individual subsidy, based on the average subsidy they received from 2001-2003, is paid to them monthly without a relation to any output. That means if they produce energy or not, they get a fix amount of money every month, which is index-linked annually. Therefore, they are not eligible for any production-related subsidy anymore. This grant is paid for 20 years since the grid connection, but at least for 15 years since January 1st, 2004. For plants with an output below 10 MW, the TSO will sell their electricity on the spot market and a subsidy together with the spot market price is paid in the form of the three-times-tariff, which is explained in detail afterwards. From 2005 to 2007 plants with output between 5 and 10 MW could decide themselves when they wanted to switch over to the other subsidy scheme.
Natural gas and waste, new CHP plants	They are responsible for the sale of production themselves, and no subsidies are eligible. Neither production related nor a fixed monthly grant which does not depend on the output of the plant is paid.

Multi-fuel CHP plants	A fuel is considered as multi-fuel if it contains between 10 and 94 percent of renewable combustible energy. Plants connected to the gird before April 21st, 2004 eligible for a premium of 3,5 c€/kWh for 20 years since grid connection but at least for 15 years since January 1st, 2004. Plants connected to the grid afterwards are not eligible for any subsidies.

As is mentioned in table 5.1, existing small-scale CHP plants using natural gas or waste are eligible for either the three-time tariff or a fixed, non-production related grant.

The three-time tariff is a fixed tariff per kWh depending on the hour of the day. Consequently, there are three different steps: a low price in the night, a medium price during the afternoon and peak price in the mornings and evenings. The prices in these periods are index-regulated every quarter of a year and depend additionally on the fuel and tax levels. Furthermore, the three-time tariff was developed in order to shift the electricity production of small-scale CHP plants to the period of peak-load. In this case, electricity is mostly produced where it is demanded and less transport in the transmission grid occurs. Therefore, the three-time tariff supports the electricity production costs but as well keeps the grid-tariffs low, due to less transport and therefore less operation costs. An example is given in figure 5.7 to the left.

The fixed annual grant is calculated by the difference between the three-time tariff and the spot market price for a certain period, which is mostly between 2001 and 2003 for each plant itself. This amount of subsidy Q, is divided into twelve parts and with the formula $grant = \frac{Q}{12} * n$ the monthly grant is calculated, whereas n is depending on the spot market price as is shown in figure 5.7 to the right.

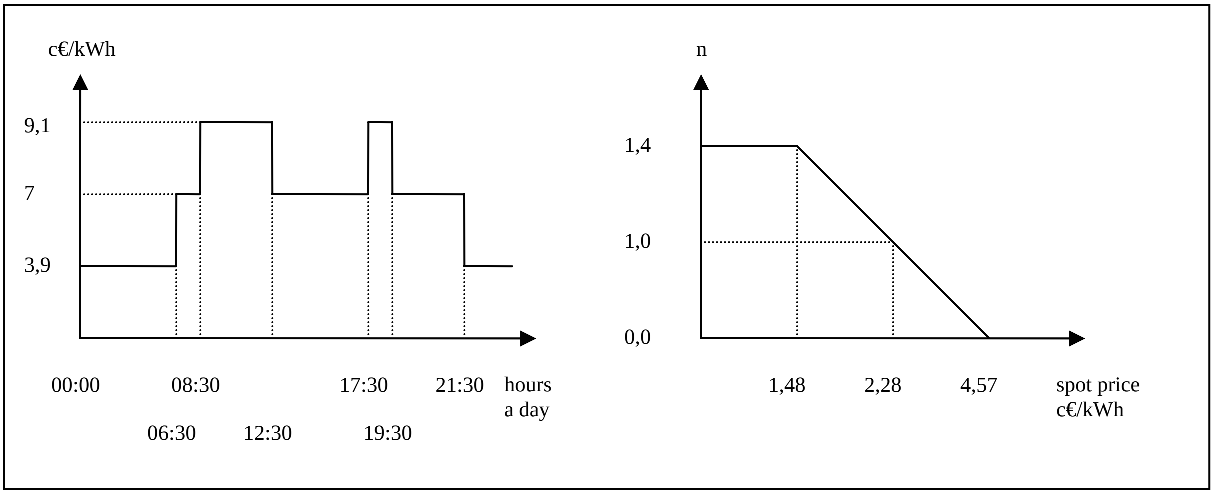

Figure 5.7 Left side: Three-time tariff from last quarter of 2006; right side definition of n in order to calculate the grant at the new subsidy scheme (Koch, J.; 2007).

Like the subsidies paid to wind turbine owners, the grants for local small-scale CHP plants are paid by the consumer through the Public Service Obligation (PSO), which are part of the electricity bill.

The economics of a waste incineration CHP plant are calculated and presented below. In that calculation, a discount rate of seven percent and an amortization period of 15 years are taken into account. Furthermore, the electricity is still sold on the three-time tariff, but unfortunately no data were available about the exact amount of electricity production per tariff step, so an average is used. All the data which are shown in table 5.2 are provided by the power plant owner.

Table 5.2 Data of a 5 MW waste incineration CHP; Source: EnergiGruppen Jylland

5 MW waste incineration CHP plant - Knudmosevarket							
Year of construction:	1994						
Electric power	5	MW	Fuel types				fuel energy 2,8 kWh/kg
Thermal power	10,8	MW	waste	from industry			full-load hours 7845
Annual electr production	26	GWh/a		share	60	%	
Annual heat production	305	TJ/a		input	23.534	t/a	
	84,7	GWh/a			5	t/h	
Total efficiency	85	%			65.895.062	kWh/a	
				costs	-0,04192	EUR/kWh	60,41 EUR/t + 57 EUR/t tax
			waste	from housholds			
Investments costs	25.890.772	EUR		share	40	%	
fuel costs	-0,0395	EUR/kWh		input	15.689	t/a	
	-4.332.886	EUR/a			5	t/h	
annual O&M costs	9.191.224	EUR/a			43.930.041	kWh/a	
				costs	-0,03575	EUR/kWh	43,15 EUR/t + 57 EUR/t tax
Income							
Electricity	0,0797	EUR/kWh	average income of the three time tariff				
heat	12,0824	EUR/GJ					

Due to the fact that the annual electricity and heat generation was only available for the year 2006, they are set as constant for the calculation of the economics of this plant. Furthermore, the inflation rate from 2006 until 2030 is constantly set at 1,8 percent, and the CHP will not switch from the three-time tariff to the new system, because the spot market price cannot be predicted for the entire period of calculations. This is only an approximate example how long it takes until the power plant owner benefits of his investment. The result is seen in figure 5.8 below.

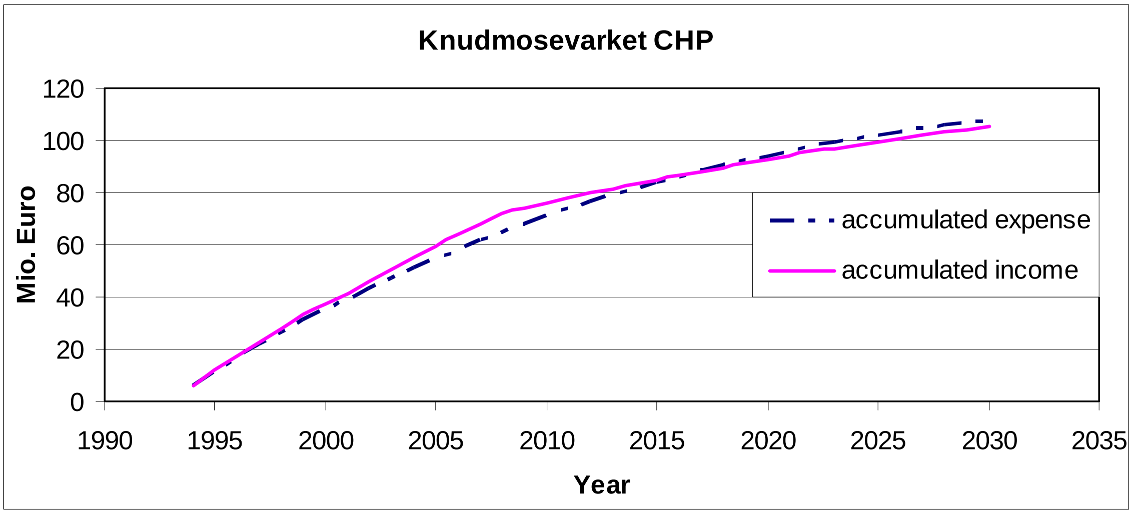

Figure 5.8 Economics of the waste incineration CHP plant in the south east of Denmark

As figure 5.8 shows, it takes 23 years until the CHP plant benefits, although an amortization period of only 15 years is chosen. This is a result of the comparatively high O&M costs of a waste incineration plant, although subsidies for the fuel itself are available[8]. Nevertheless, waste incineration CHP plants are operated because the incomes of fuel from waste previously have been higher and shorter amortization periods were expected. Furthermore, it is committed by Danish law that once a municipal has chosen its kind of CHP plant for its district heating and electricity system, it must not change it. Even in cases when changing the fuel technology would be more economically feasible, it is prohibited.

5.2 Economics of industrial and household CHP plants

Most Danish small-scale CHP plants sell their heat to the connected District heating systems. On the other hand, some small-scale CHP plants are operated in order to serve companies with heat for their processes. Moreover, a few household CHP plants exist too. These plants are very rare in Denmark due to several political influences and therefore only a few are operated in Denmark, as is discussed in the second subchapter.

5.2.1 The Danish situation of industrial CHP plants

The main difference between an industrial CHP plant and a common one, is that the industrial plant runs only on the purpose to meet the steam and electricity demand of the connected industry. The surpluses are sold on the market. Industrial CHP plants are designed as back-pressure CHP plants, with a fixed ratio of producing heat and

[8] Expert interview with a responsible persons at EnergiGruppen Jylland and Dong Energy

electricity whereby additionally the opportunity to extract all the steam and produce no heat exists as well. Due to this advantage they can install a smaller turbine than the industrial maximal steam-load, which results in less investment and operation costs and therefore cheaper generation costs.

Nowadays, about 500 MW of industrial CHP plants are already installed in Demark. In March 1990 the government launched a program to release a potential of 400 MW of industrial CHP plants. Many companies built such a plant in the mid-nineties with power sizes between 5 and 30 MW. In that time a grant of 30 percent on the total investment, including building, turbine and generators, were given to the industries. Researchers realized that the subsidies of this governmental program were most favorable for investors and so the government down-regulated the subsidies; this meant that hardly any new industrial CHP plants were installed anymore. Experts do not expect that more industrial CHP plants will be built in the near future due to the increasing fuel taxes (Hammer, T.; 2005).

The electrical grid connection of industrial CHP plants depends on the annual electricity production. Unfortunately, no exact amount of electricity generation could be found, whether the connection is carried out via a connection line to the high voltage grid, or if it is only connected via the normal consumption line. The boundary is somewhere close to the annual consumption of the industrial company, if the generated electricity is sold via a connection to the high-voltage grid or via the common connection line. In every case, the responsibility for selling the electricity on the Nordic spot market NordPool depends again on the size and the fuel of the plant, as is explained in table 5.1. Moreover, the subsidy scheme for the sold surpluses of produced energy is paid as well in accordance to table 5.1.

The following example will demonstrate the economical feasibility of an industrial CHP plant. This plant serves two different companies with steam, a bio-pellet plant and a furniture company. The steam is sold at 14 bar and at condensing temperature in big pipes connected to the companies, which are very close to the CHP plant. The plant is owned and operated by Dong Energy, one of the biggest energy companies in Denmark. Dong Energy signed contracts with its two mentioned steam customers to provide the required steam.

Table 5.3 Data of an industrial CHP plant in south east of Denmark; Prices in Euro 2006; Source: Dong Energy

Industrial Biomass CHP plant - Koege									
Year of construction:	1987								
Electric power	24	MW	Fuel type				fuel energy	3,8	kWh/kg
Thermal power	81,3	MW	woodchips	share	100	%	full-load hours	5125	h
Annual electr production	123	GWh/a		input	22.000	t/a			
Annual heat production	446,56	TJ/a			4,293	t/h			
	124,04	GWh/a			83.600.000	kWh/a			
Total efficiency	91	%		costs	0,0254	EUR/kWh		7,044	EUR/GJ
Investments costs	48.916.810	EUR							
fuel costs	2.119.968	EUR/a							
annual O&M costs	11.348.700	EUR/a							
Income									
Electricity	0,084	EUR/kWh							
heat	14,021	EUR/GJ							

The levelized electricity generation costs are calculated with respect to table 5.3 and a discount rate of 7 percent and an amortization period of 15 years are taken into account. This results in electricity production costs of 7,14 c€/kWh in the year 2006. As it is mentioned above, these costs are about 35 percent smaller than at common Biomass CHP plants, due to the fact that this CHP plant has less investment costs because it is mainly designed to meet the steam demand of the factories.

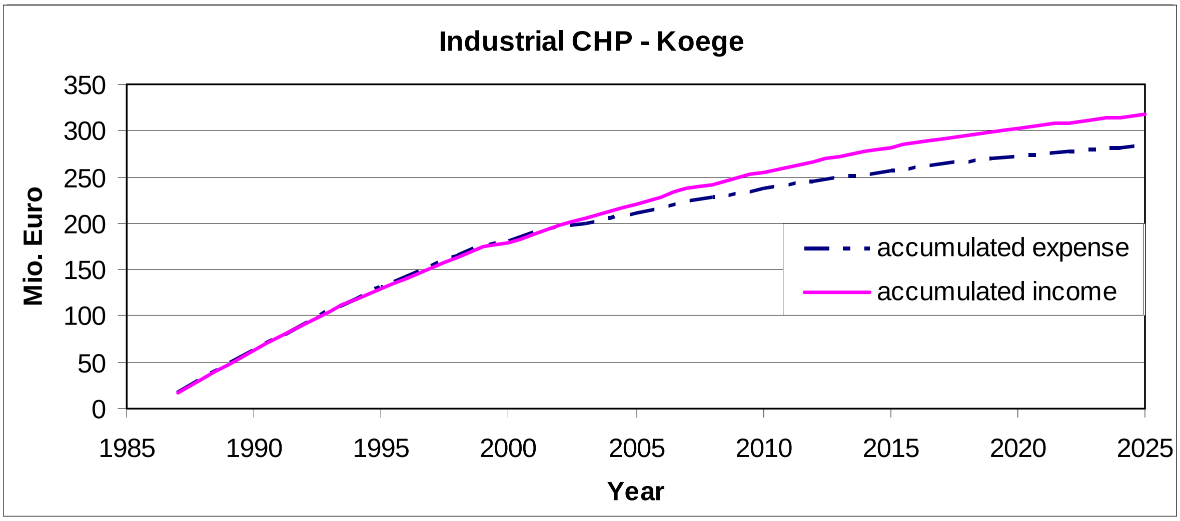

Figure 5.9 Economics of the industrial CHP plant (Prices in Euro 2006); Source: Dong Energy

The calculations in figure 5.9 are based on a constant electricity surplus which is equal to the year 2006 because no detailed information was available. Furthermore, the constant gain in growing since 2004 is mainly caused by too high steam prices, which were negotiated before the plant went into operation. In 2008 new negotiations will take place, and a far smaller tariff is expected per ton of steam; this is not taken into account in these calculations. The CHP plant sells 160.000 tons a year to the two companies[9].

5.2.2 The Danish situation of household CHP plants

Although in the Danish electricity market a lot of small-scale CHP plants are involved, hardly any household CHP plants are operating there. This is mainly caused by two reasons. Firstly, almost all households are more or less obliged to connect to the local District Heating system; this is established in the Executive Order no. 196 of June 1991 and part of the Act on heat supply of 2000. Secondly, household CHP plants up to 100 kW have a comparatively small efficiency factor and, on the other hand, as figure 5.6 indicates, the District Heating system is mostly the cheapest solution for households to buy heat.

Hence, around 80 small villages spread all over Denmark jointly own and operate local small-scale CHP plants with an electrical power of less than 1 MW. Moreover, they own and run a District Heating system as well. In most cases these CHP plants are far out on the countryside where either the natural gas grid crosses the village or the CHP plants run on biomass fuel. Due to the fact the every villager jointly owns the CHP plant and the District heating grid, the investment and O&M costs are spread on 300-400 households, which makes it possible to heat the houses in the cheapest way. The electricity is sold by the TSO on the Nordic spot market, and the CHP owners receive the market price plus the subsidies as it is mentioned above in table 5.1.

In order to demonstrate the economics of such a jointly owned small-scale CHP plant, some calculations are made for a natural gas fired plant in Vorupoer. This village is located in the North-west of Jutland and consists of 340 households. These 340 households jointly own and run the CHP plant as well as the locally installed district heating pipes. In 1994 two 736 kW Jenbacher turbines were installed with a thermal power of each 1100 kW. The investment costs in the district heating grid, 1,5 million Euro, and the profit of the heat distribution, 9,33 Euro/GJ (price in Euro 2006), are not taken into account in this calculation. All the other relevant data are presented in the following table 5.4[10].

[9] Expert interview with a responsible persons at EnergiGruppen Jylland and Dong Energy
[10] Expert interview with a responsible person at the small-scale CHP plant in Vorupoer

Table 5.4 Data of a household CHP in Vorupoer, Prices Euro 2006; Source: Member of the CHP plant

Household natural gas CHP - Vorupoer									
Year of construction:	1994								
Electric power	1,472	MW	Fuel types				fuel energy	11	kWh/m³
Thermal power	2,2	MW	natural gas	share	100	%	full-load hours	4076	h
Annual electr production	6	GWh/a		input	1.300.000	m³/a			
Annual heat production	30,6	TJ/a			14.300.000	kWh/a			
	8,50	GWh/a		costs	0,6	EUR/m³			
					0,0534	EUR/kWh			
Total efficiency	98	%							
Investments costs	1.898.657	EUR		owned by:	340	housholds			
fuel costs	762.915	EUR/a		subscribtion	1173,7	EUR/a			
annual O&M costs	43151,29	EUR/a							
Income				low tariff	medium tariff	high tariff			
Electricity	0,0850	EUR/kWh	three time tariff	0,0501	0,0898	0,1174	EUR/kWh		
heat	11,986	EUR/GJ		32,3	38,5	29,2	% sold on tariff		

The electricity is still sold on the three-time tariff which will have to be switched to the new subsidy scheme until 2009. This fact and the annual production of heat and electricity were only available for the year 2006, which is regarded as constant in further calculations. Furthermore, the heat consumers pay an annual base price according to the square-meter of their household, which is standardized at 914 Euro/year for 130m².

All these influences calculated electricity generation costs of 8,6 c€/kWh, which allows to keep the heat price on an adequate level compared to bigger cities. This CHP plant together with district heating system is a non-profit company too, which means that if they make any profit out of it they will down-regulate the heat price. If the natural gas price stays steady in the future this down-regulation might happen from 2011 onwards, as is shown in figure 5.10 below.

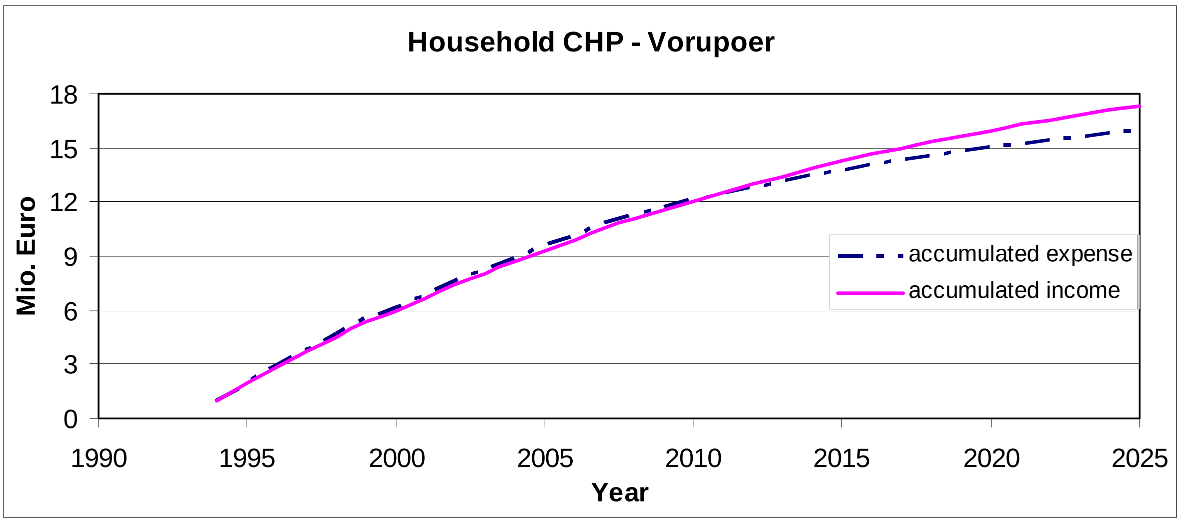

Figure 5.10 Economics of the household CHP plant in Vorupoer; Prices in Euro 2006

5.3 Grid integration of small-scale CHP plants

In this chapter the different issues to connect local CHP plants to the distribution grids are discussed. Firstly, a short overview of the most relevant factors of grid connections is presented and the connection obligations are discussed as well. Furthermore, the connection costs of integrating a small-scale CHP plant are calculated and the main parts are explained. Finally, the methods of socializing the grid connection costs are explained and an example is shown.

5.3.1 Implementation of grid connection

Since almost all small-scale CHP plants have only a few MW electrical output, they are mostly connected to the distribution grid as wind turbines are as well. Therefore, the legislations for grid connection are similar although a few aspects have to be taken into account in connecting small-scale CHP plants.
As wind turbines in Denmark can be erected everywhere, small-scale CHP plants are only built up close to villages with a district heating system in order to be able to sell heat and electricity, because otherwise the income would not cover the expenses. This fact limits the possible places for CHP plants and therefore the heat demand regulates the amount of installed and grid-connected small-scale CHP plants. Nowadays, almost all District Heating systems are covered by CHP plants and therefore experts do not expect that more CHP plants will be built. A new grid connected CHP plant would require a new District Heating system in a town, which covers the current heat demand by private heating.

Nevertheless, it is easy to receive the permission to erect a small-scale CHP plant in Denmark if the right place is found. Therefore, it is only necessary to get an approval after the Act on Electricity Supply and after the Act on Heat Supply. Furthermore, if the CHP plant is planned to run on natural gas, an approval after the Act on Emissions is also obligatory. The latter Act points out the maximum amount of emissions a power plant is allowed to produce. This amount depends on the power size of the CHP plant, whereas the smaller it is the more emissions are allowed to be produced. Biomass fired CHP plant are regarded as free of emissions (Pedersen, S.L.; 2007).

Within the Act on Electricity Supply, in paragraph §67 it is determined who bears which part of the grid connection costs of small-scale CHP plants and table 5.5 gives an overview on the connection rules.

Table 5.5 Connection rules for small-scale CHP plants Source: Act on Electricity Supply §67

General grid - connection rule	The owner of the decentralized CHP plant shall bear all costs which would appear if the CHP plant gets connected to the closest 10 kV node; it does not matter where it gets connected physically. These costs include a transformer from the voltage level of generation to 10 kV. All the other costs, like reinforcement or extensions in the grid are to pay by the Distribution System Operator, who decides where the CHP plant gets connected, regarding the technical issues.
CHP owners want to be connected to a certain voltage level	In case that the owner of the CHP plant wants to supply electricity at a higher voltage level than 10 kV, he has to bear all the costs which appear to the real physical connection point and the System Operator only bears the costs of reinforcement and extensions of the distribution grid.

5.3.2 Grid connection costs of small-scale CHP plants

Since the grid connection costs of small-scale CHP plants are divided between the plant owners and the local Distribution System Operators according to table 5.5 in this subchapter, only the costs of the Distribution System Operator are discussed. The smaller part of the grid connection costs, which are borne by the plant owners, are included in the investment costs and are therefore taken into account in the chapters before.

The Distribution System Operators who are responsible for the grid extensions and reinforcements are mostly operating three different voltage levels between 10 kV and 60 kV. Thus, small-scale CHP plants have an average electrical output of less than 10 MW. They are connected to the 10 kV grid where also most changes happened compared to the other grids. Only a few CHP plants are connected directly to the 60 kV grid, whereas in these cases, according to the Act on Electricity Supply §67, the Distribution System Operator is only responsible for the reinforcement of the grid, which usually had not to be done due to a strong 60 kV grid.

In general, changes of the grid topology due to connecting small-scale CHP plants have not been observed as it has been done in the connection of wind turbines. This fact is mainly based on two reasons.

Firstly, small-scale CHP plants are uniformly distributed in Denmark and no certain areas with higher penetration of small-scale CHP plants exist. In order to erect a new CHP plant, a heat demand in the closer surroundings is required; this limits the number of new CHP plants in each area. Therefore, in the area of one Distribution

System Operator only a few small-scale CHP plants run and once they are connected to the grid they are working for 30 years and more, whereas in this period no new plants are necessary.
Secondly, small-scale CHP plants are set up closer to the city as wind turbines because they do not require a free landscape without any surroundings. Also, a CHP plant has to be as close as possible to the District heating distribution system in order to avoid big losses of heat. Moreover heat pipelines are much more expensive than the electrical grid connection, therefore short connection lines to the District Heating System are favorable. Thus, the 115 different Distribution System Operators only had to extend their grids between half a kilometer and two kilometers within a period of 30 years (Larsen, N.O.; 2007).

Due to these reasons, the impact of small-scale CHP plants on the distribution grid enlargement has not been as big as the impact of wind turbines. Nowadays, about 600 small-scale CHP plants are grid-connected, as is shown in figure 5.11.

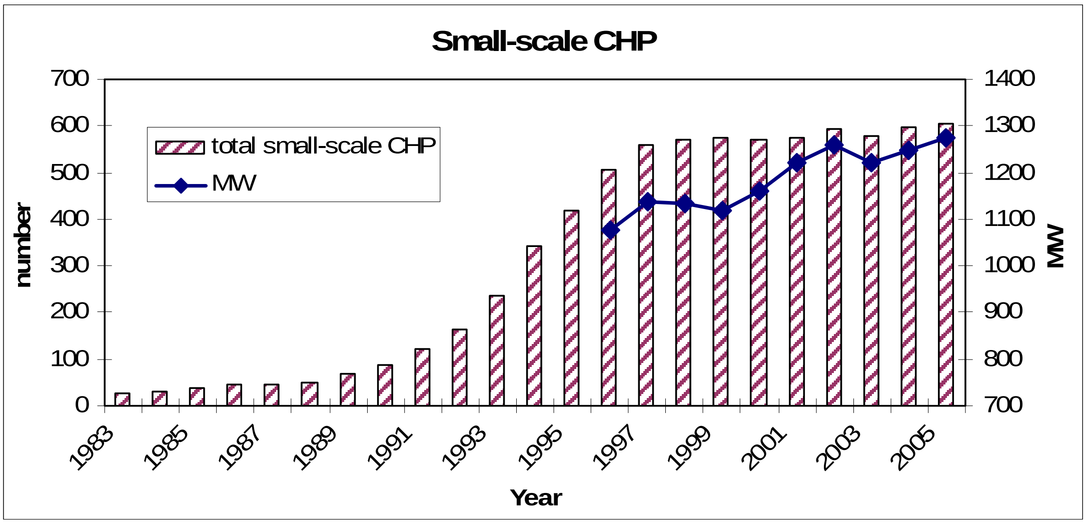

Figure 5.11 Total grid connected small-scale CHP plants on the left scale and their accumulated capacity on the right scale; Source (Statistics Denmark, 2006)

Figure 5.11 illustrates that most of the small-scale CHP plants were set up in the nineties and 606 plants were grid-connected in the year 2005, with an accumulated electrical output of 1273 MW. Due to the fact that every Distribution System Operator runs only a few small-scale plants, no data was available of the total distribution grid extension. Nevertheless, since small-scale CHP plants are located close to the city, a total grid extension of 800 km is expected due to the influence of CHP plants (Hübbe, C.; 2007). These 800 km are only four percent of the total distribution grid enlargements in Denmark in the period between 1990 and 2000.

As the grid connection costs for wind generators depend mainly on the distance of theconnection line, the installed capacity is the most important parameter for small-scale CHP plants, because the distance is in the same range for every CHP plant. Figure 5.12 provides a cost allocation of the grid connection costs depending on the power size of the plant.

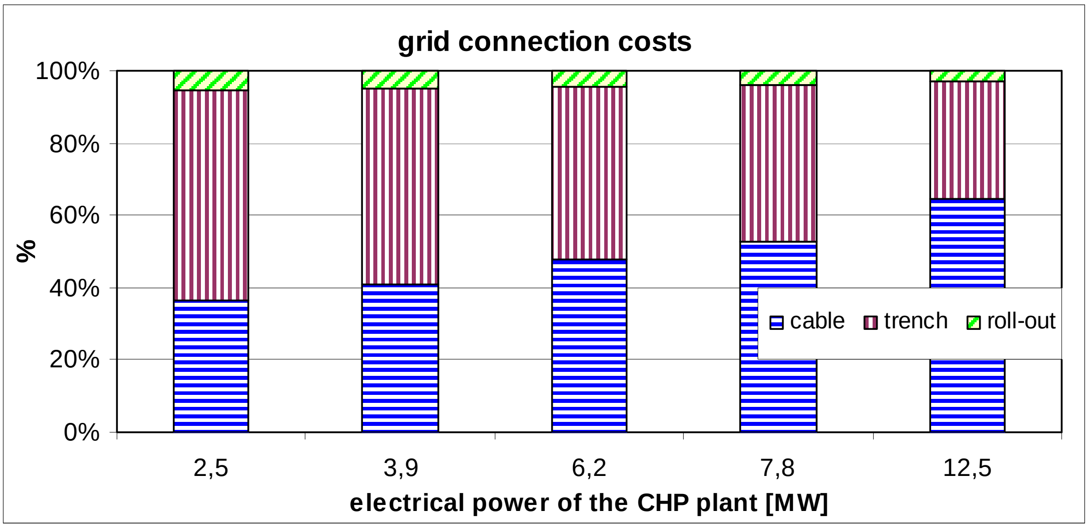

Figure 5.12 Grid connection cost allocation for small-scale CHP plants (Larsen, N.O.; 2007)

Figure 5.12 points out that the grid connection costs for the Distribution System Operators of CHP plants with a smaller electrical output are dominated by the costs of digging the trench, whereas with an increasing capacity the cable price is dominating the overall costs. As most of the small-scale CHP plants have an output of only a few MW, and are installed in villages with a small heat demand, they got connected to the distribution grid by over-head lines in order to avoid the digging costs. In the nineties, when most of the small-scale CHP plants were built, over-head lines were still increasing until they started to get substituted by cables in the late nineties. On the opposite side, CHP plants with a higher output are mostly erected in bigger towns or cities and are therefore connected by cables; thus, in cities no over-head lines are set up. An increasing cost of copper lead to the use of aluminum cables only in order to keep the total costs as low as possible.

Furthermore, the Distribution System Operator is obliged to reinforce the 10 kV/60 kV transformer stations in order to handle the new power flow. Thus, because more than 90 percent of the small-scale CHP plants have a small electrical output very few reinforcements had to be made in the transformer stations. A total of seven 60 kV transformer stations got reinforced in order to add a 10 MW or 16 MW transformer in the existing stations, and four more transformers got equipped with a new cooling system in order to increase the nominal power. Adding a cooling system increases the nominal power of a transformer about 27 percent and causes almost 15.000 Euro/MW increased power. On the other hand, a new 10 MW transformer causes costs of about 250.000 Euros and a 16 MW transformer 350.000 Euros. Therefore, the Distribution System Operators always try to build new small-scale CHP plants at a location close to a strong grid node in order to avoid investments in new transformer stations. This happens in regard to the fact that the plant must be set up close to the District Heating system too (Larsen, N.O.; 2007).

The impact of small-scale CHP plants on the transmission grid is very little. Primarily the Danish transmission grid is designed very strong because Denmark is considered as a transit country of electricity. On the other hand, small-scale CHP plants are very uniformly distributed all over the Denmark and the generated electricity was most demand in the same area without the need of transport into the transmission grid. This is organized by the Transmission System Operator in order to avoid transmission losses and operation costs. Therefore, no changes in the transmission grid are observed due to grid-connections of small-scale CHP plants (Helstrup, N.E.; 2007).

Finally, an example demonstrates the total costs of grid connecting a multi-CHP plant to the 10 kV distribution grid. The CHP plant has an electrical output of 13,9 MW and is connected via two 3x240 mm^2 AL cables. The small-scale CHP plant is, compared to others, set up far out of the town and therefore a connection line of 2.184 meters has to be installed. Furthermore, the grid connection line crosses a rail track, which required to dig a tunnel below it and caused additional costs. Because the CHP plant has an electrical output of 13,9 MW the transformer-station had to be reinforced; an additional 10 MW transformer has to be set up. The calculation is presented in table 5.6 below.

Table 5.6 Connection costs of a 13,9 MW multi-fuel CHP plant 2.184 meters apart from the 10 kV grid with an additional 10 kV/60 kV transformer, Prices in Euro 2006

13,9 MW multifuel CHP in 1999		
connection line	costs EUR/m	length m
trench city	83,18	240,24
trench country	23,76	1.943,76
cable	29,65	2.184,00
cable roll-out	2,69	2.184,00
transformer station		EUR
special equipment		11.027,29
Additional transformer of 10 MW		237.225,00

Installed capacity	13,9	MW
cable typ	2x(3x240mm^2)	AL
	EUR 2006	%
trench costs	77.202,53	16,94
cable costs	129.524,85	28,42
cable-roll out costs	11.743,59	2,58
total line costs	218.470,96	47,94
transformer costs	237.225,00	52,06
total connection costs	**455.695,96**	**100,00**

Although this CHP plant required reinforcing the transformer station, the specific grid connection costs in EUR/MW are only half of the specific costs of the wind park presented in table 4.5 due to shorter connection lines and higher electrical output.

5.3.3 Socialization of grid connection costs evolved by small-scale CHP plants

Although small-scale CHP plants are almost uniformly distributed in Denmark compared to wind generators, there are differences in the grid connection costs between the individual areas. These differences would lead to an unfair local grid tariff allocation and therefore the Act on Electricity Supply number 286 regulates the sharing of these costs. In paragraph §8 it is determined that the same method is used to share the grid connection costs for small-scale CHP plants like for wind turbines. Furthermore, the difference between the refunds from the Transmission System Operator to the Distribution System Operator and real investments in the grid connection has to be covered by the local grid tariffs.

In order to estimate the expenses for grid-connecting a small scale CHP plant, another model is applied than for wind generators. The main difference between these two models is the estimation of the cable price, which is considered higher for connecting a CHP plant. This higher cable price is justified by a higher utilized capacity; thus, small-scale CHP plants have much higher full-load hours than onshore wind turbines. The model is determined in the bye-law NOTAT 02-001e which is in operation since January 1st, 2007 and is explained in table 5.7 below.

Table 5.7 Refunding model for grid connection expenses of the individual Distribution System Operators in action since January 1st, 2007 following the NOTAT 02-001d Prices in Euro 2006; Source: Danish Transmission System Operator – Energinet.dk

$refund = baseprice + (cableprice + trenchprice) * length * 1{,}1$		
base price	CHP plants smaller than 2 MW, connected to any node in the 10 kV grid	4.032 EUR
	CHP plants between 2 MW and 5 MW, directly connected to a 10 kV/60 kV station	48.388 EUR
	CHP plants between 5 MW and 10 MW, directly connected to a 10 kV/60 kV station	96.776 EUR
	CHP plants between 10 MW and 15 MW, directly connected to a 10 kV/60 kV station	145.163 EUR
	CHP plants between 15 MW and 20 MW, directly connected to a 10 kV/60 kV station	193.550 EUR
	CHP plants between 20 MW and 25 MW, directly connected to a 10 kV/60 kV station	241.938 EUR
Cable price	$cableprice = (9{,}409 * P[MW] + 9{,}409)$	EUR/meter
trench price	Digging price in the city	53,67 EUR/meter
	Digging price on the countryside	16,13 EUR/meter

Table 5.7 presents the different parameters of the calculation of refunding the grid investments due to connecting a small-scale CHP plant to the grid. In the case of grid reinforcements, the refunds are determined by the total refunds of the new capacity minus the refunds of the already existing capacity. The NOTAT 02-001e is in operation since January 1st, 2007 and followed the NOTAT 02-001d. The old NOTAT 02-001d allocates the same refunds except the digging of a trench; it was considered to be much cheaper and only nine Euros were calculated per meter, regardless the location of the trench.
In addition to the refunds from the connection lines, the Distribution System Operators are also eligible for refunds of the investments they made in their 10 kV/60 kV transformer stations. This model is the same model as is used at the refund estimation of wind turbines and is presented in table 5.8 below.

Table 5.8 Refunding model for transformer station expenses of the individual Distribution System Operators in action since January 1st, 2007 following the NOTAT 02-001d Prices in Euro 2006; Source: Danish Transmission System Operator – Energinet.dk

Add cooling system	reinforce / replace station
$refund = 13.414 * (S_{new} - S_{actual})$	$refund = 26.882 + 24.865 * (S_{new} - S_{actual})$
$S_{new} = \sqrt{P^2_{wind,total} + Q^2_{wind,total}}$ $S_{actual} = S_N$ of actual wind capacity	
Nominal sizes of transformers: 8 MVA, 13 MVA, 20 MVA 31,5 MVA	Nominal size of transformers: 6,3 MVA 10 MVA, 16 MVA, 25 MVA

The formulas in table 5.8 always consider the nominal powers of the next bigger transformer as the load capacity requires. Furthermore, these refunds for the connection line and transformer stations do not reflect any real investments in the distribution grids due to the connection of new small-scale CHP plants. The real expenses are in most cases higher than the refunds, although in a few cases the whole costs are covered by the refunds or even a little surplus appears for the Distribution System Operators.

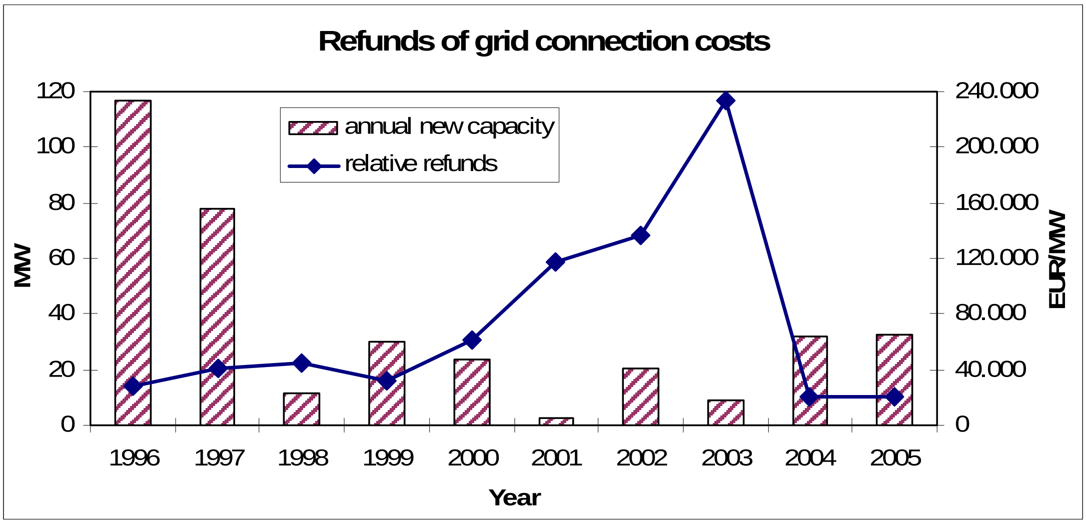

Figure 5.13 Capacity of annual installed small-scale CHP plants on the left scale and annual refunds per capacity in Euro2006/MW on the right scale for the changing grid topology

Figure 5.13 presents the annual installed capacity of small-scale CHP plants and the relative refunds of the expenses made in its grid connection. These refunds do not reflect the real investments in the distribution grids, so they are only paid in accordance to the model of table 5.7 and table 5.8. Furthermore figure 5.13 shows that in the mid-nineties, the refunds have been comparatively small due to the fact that the small-scale CHP plants are set up close to the district heating systems and therefore close to a possible electrical grid connection point as well. The relatively high refunds in the beginning of the present century are caused by only a few newly installed CHP plants which are erected further apart from the existing distribution grids. A comparison between the relative refunds of grid connection between wind generators and small-scale CHP plants results in a lower average refund of grid connection of small-scale CHP plants, because the distribution grid topologies are more strongly influenced by connecting new wind turbines to it.

As in the case of wind generators, the same procedure applies for small-scale CHP plants. All expenses the Transmission System Operator has to make in order to refund the costs of the individual Distribution System Operators, are covered by the Public Service Obligations (PSO). The PSO are adjusted by the TSO every three months and are collected monthly at the electricity bill of the end-consumers. Therefore, the PSO covers the subsidies of renewable energy generators as well as the investment in the distribution grids which are made in order to connect them to the grid. Thus, the PSO are determined by the Transmission System Operator, every electricity consumer bears exactly the same part of the investments. So a fair pricing system is implemented (Helstrup, N.E.; 2007).

The Act on Electricity Supply number 286 determines in paragraph §8 in the fifth part, that the differences between the real grid investments and the total refunds have to be covered by the local grid tariffs. Thus, it is only allowed to earn a little profit for the local Distribution System Operators if they are one of the most cost efficient operators, the grid tariffs are calculated by the rest of the investments in the grid using a 30 years amortization period and the O&M costs of the System Operator itself. Depending on theses parameters, the grid tariffs vary within the individual System Operators. All distribution grid tariffs have to be permitted by the Danish Energy Regulatory Agency (DERA) before they are taken into account in billing processes.

The following example points out how the refunds of the multi-fuel CHP plant of table 5.6 are calculated in accordance to the model presented above. Here, it is to mention that before the CHP plant got grid connected, only one 16 MW transformer was operating in this 10 kV/60 kV station and the total load capacity was 10,8 MW. In order to add the CHP plant at this connection point, a new 10 MW transformer in the same station got erected; this is considered as a reinforcement of the transformer station.

Table 5.9 Refunds of the 13,9 MW CHP plant of table 4.6, 2184 meters apart from the 10 kV grid including a new 10 MW transformer in the existing station; Prices in Euro 2006

13,9 MW multifuel CHP in 1999				Installed capacity	13,9	MW
connection line	costs EUR/m	length m		cable typ	2x(3x240mm^2)	AL
					EUR 2006	%
trench city	63,26	124,05				
trench country	18,98	702,95		trench refunds	21.187,99	5,03
cable	164,95	827,00		cable refunds	136.414,02	32,41
transformer station		EUR		total line refunds	157.602,01	37,44
refunds of a 25 MW trafo		763.073,75		transformer refunds	263.319,75	62,56
refunds of a 16 MW trafo		499.754,00		total connection refunds	420.921,76	100,00
resulting refunds		263.319,75		total connection costs	495.233,46	100,00
costs to cover by the DSO					74.311,70	15,01

The closest possible connection point of this multi-fuel CHP plant would have been only 827 meters away from the CHP plant, therefore only this distance is taken into account in the calculations in table 5.9. Furthermore, a new 10 MW transformer was set up, but the refund system considers it as a reinforcement of the transformer station. Therefore, only the difference between the existing nominal transformer power and the required nominal transformer power is taken into considerations. Finally, the Distribution System Operator had to bear fifteen percent of the total investment costs and the rest was covered by the PSO.

6. The Austrian Electricity System – Integration of RES-E

The Austrian electricity system is divided into three responsible areas, whereas these areas are structured in several balancing groups. Therefore the complex organizational structure is discussed in detail within the first subchapter where the relation between the single market participants and their responsibilities and obligations are explained. In a further part the focus is laid on the balancing situation of the Austrian electricity market and the related costs. The final chapter explains the historical development of this organization and points out the underlying legislations in order to promote RES electricity generation.

6.1 Organizational structure of the Austrian Electricity System

The organizational structure of the Austrian electricity system of nowadays is explained in this subchapter. The main market participants and their responsibilities are introduced and discussed. Furthermore, the Austrian pricing method of renewable energy is presented as well.

The Austrian law on Electricity Supply, (ELWOG), of 1998 required the introduction of control areas[11] in the transmission grid. Therefore, the grid is divided into three control areas, the VKW in Vorarlberg, the TIWAG in Tyrol and the APG in the rest of Austria. This classification arose from a historical point of view, when the transmission grid in Vorarlberg was built together with the Italian grid and the Tyrolean grid together with to the German transmission grid. The APG is the biggest control area within Austria with an electricity consumption of 85 percent of total Austria (Weißensteiner, L.; 2005).

Because the transmission grid is divided into these three control areas the Transmission System Operator is the particular control area administrator[12] responsible. These administrators are mainly responsible for the electricity exchange among each other and the operation of their power plants in order to follow the scheduled plans (Auer, H.; 2007).
A further function of the control area administrator is to manage the ecological balancing group[13] within his control area.

Each of the control areas consist of several balancing groups[14] and one responsible balancing group coordinator[15] for the balancing energy of its related groups. A

[11] In the Austrian law called Regelzone
[12] In the Austrian law called Regelzonenführer
[13] In the Austrian law called Öko-Bilanzgruppe
[14] In the Austrian law called Bilanzgruppe
[15] In the Austrian law called Bilanzgruppekoordinator

balancing group is a financial union, within which power supply companies and traders act together. Furthermore, balancing groups are independent of the geographical situation and are launched in order to trade electricity internally or with other balancing groups and control areas. In case of deviations from the planned schedule of generation and demand within the balancing group, it is necessary to buy regulative electricity from other balancing groups within the control area. Due to technical standards it is not possible to launch a balancing group in two different control areas.

As is mentioned above, in each control area one eco-balancing group is installed. This eco-balancing group is responsible for the total renewable energy within its control area. Only five percent of renewable energy in Austria are not part of the eco-balancing group but feed into regular balancing groups, hence no subsidies are paid. Furthermore, every balancing group has to sell their customers a certain percentage of renewable electricity according to the ELWOG of 2001. This percentage amounts to four percent in 2007. Thus, all renewable electricity generators financially feed into the eco-balancing group. The other balancing groups are obliged to buy renewable energy of at least this percentage of their total consumption at a pre-defined price[16]. This pre-defined price amounts to 4,5 c€/kWh in 2007 and is defined by law. If the balancing groups buy too little renewable electricity, they have to pay a fine of 4,5 c€/kWh according to the law. The disadvantage of the fix percentage of renewable energies the balancing groups have to sell is that they buy only the obligatory amount but not more, even in the case when more renewable energy might be generated (Auer, H.; 2007a).

Thus, renewable electricity generation is subsidized, different sources allocate these payments. In order to cover the difference between the feed-in tariffs of wind energy and biomass CHP plants which are part of the eco-balancing groups, all regular balancing groups buy their renewable energy at the pre-defined price, a little above the market price. This difference is spent on administration and balancing expenses. On the other hand, the customers pay an additional green-surcharge with their grid utilization tariff. This tariff varies over time and is collected by the Distribution System Operators. Every three months the System Operators remit the money to the concerned eco-balancing group. Figure 6.1 below shows the allocation of the feed-in tariffs.

[16] In the Austrian law called Verrechnugspreis

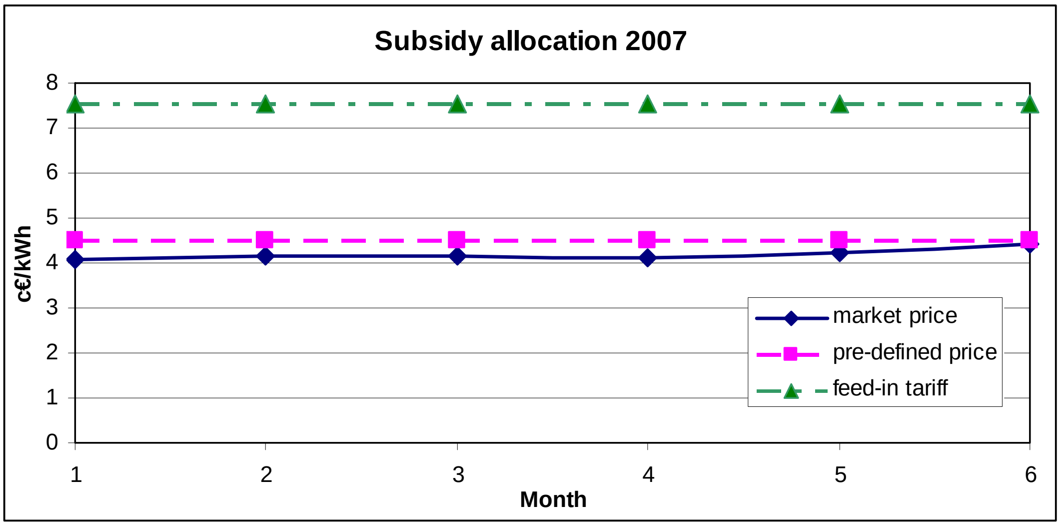

Figure 6.1 Subsidy allocation for wind energy in the year 2007; Source: (E-Control, 2007)

In order to calculate the green-surcharge on the costumer's electricity invoices, all renewable energy technologies have to be taken into account because, as is explained in the following chapter, biomass CHP plants are eligible for higher feed-in tariffs as wind turbines. Expenses for further subsidies as investment grants are partly covered by the incomes of fines in case of a too small percentage of renewable energy in a balancing group. Furthermore, the Austrian government allocates a fixed annual amount of money for subsidizing renewable energy.

Thus, every balancing group has to sell the fixed percentage of the total electricity consumption within its group on renewable energy a measuring institution is required. Therefore, the Distribution System Operators are measuring the electricity generation of their connected power plants and portion it to the related balancing groups. Furthermore, the electricity consumption of the System Operators clients is measured and reported to the related balancing groups as well. In this way it can be controlled if each balancing group sold enough renewable electricity to their customers. The Distribution System Operators charge an annual fee for measuring.

Generally, it is the control area administrator's responsibility to follow the planned schedule within his area. The Austrian electricity law "ELWOG" regulates that the balancing group responsible has to mention the schedule[17], in steps of fifteen minutes one day in advance, to the balancing group coordinator. Three different schedules are distinguished. There exists an internal schedule for energy exchange within the control area and an external schedule for power exchange with other control areas or other countries. In order to calculate the required balancing power, the control area administrator needs one total schedule of each balancing group. Furthermore, the control area administrator approves the external schedules and in

[17] In the Austrian law called Fahrplan

case of grid-bottlenecks it decides which exchanges are possible and which are denied.
Figure 6.2 below illustrates the organization of the different market participants on the Austrian electricity market.

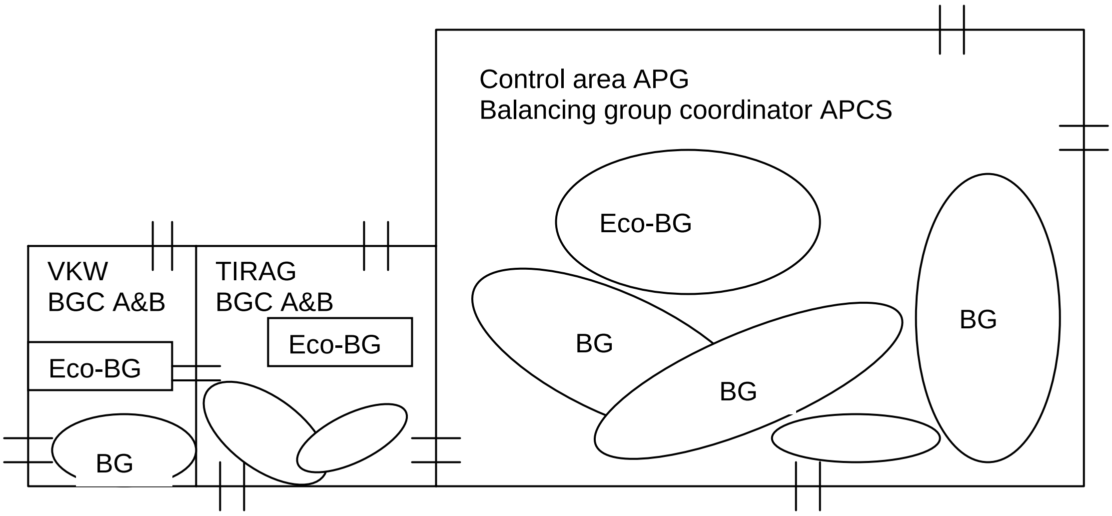

Figure 6.2 Organizational structure of control areas, balancing groups and exchange lines (Weißensteiner, L.; 2005)

6.2 The organization of the balancing market

In case of deviation from the planned schedule of generation and demand within a balancing group regulative energy is required. It is the function of the responsible balancing group manager to develop schedules in order to avoid such deviations. In the time of operation it is the balancing group coordinator who activates power plants in different balancing groups in order to balance the whole control area.

As it is mentioned above, it is distinguished between internal schedules and external schedules. Internal schedules are applied by the balancing group responsible in order to inform the balancing group coordinator about internal power exchange and utilization of the infrastructure. This information supports the balancing group coordinator to activate regulative power at the right place in order to avoid bottlenecks in the grid. The internal schedules have to be sent to the balancing group coordinator one day in advance and before weekends it has to be sent on the Friday before. The eco-balancing group faces a big disadvantage in this system due to their high penetration of fluctuating power generators as wind turbines. In order to forecast the wind generation output for the following three days errors up to 45 percent might arise, resulting in higher regulative power demand.

External schedules are applied by the balancing group responsible directly to the control area administrator. These schedules in steps of fifteen minutes consist of bilateral agreements between traders and retailers and notification on the European Energy Exchange EEX stock market or the EXAA stock market in Austria. Notifications on the stock markets have to be made until noon and two hours later the stock market publishes the approved notifications (Obersteiner, C.; 2007).

As three control areas exist in Austria, the APG holds 85 percent of the total energy delivery. Within the APG area the balancing group coordinator is the Austrian Power Clearing and Settlement (APCS) institution. On the one hand, the APCS is responsible for the technical power clearing. With respect to the received schedules of its balancing groups the APCS activates and deactivates the nominated regulative power plants on demand in order to balance the whole control area. On the other hand, the APCS is responsible for the financial clearing of the market. This function includes the inquiring of demand on regulative power as well as identifying the clearing price every fifteen minutes. Furthermore, the APCS sends the invoices every month to its balancing groups whereby the balancing groups invoice their customers according to measuring results of the Distribution System Operator.

In order to calculate the accumulated regulative electricity of a balancing group within one month, the planned schedules of generation and demand are compared to the actual generation and demand in steps of fifteen minutes. Furthermore, the clearing price is defined in fifteen-minutes-steps as well, and is multiplied with the momentary energy amount. The result is the cost of balancing energy of the specific balancing group.

The method in order to calculate the momentary balance energy clearing price was changed in the year 2005. The former system depended only on the energy derivation from the neutral position of the control area. Therefore, balancing groups with high energy consumption and generation could influence the market. The case of a surplus within the control area resulted in a negative clearing price. If a balancing group could establishes a temporary lack of energy in their group, they could earn money. The same happened in times of a lack within the control area, resulting in positive clearing prices and a surplus in the balancing group. In order to avoid the speculations of balancing groups which leaded to inefficient utilization of the grid, a new method was introduced in 2005.

The new method is based on a socialized base price and quadratic changes depending on the derivation of the neutral position. In case of big derivations a limit is introduced, depending on the socialized base price. This base price and the limit are calculated every fifteen minutes, depending on the present market conditions. Therefore, the lowest clearing price is achieved if the control area is in the neutral position, leading to an efficient utilization of the grid. Furthermore, speculations are avoided, thus an energy lack in the control area still causes a positive clearing price and balancing groups have to pay money to the balancing group coordinator, instead of receiving money as happened in former times.

Figure 6.3 below illustrates the new clearing price model.

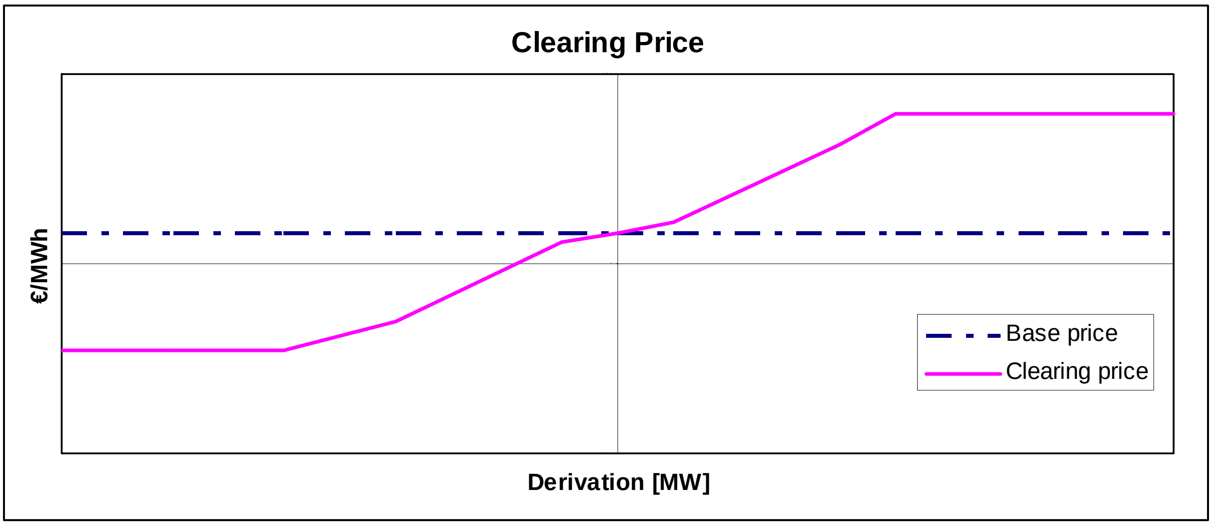

Figure 6.3 Clearing price model in operation since 2005; Source: (Weißensteiner, L.; 2005)

The limits and the base price of the clearing price are influenced by the notifications of the power plants. Each power plant has to inform the balancing group coordinator about the amount and price of energy that it provides for regulative power for every fifteen minutes. Depending on this information, the balancing group coordinator issues a merit order and the clearing prices. The notifications are made in two different ways, whereby a base power is provided for a fixed amount over a long time and additionally required regulative power is sold at pre-defined but varying prices.

In order to be accepted at the Clearing market, some technical requirements have to be met. Only power plants which are able to change their generation within fifteen minutes on a certain level up or down are allowed to provide regulative power. Furthermore, a minimum power output of ten Megawatt is obligatory. This discriminates renewable energy because most of them have a smaller nominal power and no joint ventures are admitted at the regulative power market (Obersteiner, C.; 2007).

6.3 Deployment of legislation favoring RES-E

This subchapter distinguishes between legislations and directives promoting the electricity generation of renewable energy sources and the regulatory criteria in order to grid connect this kind of electricity generators. The historical development of the legislations is compared to the achieved results to be able to discuss the effectiveness of the Austrian system.

6.3.1 Regulatory criteria to promote RES-E generation

In 1947 the Second Nationalization Law was passed by the Austrian government in order to regulate the electricity market conditions and the organizational structure. This legislation was decreed on February, 19th 1997 by the Austrian law: "Elektrizitätswirtschafts- und organisationsgesetz (ELWOG)", including the directive: "Elektrizitätsbinnenmarktrichtlinie 96/92EG". The main aims of this law were to gradually open the electricity market and introduce the Third Party Access (TPA). Furthermore, the law determined that at least 51 percent of the power utilities should remain under public ownership. Moreover, all power supply companies were asked to buy at least three percent of their electricity from non-hydro, renewable energy sources as for instance wind or biomass (OECD; 1998).

In 1999 a further amendment of the ELWOG was introduced in order to support the opening of the electricity market, until the amendment of 2000 determined a hundred percent opening of the market with October 1st, 2001.
On September 27th, 2001 the EU Directive 2001/77/EC was passed, whereby a goal of having 78,1 percent of gross electricity consumption from renewable energy sources was established. As of January 1st, 2002, electricity suppliers must get at least eight percent of their power from small-scale hydropower station, defined as plants below ten Megawatt. Furthermore, electricity supply companies are obliged to buy renewable electricity from non-hydro power plants according to the following schedule: 1 percent in 2001, 2 percent in 2003, 3 percent in 2005 and 4 percent in 2007.
Since 2003 a new amendment of the Austrian electricity law (ELWOG) is published annually, including the main purposes like supporting new renewable energy generation. The EU Directive 2003/54EG promoted the security of supply, the cost effectiveness and the environmental compatibility as well as the social compatibility. Furthermore, subsidy schemes of renewable energy sources are provided within these amendments of the (ELOWG). In Austria, generation subsidies are paid as feed-in tariffs and in certain cases an additional premium is eligible as well. Supplementary different kinds of renewable energy generators receive investment

grants as well. A detailed explanation of this subsidy scheme is given in the following chapter (OECD; 2002a).

When the feed-in tariffs are above the market price the difference is provided by two payments. On the one hand, the responsible balancing groups pay the generators a price above the market price, the settlement price, and on the other, hand the customers pay a green-surcharge per consumed kWh in order to cover the subsidy costs.

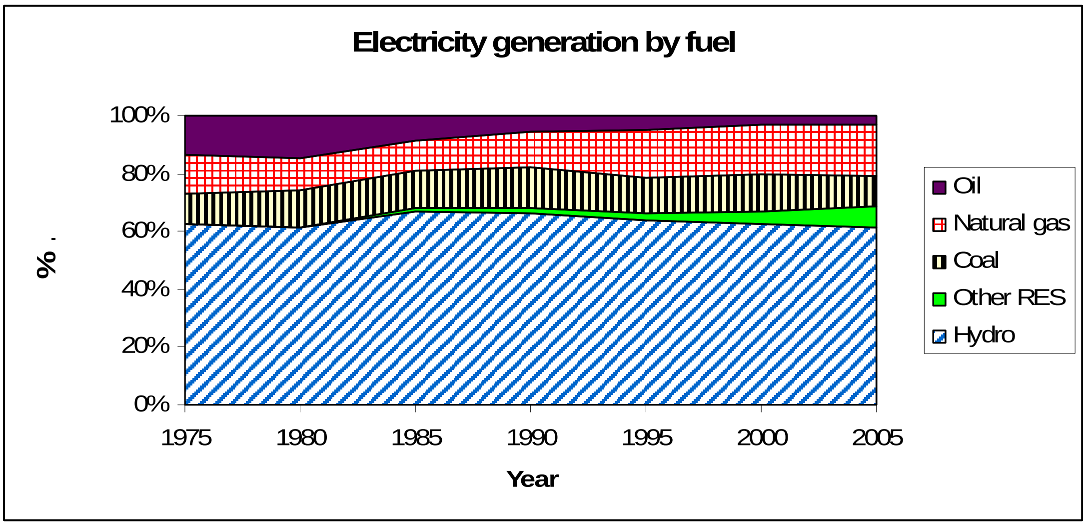

Figure 6.4 Austrian electricity generation sorted by kind of fuel in percent of demand; (OECD, 2002a)

Figure 6.4 illustrates the percentage of different kinds of fuel in the electricity generation. A constant growth of electricity consumption has to be taken into account covered by an increasing share of natural gas and other renewable energy sources whereas the share of large-scale hydro power plants is constant. Although the goal of three percent of other renewable energy source is achieved, a total share of 78,1 percent is not realized yet.

6.3.2 Regulatory intervention in RES-E grid connection

In order to integrate renewable energy sources successfully into the electricity market, it is not enough to subsidy only the generators. Generally, two different approaches exist in order to share the costs of grid connecting new electricity generators. Austria implemented the Deep Cost Approach, a procedure that is not as favorable for renewable energy as the second opportunity, the Shallow Cost Approach.

The Austrian grid consists of a 380 kV and a 220 kV transmission grid, and several distribution grids on voltage levels of between 0,4 kV and 110 kV. The transmission grid is owned and operated by three different Transmission System Operators and the distribution grids are mainly owned and operated by the nine federal Distribution

Grid Operators. These operators are responsible for a reliable and stable grid and therefore different connection rules are implemented among them (VEÖ, 2007).

Generally, the Deep Cost Approach says that the generators bear all costs appearing due to their grid connection. In the case of wind turbines or small-scale CHP plants with an output less than 15 MW, they are usually connected at the 20 kV up to 30 kV distribution level. In Austria these generators are equipped with a transformer station from generation level to a 20kV / 30 kV level and afterwards are directly connected to the closest 110 kV substation. The generators are obliged to cover the costs of these direct lines. This amounts to about five to seven percent of the total investment costs, which is in comparison to a large-scale thermal power plant a very high percentage.
Moreover, owners of power plants have to pay for all investments in their grid connection in higher voltage levels as well. In order to avoid bottlenecks in the transmission grid, the grid has to be reinforced by the Transmission System Operator but again the costs are covered by the responsible power plant. In the case of renewable generators, different approaches exist on how to share these investments in the transmission grid. While in the federal state Burgenland the costs are calculated for each renewable generator, in Lower Austria a standardized contribution fee for wind turbines is calculated (CONSENTEC, 2003).

Generally, the costs of System Operators for operating and maintaining their grids are paid by the end-consumers of electricity. Generators pay only a grid contribution fee once they are grid connected and a system tariff per generated kWh electricity in order to cover the costs due to load variations. On the other hand, end-consumers pay a grid allocation fee at the moment of grid connection and an annually measuring fee. Furthermore, a grid loss tariff as well as a grid utilization tariff per used kWh electricity is paid by them, depending on the grid level and the federal state where they are connected. An overview of these tariffs is given in chapter 6.3.2.

7. Economics of onshore wind power and small-scale CHP plants in Austria

This chapter presents the economics of wind power and small-scale CHP plants in Austria and all the related costs caused by them. These renewable generation sources are strongly supported in Austria and therefore they increasingly influence the Austrian electricity system, as is discussed in the previous chapter.
Within this chapter, the first part offers case studies on economics of wind power in Austria. Furthermore, it is incurred on additional costs caused by wind power as the higher balancing prices and the incomes of the sold electricity are explained as well.
In a further subchapter, the economics of small-scale CHP plants are discussed. The levelized electricity generation costs, depending on the different kinds of fuel, are presented, as well as the incomes of the produced heat and electricity.
Finally, the impact of wind generators and small-scale CHP plants on the local distribution grids are illustrated in the last sub-chapter. The distribution grid tariffs as well as the costs arising for the electricity generators are discussed.

7.1 Case study on economics of wind power

The levelized generation costs of Austrian wind mills are discussed in this subchapter in detail and the influence on the balancing costs for the whole electricity market is described as well. Furthermore, the historical deployment of subsidy schemes is demonstrated.
A case study of a nine MW wind park in Lower Austria compares the arising generation costs to the incomes of the sold electricity.

7.1.1 Generation costs and incomes

Due to the geographic situation in Austria most of the wind mills are erected in the Eastern part of Austria where the landscape is very flat and therefore hardly any obstacles for the wind exist. Furthermore, many wind mills are set up in the shape of a wind park instead of single wind mills spread all over the country. This effect decreases the O&M costs slightly compared to the same amount of single wind mills. On the other hand, wind mills in Austria are only able to achieve full-load hours between 2000 and 2150 hours per year due to the geographic location in the center of Europe. Unfortunately, the advantage of less O&M costs does not compensate the impact of smaller full-load hours on the generation costs completely.

As in the case of wind generation costs of Denmark, the real generation costs are difficult to find in the literature and therefore levelized generation costs are calculated with respect to the corresponding formulas in chapter three.

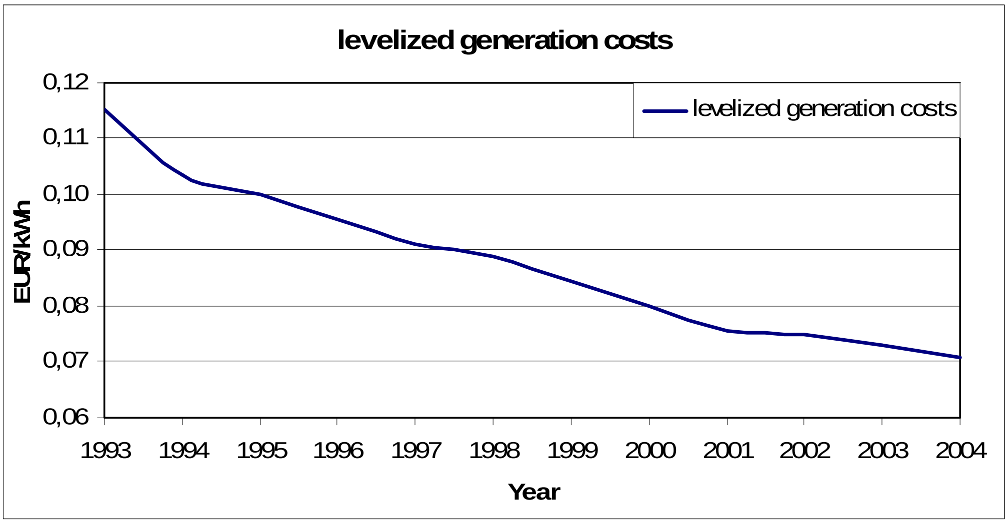

Figure 7.1 Deployment of the levelized wind generation costs in Austria; Source: (Resch, G.; 2007)

Figure 7.1 illustrates the historical deployment of the levelized electricity generation costs of wind mills. These generation costs take a discount rate of 6,5 percent and an amortization period of 15 years into account, like they are usually calculated in Austria. As can be seen in figure 7.1, the present generation costs are still higher than the actual electricity price and therefore wind energy is still depending on subsidies from public institutions.
Furthermore, it is to mention that it is not possible to calculate an own experience curve for wind generation costs in Austria, due to the fact that learning is a global effect and in the case of wind energy dominated by Denmark. Nevertheless, wind electricity generation costs in Austria decreased enormously.

In order to provide lucrative contracts for investors in wind mill projects, the levelized electricity generation costs are calculated with an amortization period of 15 years only. This guarantees investors a short pay-back time even in cases when the expected full-load hours cannot be achieved due to less wind speeds and is therefore seen as risk premium. On the other hand, this risk premium has to be a good compromise between a competitive situation for the wind mill owner and incentives for the investors. Figure 7.2 compares the levelized generation costs at an amortization period of 15 years as it is more favorable for investors than the generation costs at a period of 20 years, which is more economically feasible for the wind park owners. This risk premium results in almost ten percent higher generation costs, but since this risk premium is taken into account at most wind mills, it is still a fair and legal method (Resch, G.; 2007).

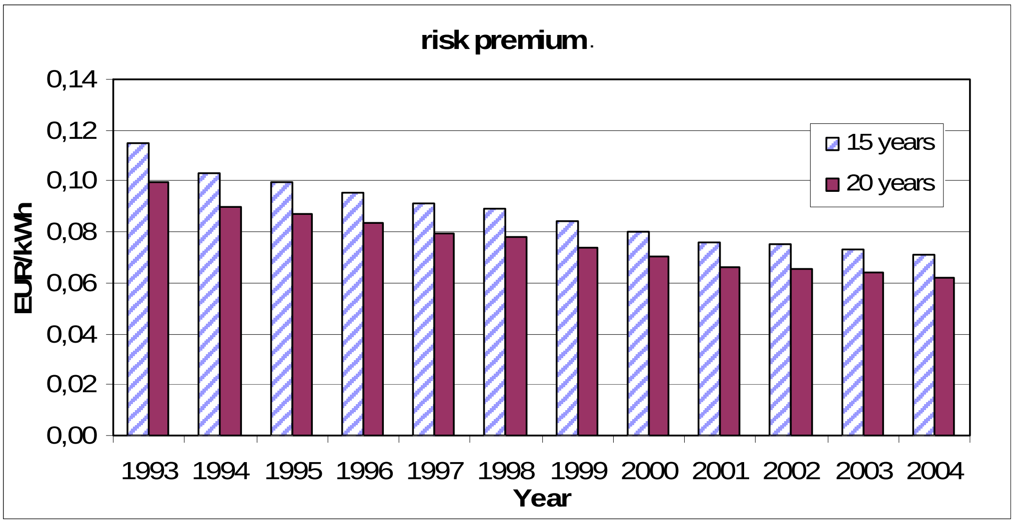

Figure 7.2 Additional risk premium due to a shorter amortization period; Source: (Resch, G.; 2007)

Since the penetration of wind energy on the Austrian electricity market increased, also an impact on the balancing price is observed. Wind speeds are very difficult to forecast although a lot of efforts have been made in the past years. As it is mentioned in the previous chapter, in the Austrian electricity system it is required to forecast the energy production 24 hours in advance and in cases of weekends and holidays the expected energy production has to be notified for the whole time on the last working day before. This organization causes a forecast error of 45 percent and therefore leads to a high deviation of electricity generation from the planned generation. In this way, the total costs for balancing the whole electricity market increase notably.

Furthermore, it is to distinguish between the costs of balancing power and the clearing price. The clearing price represents the costs the different balancing groups have to pay for the regulation of the total market and therefore includes the balancing power costs and administrative costs. An overview of the deployment of the balancing power costs only, is presented in figure 7.3 below (Obersteiner, C.; 2007).

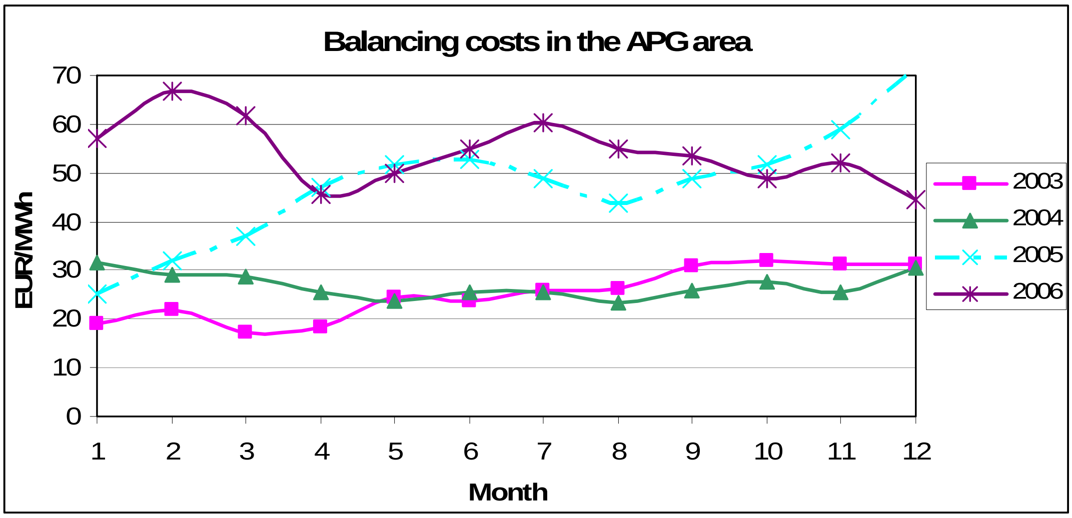

Figure 7.3 Balancing power costs in the APG are since 2003; Source (APCS)

Because wind energy generation costs are still above the electricity price in Austria different subsidy schemes got developed in the past. The Austrian Act on Electricity Supply (ELWOG) regulates the amount and duration of subsidies and furthermore is adapted every few years.

The present legislation addressing green energy within the ELWOG is called "Ökostromgesetz" and was issued at June 26th, 2006. The energy supply companies are obliged by law, according to paragraph §10, to take over the generated wind energy for a certain period of time. This directive is presented in table 7.1 below.

Table 7.1 Wind subsidy schemes sorted by date of approval according to the Ökostromgesetz 2006, paragraph §10; Source: E-Control Austria

Approved before December 31st, 2002	Each federal state was free to determine their own feed-in tariffs. Some paid different subsidies in summer and winter and others only distinguished between new and old wind mills. These feed-in tariffs varied in between 4,56c€/kWh and 12,02c€/kWh.
Approved between January 1st, 2003 and December 31st, 2004.	Standardized feed-in tariffs in all of Austria got introduced and it was set at 7,8 c€/kWh for the first 13 years of operation. Furthermore, from the 14th to the 25th year the energy suppliers were obliged to take over all the generated electricity from the wind mills to the market price minus the balancing costs.
Approved between January 1st, 2005 and December 31st, 2011	A feed-in tariff of 7,65 c€/kWh in 2006 and 7,55 c€/kWh in 2007 is determined in all of Austria for ten years only. In the 11th year, energy suppliers are forced to buy the wind energy for 75 percent and in the 12th year for 50 percent of the feed-in tariff. Until the 24th year energy suppliers are obliged to buy all the generated wind energy to market conditions minus the balancing costs.

As is explained in table 7.1, the Austrian subsidy scheme for wind energy was determined by the nine different federal states. Thus, these feed-in tariffs varied wildly, most wind mills were erected in the areas with the highest feed-in tariff and not in the places where it would be most efficient. This disadvantage was compensated in January 2003 by introducing one feed-in tariff for all of Austria. The range of former feed-in tariffs and deployment of the present tariff is presented in figure 7.4 below (E-Control, 2007).

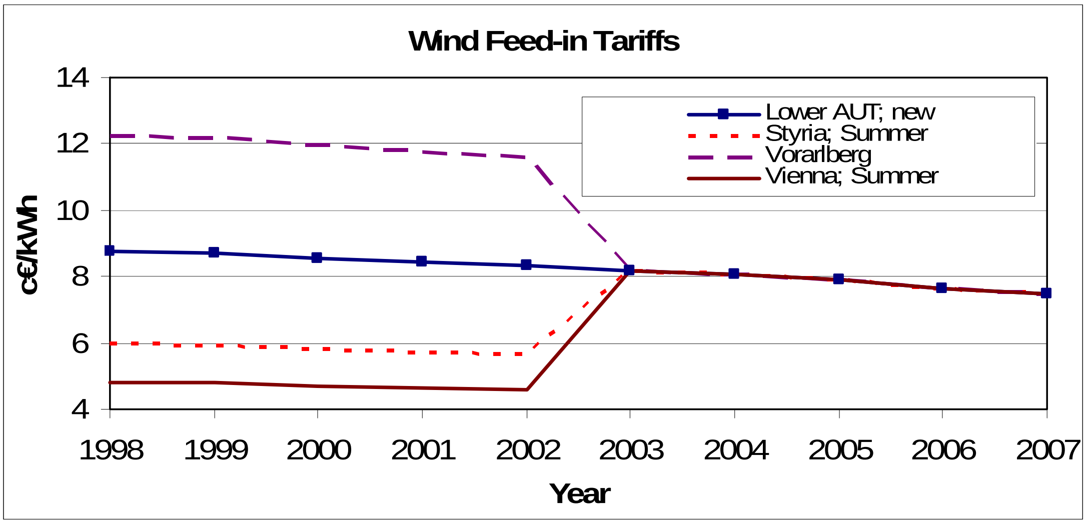

Figure 7.4 Deployment of feed-in tariffs for wind energy, prices in Euro 2006; Source (E-Control, 2007)

The major difference between the feed-in tariff presented in figure 7.4 and the actual electricity spot market price is paid by end-consumers by an additional green surcharge on their electricity bill. Only a small part concerning the balancing costs of renewable energy sources is collected by the distribution grid tariffs of the end-consumers.

7.1.2 Case study on a 9MW wind park in Lower Austria

This sub-chapter points out the economics of a specific wind park in Neusiedl/Zaya in Lower Austria. Five wind mills with an electrical power of 1,8 MW each are connected to the 20 kV distribution grid since November 2002. Next to each wind mill a 690 V/20 kV transformer station transforms the electricity to one 20 kV cable which is directly connected to the closest 110 kV substation.

The wind mills are manufactured by ENERCON with a hub height of 86 meters and a rotor diameter of 70 meters. Since these wind mills are in operation, a certain annual amount of electricity is produced. In the following case study, this constant electricity production is postulated. Moreover, the calculations are based on an annual inflation of 1,7 percent and all prices are in Euro 2006. This case study takes into account a discount rate of 6,5 percent and an amortization period of fifteen years. Furthermore, every wind park owner in Lower Austria was obliged to pay 100 Euro per installed kilowatt to the distribution system operator for investments in the higher voltage grids and substations. This payment is also regarded in the case study below[18].

[18] Interview with Mr. Zischkin at the EVN-Naturpower in Lower Austria - responsible for the designing of wind parks.

Table 7.2 Case study on a nine MW wind park in Lower Austria

Year	Installation costs	O&M costs	deflator	Installation costs	O&M costs	prdouced electricity	feed-in tariff	annual income	annual expense	accumulated income	accumulated expense
	EUR	EUR	%	EUR 2006	EUR 2006	kWh	EUR06/kWh	EUR 2006	EUR 2006	EUR 2006	EUR 2006
2002	1.064.629	348.816	1,065	1.133.830	371.489	3.500.000	0,0831	290.745	1.505.318	290.745	1.505.318
2003	1.064.629	348.816	1,051	1.118.925	366.605	21.000.000	0,0820	1.721.538	1.485.530	2.012.283	2.990.849
2004	1.064.629	348.816	1,031	1.097.632	359.629	20.000.000	0,0804	1.608.360	1.457.261	3.620.643	4.448.110
2005	1.064.629	348.816	1,014	1.079.534	353.699	19.500.000	0,0791	1.542.294	1.433.233	5.162.937	5.881.343
2006	1.064.629	348.816	1,000	1.064.629	348.816	18.700.000	0,0780	1.458.600	1.413.445	6.621.537	7.294.787
2007	1.064.629	348.816	0,988	1.051.853	344.630	19.200.000	0,0771	1.479.629	1.396.483	8.101.166	8.691.270
2008	1.064.629	348.816	0,976	1.039.078	340.444	19.200.000	0,0761	1.461.658	1.379.522	9.562.823	10.070.792
2009	1.064.629	348.816	0,964	1.026.609	336.359	19.200.000	0,0752	1.444.118	1.362.968	11.006.941	11.433.760
2010	1.064.629	348.816	0,953	1.014.289	332.322	19.200.000	0,0743	1.426.788	1.346.612	12.433.729	12.780.372
2011	1.064.629	348.816	0,941	1.002.118	328.335	19.200.000	0,0734	1.409.667	1.330.453	13.843.396	14.110.824
2012	1.064.629	348.816	0,930	990.093	324.395	19.200.000	0,0725	1.392.751	1.314.487	15.236.147	15.425.311
2013	1.064.629	348.816	0,919	978.211	320.502	19.200.000	0,0717	1.376.038	1.298.713	16.612.185	16.724.025
2014	1.064.629	348.816	0,908	966.473	316.656	19.200.000	0,0708	1.359.525	1.283.129	17.971.710	18.007.154
2015	1.064.629	348.816	0,897	954.875	312.856	19.200.000	0,0700	1.343.211	1.267.731	19.314.921	19.274.885
2016	1.064.629	348.816	0,886	943.417	309.102	19.200.000	0,0427	819.054	1.252.518	20.133.976	20.527.403
2017		348.816	0,876		305.392	19.200.000	0,0421	809.226	305.392	20.943.201	20.832.796
2018		348.816	0,865		301.728	19.200.000	0,0416	799.515	301.728	21.742.716	21.134.523
2019		348.816	0,855		298.107	19.200.000	0,0411	789.921	298.107	22.532.637	21.432.631
2020		348.816	0,844		294.530	19.200.000	0,0406	780.442	294.530	23.313.079	21.727.160
2021		348.816	0,834		290.995	19.200.000	0,0402	771.076	290.995	24.084.155	22.018.156
2022		348.816	0,824		287.503	19.200.000	0,0397	761.823	287.503	24.845.979	22.305.659
2023		348.816	0,814		284.053	19.200.000	0,0392	752.682	284.053	25.598.660	22.589.713
2024		348.816	0,805		280.645	19.200.000	0,0387	743.649	280.645	26.342.310	22.870.357
2025		348.816	0,795		277.277	19.200.000	0,0383	734.726	277.277	27.077.035	23.147.634
2026		348.816	0,785		273.950	19.200.000	0,0378	725.909	273.950	27.802.944	23.421.584

The example shows the interaction between the expenses caused by a wind park and the allowed incomes according to table 7.1. The feed-in tariff is paid for the first 13 years and afterwards the market price will be received according to the tariffs of E-control. In figure 7.5 below, the economics of this wind park are visualized.

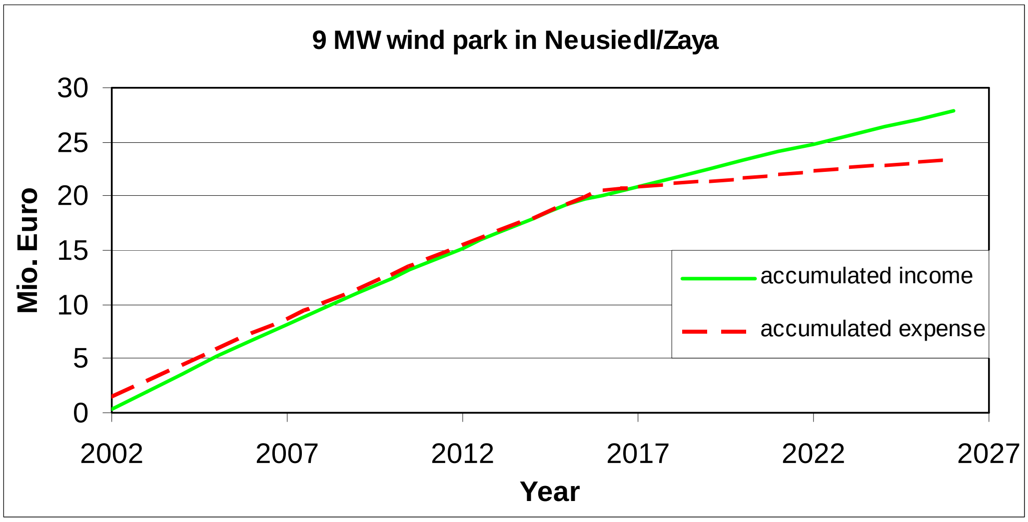

Figure 7.5 Economics of a 9 MW wind park in Lower Austria; Prices in Euro 2006

In figure 7.5 is illustrated that the wind park Neusiedl/Zaya is operated almost cost-covering within the first 15 years in case of an at least constant electricity output. After fifteen years in operation, the amortization period of the investment costs will be finished and the wind park owner has only to cover the annual O&M costs. Then the incomes will decrease as well because this wind park will not be eligible for any subsidies anymore. Nevertheless, the total profit will increase at that time due to little O&M costs and a may be higher electricity spot market price.

7.2 Case study on economics of small-scale CHP plant

This subchapter addresses the economics of Austrian small-scale CHP plants. Therefore, the presented calculations of the levelized generation costs distinguish between different kinds of fuels. Moreover, the historical development of the subsidy schemes is explained as well as.

In the second subchapter a case study demonstrates the economics of a small-scale CHP plant with a five Megawatt electrical power, fired by wood-chips.

7.2.1 Generation costs and incomes

This subchapter presents the economics of small-scale Biomass and waste incineration CHP plants, thus no data were available for natural gas fired CHP plants. This is a result of a historically strong subsidy scheme in different Austrian federal states for Biomass CHP plants. Therefore, most Biomass CHP plants are operated in Tyrol and Lower Austria but since the subsidy scheme got standardized in 2003 most new CHP plants are erected close to the fuel source.

The annual expenses are mainly influenced by the O&M costs and the different fuel costs. As the O&M costs of Austrian biomass plants are almost independent of the kind of fuel, the fuel costs vary widely. Figure 7.6 demonstrates an overview of biomass fuel costs in Austria.

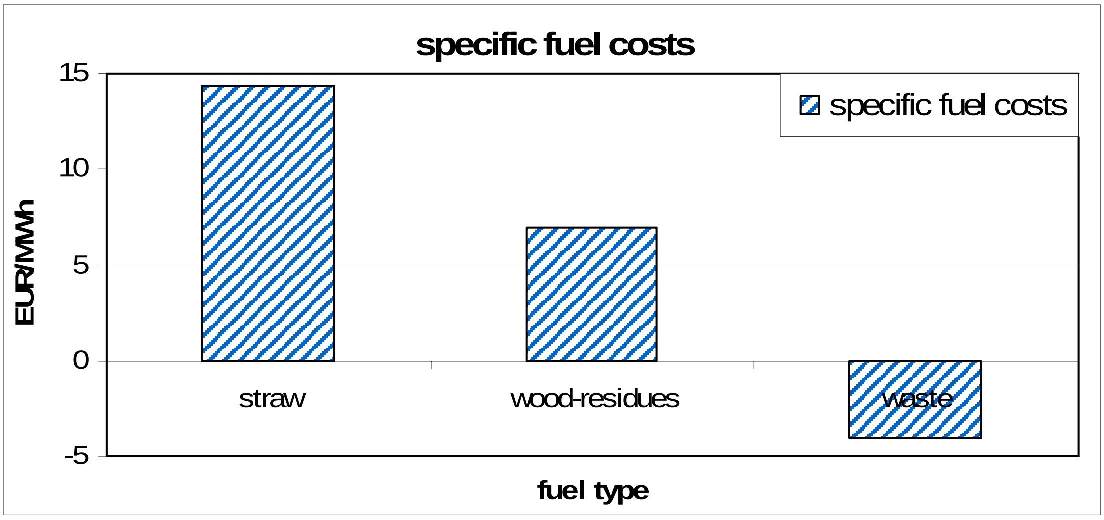

Figure 7.6 Biomass fuel costs in Austria; Prices in Euro 2006 Source: (Haas, R.; et al.;2004)

In figure 7.6 it is shown that the price of straw is more than the double price of local wood-residues. It has to be mentioned that the price of wood-chips is in the range of straw and in a few exceptions even more. Furthermore, the presented costs are depending very much on the distance between the source of the biomass and the location of the small-scale CHP plant. Waste incineration CHP plants receive a certain amount of money whereas the 4,04 Euro/kWh, shown in figure 7.6, are an average between waste from private institutions and industry waste[19].

In order to calculate the levelized generation costs, the revenues of the heat market have to be taken into account as well. An Austrian small-scale CHP plant receives about 40 EUR/MWh heat from the local District heating companies. This revenue, a discount rate of 6,5 percent and an amortization period of fifteen years is considered in the calculation-formulas of chapter four. Due to relatively high investment costs, the impact of full-load hours on the levelized generation costs is very sensitive. This influence is shown in figure 7.7 below.

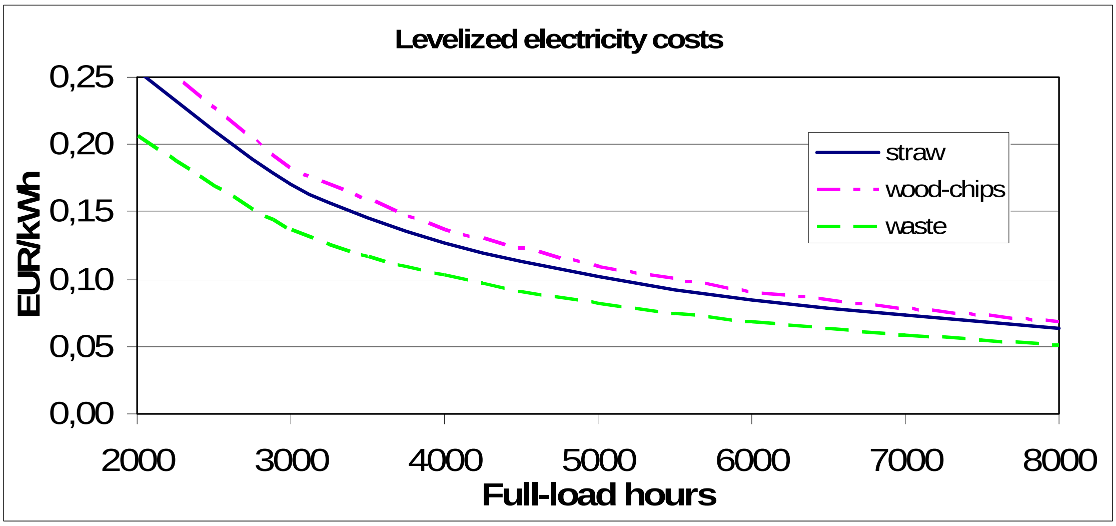

Figure 7.7 Levelized electricity generation costs of small-scale CHP plants depending on the different kinds of fuel; Prices in Euro 2006

Figure 7.7 illustrates the economics of small-scale CHP plants distinguished by the kind of fuel. Since waste incineration plants have only a bit higher investment costs than biomass plants but no fuel costs, their generation costs are the smallest. In order to compare wood-chips to straw technologies, it has to be distinguished if only wood-chips are used in the CHP plant, or forestry residues as well. Forestry residues drop the price of biomass fuel because it has a smaller calorific value.
Furthermore, figure 7.7 points out that small-scale CHP plants are only competitive on the electricity market if they are eligible for generation subsidies. Nevertheless, a certain amount of full-load hours has to be achieved in order to operate the plant feasibly. As is explained below, the feed-in tariffs of Biomass plants varied wildly in the last decade, but at subsidy levels of nowadays small-scale CHP plants are asked

[19]Interview with Mr. Bonleitner at EVN-Naturkraft in Lower Austria, responsible for designing small-scale CHP plants

to generate about 4500 electrical full-load hours. Usually, the heat full-load hours are less because of less heat demand over the year (Resch, G.; 2007).

The Austrian Act on Electricity Supply (ELWOG) regulates the amount and duration of subsidies and is adapted every few years.
The present legislation addressing green electricity within the ELWOG is called "Ökostromgesetz" and was issued at June 26th, 2006. The energy supply companies are obliged by law according to paragraph §11 to take over the energy for a certain period of time. This directive is presented in table 7.3 below.

Table 7.3 Biomass subsidy schemes sorted by date of approval according to the Ökostromgesetz 2006, paragraph 10; Source: (E-Control 2007)

<table>
<tr><td>Approved before December 31st, 2002</td><td>Feed-in tariffs were paid to biomass and waste incineration plants, depending on the federal state. Each federal state paid different tariffs, whereas some distinguished between the kind of biomass, the electrically nominal power, time of erecting and / or the season of the year. These feed-in tariffs varied in a wide range.</td></tr>
<tr><td>Approved between January 1st, 2003 and December 31st, 2004</td><td>Within these two years a standardized feed-in tariff was paid in all of Austria for 13 years after coming to operation. From the 14th year until the 25th year power supply companies were obliged to take their electricity over, but only the market price was paid to the generators.
The feed-in tariffs in that time amounted to:
<table>
<tr><td>Until 2 MW plants</td><td>16 c€/kWh</td></tr>
<tr><td>2 MW until 5 MW plants</td><td>15 c€/kWh</td></tr>
<tr><td>5 MW until 10 MW plants</td><td>13 c€/kWh</td></tr>
<tr><td>More than 10 MW plants</td><td>10,2 c€/kWh</td></tr>
<tr><td>Waste incineration plants</td><td>20-35 percent less than a similar biomass CHP plant</td></tr>
<tr><td rowspan="2">Multi-fuel CHP plants</td><td>Biomass and natural gas
6,5 c€/kWh</td></tr>
<tr><td>Waste and natural gas
5 c€/kWh</td></tr>
</table></td></tr>
<tr><td>Approved after January 1st, 2005</td><td>A standardized feed-in tariff is paid in all of Austria for ten years only. In the 11th year, generators are eligible for 75 percent of the tariff and in the 12th year for 50 percent. Afterwards, the market price is paid to them until the 24th year of operation, when the power supply companies are obliged to take over their produced energy.</td></tr>
</table>

The following feed-in tariffs are paid nowadays:

Until 2 MW plants	15,7 c€/kWh
2 MW until 5 MW plants	15 c€/kWh
5 MW until 10 MW plants	13,4 c€/kWh
More than 10 MW plants	11,3 c€/kWh
Waste incineration plants	25-40 percent less than a similar biomass CHP plant
Multi-fuel CHP plants	6,4 c€/kWh

Table 7.3 and figure 7.8 below illustrate the disadvantages of the previous subsidy scheme, because biomass CHP plants were only erected in the economically most feasible federal state instead of at the shortest distance to the fuel source or the greatest heat demand (E-Control, 2007).

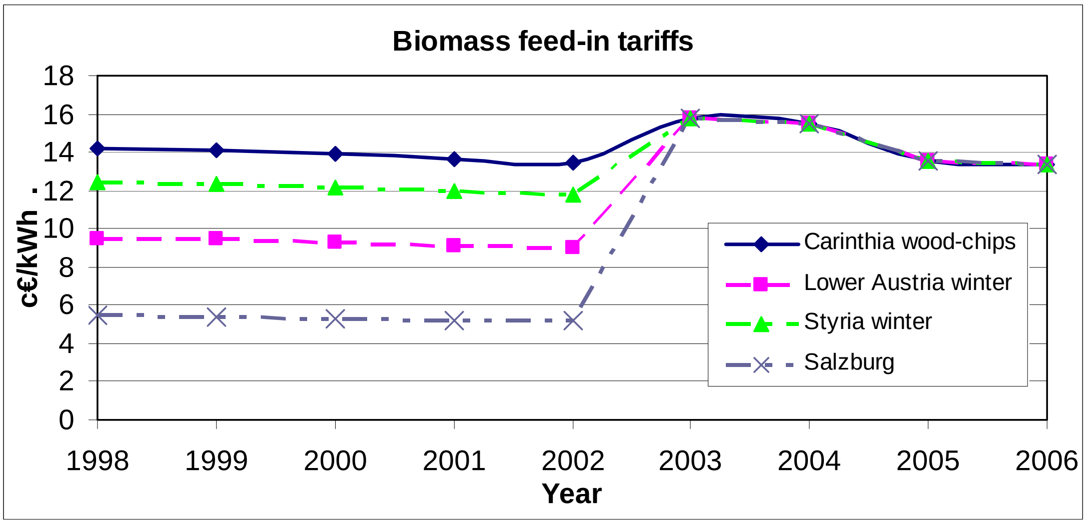

Figure 7.8 Deployment of subsidies of biomass CHP plant at an electrical power output between 5 MW and 10 MW; Prices in Euro 2006; Source: (E-Control, 2007)

In addition to the biomass tariffs, small-scale CHP plants are eligible for CHP subsidies as long as they do not exceed a certain amount of subsidies due to the feed-in tariffs. The maximum subsidy is calculated as the electricity generated in the first twelve months of operation times the difference between the feed-in tariff and the market price at 6000 full-load hours. This heat subsidy depends on the electrical tariff and the heat value on the market and is calculated with respect to the following formula:

$$h_{tariff} = \frac{e_{tariff}}{4,4} - h_{price}.$$

h_{tariff} heat subsidy
e_{tariff} electrical feed-in tariff
h_{price} determined heat market price

Here, it is to mention that the heat price is set on 2,6 c€/kWh at CHP plants with an electrical output up to 10 MW and on 1,8 c€/kWh at CHP plants of more than 10 MW.

Finally, according to the "Ökostromgesetz" §12 small-scale, biomass CHP plants are eligible for investment grants up to ten percent if they are approved of until September 30th, 2012 and in operation before December 31st, 2014.

7.2.2 Case study on a five MW biomass CHP plant in Lower Austria

This subchapter points out the economics on a specific small-scale CHP plant in Baden[20]. The generator has a nominal power of five Megawatt electrically and twelve thermal Megawatts. It produces 32 GWh electricity every year and 38 GWh heat are sold to the District Heat system in Baden. Thus, in summer the heat demand is less which implies 6500 electrical full-load hours and 3180 heat full-load hours. Therefore, a total efficiency of 91 percent is achieved. This small-scale CHP plant is fired by a mixture of wood-chips and forestry residues from local sources with 200.000 m³ every year[21].

Table 7.4 Case study on a five MW small-scale biomass CHP plant in Lower Austria

Biomass CHP plant - Baden						
Year of construction:	2006					
Electric power	5 MW	Fuel types			fuel energy	3,8 kWh/kg
Thermal power	12 MW	wood chips	share	100 %		
Annual electricity prod	32,5 GWh		input	76.371 t/a	full-load hours ele	6500 h
Annual heat production	38,2 GWh			11,749 t/h	full-load hours heat	3180 h
				290.210 MWh/a		
Total efficiency	91 %		costs	13,800 EUR/MWh		
Investments costs	4.000.000 EUR/kW					
	20.000.000 EUR					
fuel costs	4.004.895 EUR/a					
annual O&M costs	122,02 EUR/kW					
	610.081 EUR					
Income		for 10 years, in the 11th year only 75%, the 12th year 50% and afterwards market				
Electricity	0,134 EUR/kWh	price of 0,0481EUR/kWh				
heat	38,52 EUR/MWh					
CHP subsidy	4,4545 EUR/MWh	only until 2008				

In order to visualize the interaction between the expenses and the incomes of electricity and heat, this calculation takes into account the tariffs according to table 7.2. Furthermore, a mixture between the fuel prices of wood-chips and forestry residues is considered and an annual inflation of 1,7 percent is regarded as well. When the CHP plant was only been in operation, since one year the annual energy generation is based on the output of 2006 and set as constant for the future. Figure 7.9 below illustrates the comparison of expenses and incomes of the biomass CHP in Baden.

[20] A similar biomass CHP plant is erected in Mödling, a neighboring town of Baden which is operated from the same power supply company and therefore the developing costs are split between both CHP plants

[21] Wood-chips and forestry residues are provided by local farmers in a distance of 100 km around the CHP plant

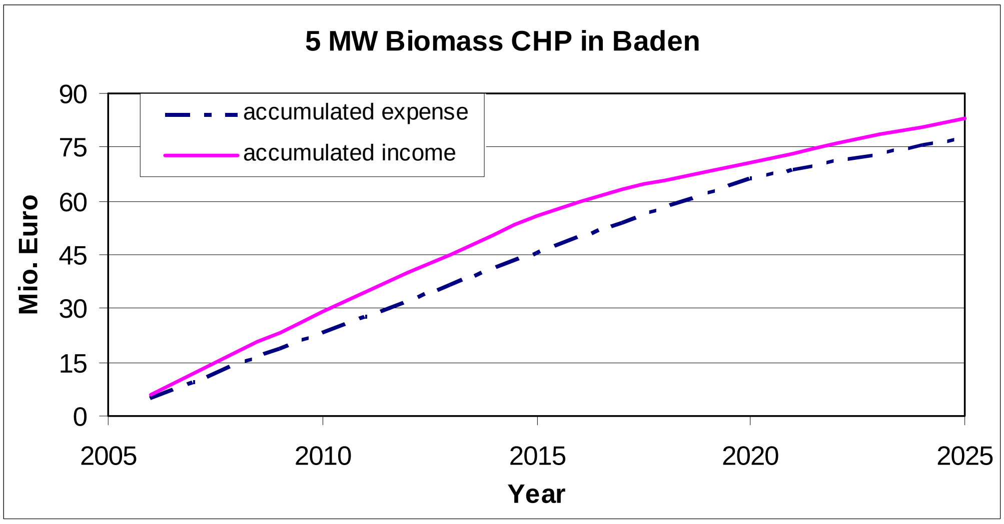

Figure 7.9 Economics of the small-scale CHP plant in Baden; Prices in Euro 2006; Source: EVN-Naturkraft

7.3 Impact on the grid development and related costs

The impact of wind energy and small-scale CHP plants on the Austrian distribution and transmission grids increased within the last decade. Every new power generator requires an extension of the distribution grid, and sometimes reinforcements in the transmission lines are necessary as well. This enlargement and the related costs are discussed in the following two subchapters. The first chapter addresses the costs borne by the generators themselves and the second subchapter explains the socialized costs paid by the customers.

7.3.1 The impact and costs from the generator's point of view

As is mentioned in chapter 5.1, Austria implemented a Deep Costs Approach and therefore new electricity generators have to bear all arising costs of their grid connection. Moreover, a contribution to the local system operator has to be paid in order to cover his costs for reinforcing or extending the high voltage grid. Once the connection lines to the closest substations are built and paid by the generators, the lines are operated by the local Distribution System Operators who are also responsible for safety and reliable operation. The costs of operation and maintenance of these connection lines, are shared among the electricity consumers.

Thus, most Austrian wind parks are installed in the East part of Austria. All wind parks in that area are connected to the 20 kV or 30 kV level directly to the closest 110 kV sub-station. Therefore several 110 kV sub-stations had to be reinforced and a few sub-stations were newly erected. This system might not be the most efficient but results in the smallest grid investment costs for each wind park owner.

Due to the single connection lines to the substations, the impact on the 20 kV distribution grid of EVN-Netz, the Distribution System Operator in Lower Austria, is very sensitive. Figure 7.10 illustrates the relation between wind turbines and the 20kV grid enlargement[22].

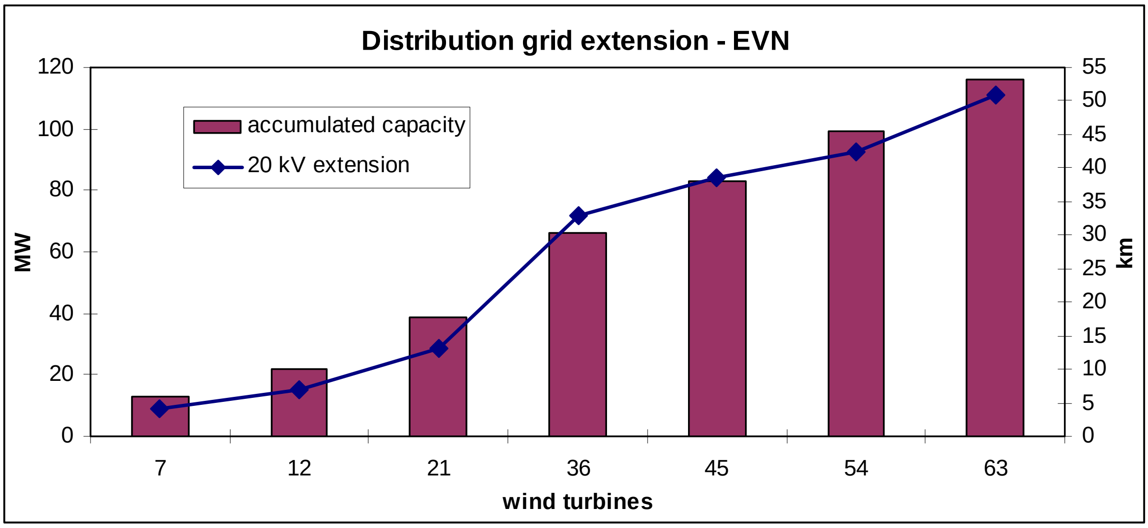

Figure 7.10 Installed wind capacity within the regarded EVN area at the left scale and caused 20 kV grid extension on the right scale; Source (Eckmayer, H., 2007)

Figure 7.10 shows a constant growth of the distribution grid with an increasing penetration of wind energy and no benefits of planning ahead are noticed. This is the result of direct connection lines between the wind mills and the 110 kV substations. The same results arise in researches at the BEWAG-Netz company, the Distribution System Operator of Burgenland. In their area 138 wind mills were considered, with a total power of 242 MW and a constant enlargement up to 200 km is detected. Depending on the power output of the wind parks in Burgenland, some parks are connected via 20 kV lines using a 240 mm² aluminum cable and the rest via 30 kV lines using a 500 mm² copper cable. In Lower Austria all considered wind parks are connected at the 20 kV level using 240 mm² aluminum cables in single or double laying designing.

The derived grid connection costs for wind mill owners are almost the same in these two regions, whereas the dominant parameter is the connection distance. This distance amounts in average five kilometers, but in Burgenland there are a few wind parks up to 20 kilometers away form the 110 kV sub-station. Therefore, the specific grid costs in Burgenland, including cable and digging the trench, are lower because the trenches on the countryside are ploughed by a tractor (Stoirer, K.; 2007).

[22] Only wind turbines of the EVN-Naturkraft company are regarded within this thesis, because no information of private wind generators was available.

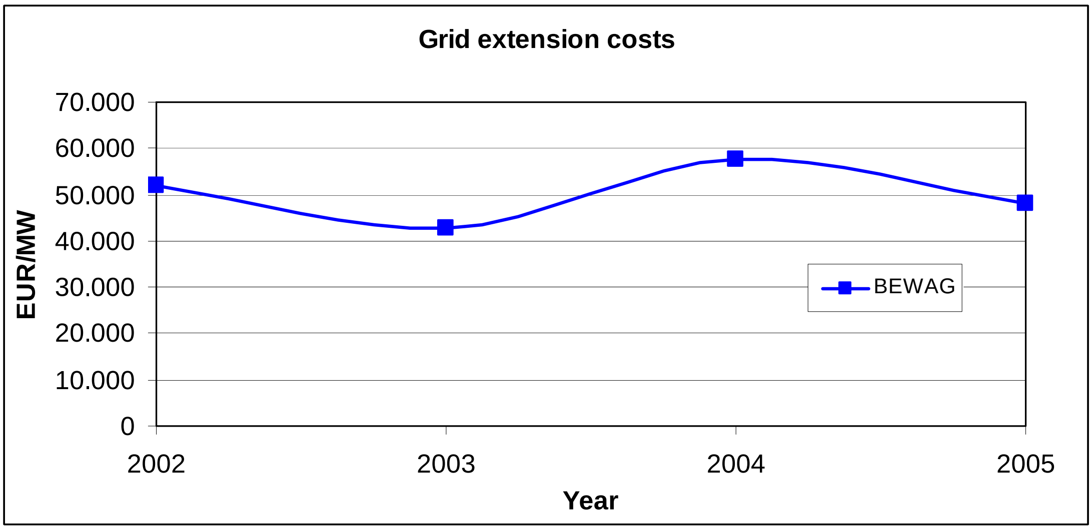

Figure 7.11 Specific 20 kV grid extension costs in the BEWAG area due to 242 MW installed wind power; Prices in Euro 2006; Source (Stoirer, K.; 2007)

Figure 7.11 demonstrates the specific investment costs. In figure 7.11 no experience rate is visible because the costs are mainly determined by the distance of connection and the influence of cable type is hardly recognized.

The influence of small-scale CHP plants on the distribution grid is not detectable, mainly because no association exists between who owns the plants and who operates the grid. Hence, most of the small-scale CHP plants are operated by private institutions and therefore no data was available. Nevertheless, CHP plant owners have to bear their connection costs themselves, like wind turbine owners, at almost similar specific investment costs.

In order to feed the wind energy into the transmission grid the 110 kV substations in Pama and Neusiedl had to be reinforced, which means to add high voltage segments and replace cables. Furthermore, the 110 kV substation with a nominal power of 80 MVA was erected in Parndorf only to handle the newly installed wind energy. In Lower Austria, most wind parks are connected to the sub-station Bisamberg in the North and Bruck an der Leitha in the South. Bisamberg was reinforced as well, whereas Bruck an der Leitha was built anew. In order to reinforce a 110 kV substation, costs of almost two million Euros have to be taken into account, depending on the concrete work whereas a new 80 MVA substation allocates more than three million Euros.

This thesis takes into account the wind energy generation in Lower Austria and Burgenland. Since the Deep Cost Approach is a national legislation, there are some different directives of the federal governments. Hence, the contribution tariff in order to cover the costs of reinforcing higher voltage levels varies in between the federal states.

In Lower Austria all costs that arose due to new wind mill installation are shared among all wind mill owners proportionally. Therefore, the DSO, EVN-Netz, estimated the total investment costs in the high voltage grids, due to reinforcing and extending the grid and setting up new 110 kV substations. Based on this result the expected, specific costs per installed kW wind energy are calculated. In case of a deviation from the expected results, EVN-Netz was poised to either refund or ask for more money *ex post*, depending on the real costs. Table 7.5 presents an overview of the calculations of EVN-Netz for a 350 MW wind power extension in Lower Austria (CONSENTEC, 2003).

Table 7.5 Contribution tariff of new installed wind energy in Lower Austria; Source: (CONSENTEC, 2003)

EVN	km	number	specific costs		total costs	
110 kV cable	119		226.050	EUR/km	26.900.000	EUR
new 110 kV substation		6	2.200.000	EUR/nr	13.200.000	EUR
reinforcement of 110 kV substation		4	2.850.000	EUR/nr	11.400.000	EUR
total investement					51.500.000	EUR
total investement due to 350 MW wind power			102.514	EUR/MW	35.880.000	EUR

According to the calculations of EVN-Netz in table 7.5, the upgrading of the grids allocated 51,5 million Euro whereas only 35,88 million Euro were caused by newly installed wind energy. Therefore, every wind turbine owner in Lower Austria had to pay a contribution fee of 100 EUR/kW when it got grid connected.

In Burgenland the DSO, BEWAG-Netz shared the investment costs for upgrading its grid among the wind turbine owners separately. In this way, each wind mill owner had to pay a contribution fee according to the costs he caused in the high voltage grids. Therefore, the average contribution fee was less than in Lower Austria and ranged between 38 EUR/kW and 62 EUR/kW. On the one hand, this pricing system is fairer than in Lower Austria but on the other hand, the 110 kV grid in Burgenland was more strongly built and therefore the contribution fee was lower.

7.3.2 The socializing method of grid related costs

The resulting costs of grid investments are socialized in two parts. Firstly, energy generators have to pay a contribution fee. On the other hand, grid operating costs and maintenance costs are socialized among the energy consumers.

Concerning these grid tariffs, it has to be distinguished between the energy consumption of the consumers and the consequential voltage level where the consumers are connected. The Austrian transmission and distribution grid is divided into seven levels, whereof the first is the highest voltage at 380 kV and the seventh level is the distribution level at 0,4 kV. The tariffs are increasing with each voltage level, meaning the highest tariff is charged on the seventh level. Furthermore, the tariffs vary between the nine federal states. An explanation is given in table 7.6 below[23].

Table 7.6 Description of the grid tariffs paid by the energy consumers; Source: Regulation SNT-VO 06

Grid-allocation tariff	The consumers pay a certain amount per kilowatt once they get grid connected, depending on the grid level and the federal state in order to cover the costs of the System Operators due to the physical connection work. No grid-allocation tariff exists on grid level 1 and 2.
Grid-utilization tariff	This tariff satisfies the costs of the System Operators for operating and maintaining the grid in a stable and reliable state. It depends on the grid level and the federal state, too.
Grid-loss tariff	It is only a small tariff in order to cover the costs of grid losses, again depending on the grid level and the federal state.
Measuring tariff	The measuring tariff is a fixed price per year, depending on the service of each consumers. Such services are measuring the used energy, renting measuring instruments or online measuring.

The composition of the Austrian grid tariff is given in table 7.6. It is to mention that the grid-allocation tariff is only paid once except the installation power will be changed afterwards. Out of the rest, the grid-utilization tariff is the dominant part and amounts to about 90 percent of the total annual grid costs on grid level 7, where all private households are connected.

Figure 7.12 compares the grid-allocation tariff of different grid levels within different federal states. Grid-level 7 has the highest tariffs, thus the energy consumption of each single connection is smallest and the tariffs get smaller the more the energy consumption increases. Furthermore, no relation between the different grid levels in different federal states is observed. Therefore, the grid tariff of level 3 in Carinthia is one of the smallest, whereas in the same federal state the tariff on level 7 is one of the highest.

[23] System Nutzungstariffe Verordnung 2006; SNT-VO 2006

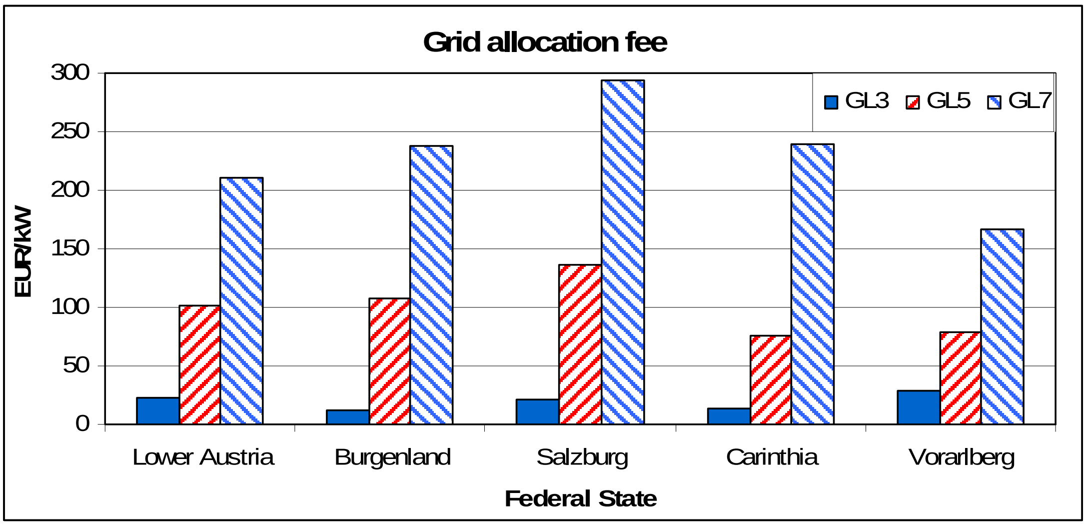

Figure 7.12 Grid allocation tariffs in different federal states at different grid-levels;

Generally, it is to mention that the grid tariffs have to be approved of by the regulatory agency, E-Control, before they are published. An annual reduction of the grid tariffs is arranged by E-Control based on an efficient benchmarking result. This means principally that an inefficient grid has to reduce its grid tariffs by reducing its expenses.

8. Comparison Austria versus Denmark

The comparison of the Austrian and the Danish energy system points out the most important key figures regarding integrated renewable energy, favoring distributed generation.
Therefore, the first subchapter addresses the policies and legislation of renewable energy grants and the different directives in order to grid connect distributed generators. In a further subchapter, the electricity generation costs of wind turbines and small-scale CHP plants are compared. Moreover, this comparison takes the different subsidy schemes into account too.
Another subchapter compares the balancing costs within the two different electricity markets and the impacts of wind energy. Additionally, the impacts of wind turbines and small-scale CHP plants on the grid topologies within Austria and Denmark are compared and the consequential grid costs are taken into consideration as well.
Finally, sensitivity analyzes demonstrate the impact of the above mentioned factors on the economical feasibility of renewable energy in these two countries.

8.1 Directives and policies

It is distinguished between directives concerning the grid connection method and policies supporting renewable energy. Therefore, the first subchapter compares the different subsidy schemes and their development, whereas the second subchapter addresses the grid connection directives.

8.1.1 Policies favoring renewable electricity generation

Since Denmark started to launch directives in order to promote renewable electricity generation already in the year 1973, the Austrian electricity market was still regulated by the Second Nationalization Law from the year 1947. Only in February 1997 the new Austrian electricity law was passed, including the “Ökostromgesetz” addressing renewable electricity generation. Several years before, the ambitious Danish Energy Minister launched the Energy Action plan (Energy 2000) in order to reduce the CO2 emissions dramatically. Although all directives from the European Union were accepted in Austria as well as in Denmark, the Danish national legislation always was stricter than the EU ordered. Moreover, the Danish energy and environmental ministers introduced several national directives in order to promote renewable electricity production from wind turbines and small-scale CHP plants. Therefore, the District Heating grids nowadays are well developed in Denmark and many small-scale CHP plants are able to operate there.
On the other hand, the Austrian electricity generation is dominated by large-scale hydro plants that are not taken into account in all the energy plans but amount to

about 65 percent of the total electricity generation. All new directives and policies address only the non-hydro renewable energy or small-scale hydro plants up to ten Megawatts. Figure 8.1 below illustrates a comparison of renewable electricity generation in Austria and Denmark but excludes the Austrian large-scale hydro plants.

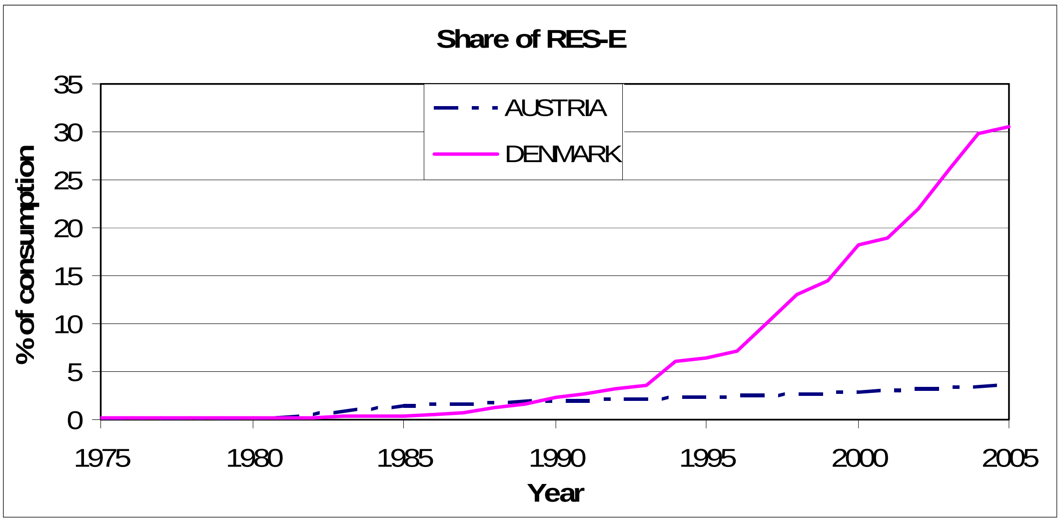

Figure 8.1 Share of renewable energy in percent of electricity consumption, excluding hydro power of Austria; Source: E-Control and Danish Energy Agency

Because renewable electricity generation is neither economically feasible in Austria, nor in Denmark, different subsidy schemes got introduced. In the case of wind energy different parameters influence the development of financial grants.
Both countries have initially chosen feed-in tariffs in order to support their wind electricity generation. Since the penetration of wind electricity in Denmark increased continuously, several modifications of the feed-in tariffs got published so that the total amount of subsidies did not change. As is presented in table 3.1 above, these modifications took place in the year 2000. The guaranteed tariffs were paid for a certain amount of full-load hours depending on the nominal power output. Furthermore, it is distinguished between private wind turbines, household turbines and wind turbines financed by utilities. In the year 2003 new wind generators were not eligible for feed-in tariffs anymore and the system switched to a premium which was modified in the year 2005 again. Due to that change in the subsidy scheme, wind turbines got balancing-responsible too.

On the other hand, the penetration of wind generators in the Austrian electricity system is much smaller. This is caused by the geographical situation of the country and different policies. Most Danish wind turbines are erected along the west shore, in order to generate more full-load hours. Moreover, the mountains in West Austria are big obstacles for the wind. As feed-in tariffs were introduced in Austria, the federal states were allowed to regulate the tariffs by their own. This caused wide spread tariffs as it is presented in table 7.1. The main disadvantage was that wind turbines were erected in the federal state with the highest feed-in tariff than at locations where they would operate more economically. Therefore, wind parks were, for instance, rather installed in Vorarlberg than in Burgenland. This disadvantage was abolished in the year 2003, as a standardized feed-in tariff was published. This tariff was paid for 14 years independently of the production, and until the 25th year of operation it was guaranteed that power suppliers have to take over all the generated electricity. In the year 2005 a new amendment was launched regulating the feed-in tariffs for only ten years, 75 percent of the tariff in the eleventh year and half of it in the twelfth year. This guaranteed feed-in tariff is annually reduced by 0,1 c€/kWh for new wind turbines and amounts 7,55 c€/kWh in the year 2007.

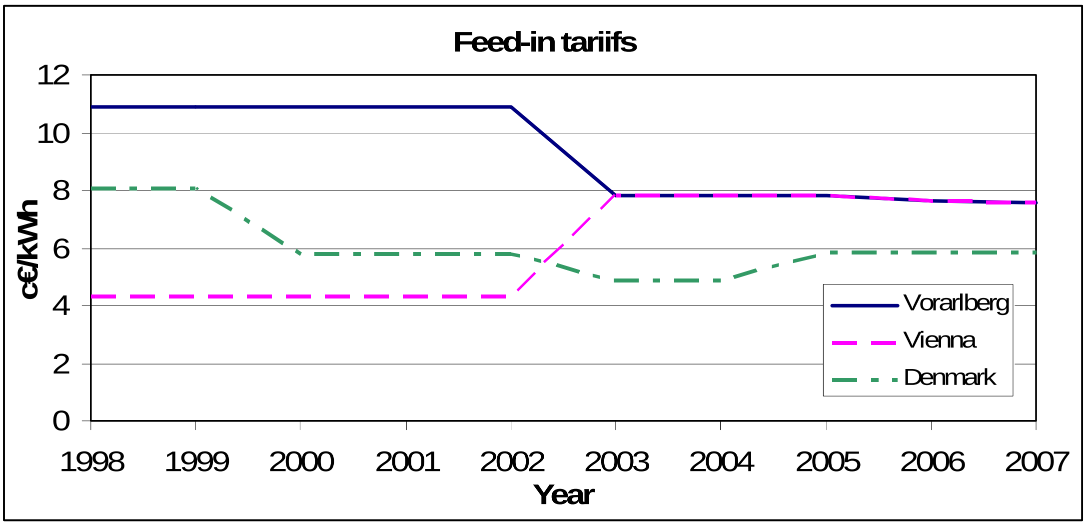

Figure 8.2 Feed-in tariffs for new wind energy converters in Austria and Denmark

Figure 8.2 presents the feed-in tariffs of newly installed wind turbines in Austria and Vienna. It only presents the tariff of the first period, in the case of Denmark a certain full-load hour amount and in Austria the first years. Furthermore, in the period of 2003 and 2004 the presented Danish tariff reflects the maximal tariff; it might be less In case of a higher spot market price because only a premium is paid. Generally, the relative income of Danish wind turbines is smaller but due to the geographical situation they are operated at higher full-load hours.

On the other hand Denmark has comparatively less Biomass and therefore CHP plant owners using Biomass have to buy their fuel from neighbor-countries like Sweden. Since the oil crises in the mid-seventies, Denmark has developed and installed many District Heating Systems which are mostly served with heat by the local small-scale CHP plants. This historical development is caused by the several energy plans aiming at a more efficient utilization of primary energy. In Austria comparatively less small-scale CHP plants are operating, so the District Heating is not as far developed. Nevertheless, several small-scale Biomass CHP plants have

recently been installed. Both countries have initially chosen a feed-in tariff system. Moreover, Austrian biomass CHP plants are additionally eligible for a heat premium if the maximal subsidy amount is not covered by the electricity subsidy. This incentive increased the penetration of small-scale CHP plants in Austria. In the year 2003 Denmark switched from the feed-in model to a premium as for wind turbines. Previously installed small-scale CHP plants are still eligible for the feed-in tariff but newly installed plants only receive a premium.
Other types of Danish CHP plants than Biomass are paid by a three-time tariff or a new model of an individual, non-production related monthly subsidy. In Austria every kind of CHP plant is still paid at the three-time tariff only depending on the nominal power size and kind of fuel, as is presented in table 7.2. An overview give table 8.1.

Table 8.1 Comparison of the different subsidy developments in Austria and Denmark; new systems were introduced in the year 2003

	AUT old	DK old	AUT new	DK new
Wind	Feed-in (federal State)	Feed-in	Feed-in (harmonized)	Premium
Biomass	Feed-in (federal State)	Feed-in	Feed-in (harmonized)	Annual grant
Waste incineration	Feed-in	Three-time-tariff plus fuel grant	Feed-in	Annual grant plus fuel grant
CHP plants	Premium		Premium	

Although the Austrian law distinguishes several different parameters, like the nominal power or the kinds of fuel composition, the feed-in tariffs are almost double than they are in Denmark. Nevertheless, it is very expensive to install a new District Heating System which takes over the produced heat and in Austria no law exists that obliges households to connect to the local District Heating System. Therefore, the penetration of small-scale CHP plants is still very little in Austria.

Generally, it is to mention that the guaranteed feed-in tariffs are not as efficient as the premium subsidy model. The premium model forces generators to invest in more efficient technologies in order to save fuel or increase their outputs. Moreover the premium model is usually connected with a generator balancing responsibility, resulting in more exact schedules and less balancing demand.

8.1.2 Grid connection directives

Basically Austria implemented a Deep Cost Approach whereas Denmark implemented the Shallow Cost Approach.
The Deep Cost Approach requires every power generator to bear all the costs appearing due to the grid connection of his plant. Therefore, every Austrian wind mill small-scale CHP plant owner has to pay for the total connection line until the 110 kV substation where it gets connected. Moreover, the costs for reinforcements or extensions of the existing power grid have to be covered by the power plant owner as well. In the case of wind mills in Lower Austria, a certain fee is calculated and socialized among all new wind mill owners in that area. Other System Operators are calculating the exact costs for each single wind park.
This Approach is very counterproductive for distributed generation because the first new wind mill in an area has to pay the highest cost for the grid connection and reinforcing the existing grid. The following wind mills in the same area are sometimes using these grids. Moreover, the grid extension costs of a few kilometers amount to a considerable high percentage of the total investment costs and are therefore increasing the levelized generation costs.
On the other hand, no grid user has to pay for connection lines of competitors or grid extensions he does not use himself.

This is why, the Danish Shallow Cost Approach is more favorable for distributed generators because every wind turbine owner or small-scale CHP plant does only pay the grid connection costs to the well developed 10 kV node even in case it gets grid connected on a higher voltage line. In case of wind parks one connection point within the park area is defined until which the Distribution System Operator pays the total connection costs and only the price for the single connection lines from each wind mill to the connection point is covered by the owners. The 10kV / 60kV transformer station is also paid by the System Operators. The Distribution System Operators receive refunds of their expenses from the Transmission System Operator according to a model presented in table 4.4 and table 5.7. These refunds are collected by the Transmission System Operator of all grid users through Public Service Obligations (PSO) per consumed kilowatt-hour.

The high percentage of distributed generation in Denmark is mainly caused by the Shallow cost Approach and the small grid connection costs as it is shown in figure 8.3 below.

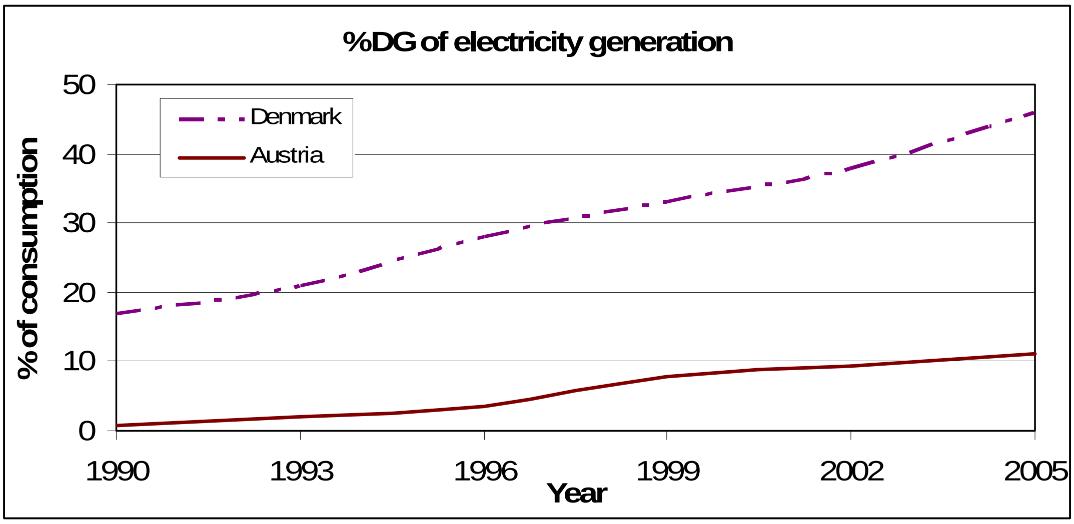

Figure 8.3 Percent of distributed generation of the total electricity generation (Resch, G. 2007)

8.2 Generation costs and Incomes

The first subchapter discusses the levelized generation costs of wind energy in Austria and Denmark and points out the main influences. The second part compares the levelized electricity generation costs of small-scale CHP plants.

8.2.1 Generation costs of wind electricity

In general, the investment costs in Austria and Denmark are within a certain range because there are only a few wind turbine manufactures who are defining the price. Therefore, the difference of levelized generation costs is caused by other parameters which are discussed below.

Firstly, the O&M costs of wind turbines are already lower for a long time in Austria than in Denmark. This is mainly caused due to less full-load hours and therefore less annual operation time. Hence, a technical service is not as often required as in Denmark and technical equipment is changed in longer intervals. The lower O&M costs in Austria are also based on the installation of wind parks rather than single wind mills and therefore the relative O&M costs drop as well.

As is mentioned above, Austrian wind turbines do not provide as many full-load hours as Danish wind mills. This disadvantage is because of the geographical situation of Austria. Since many Danish wind turbines are installed along the western shore of Jutland, where there are many windy days at high wind speeds, the energy output increases. This geographical disadvantage is even recognizable if Austrian wind mills are compared to Danish wind turbines that are erected inland, because Denmark is very flat and the wind from the North Sea blows over the whole country. Nowadays, the average full-load hours in Denmark vary between 2300 hours and 2550 hours, whereas wind turbines in Austria provide 2150 hours.

Finally, the levelized generation costs are influenced by the risk premium of the investors. Austrian investors attempt to achieve an as short as possible amortization period in order to guarantee that they receive the money back, even though the forecasted output cannot be achieved within the calculated time period. On the other hand, the operators are interested in longer amortization periods in order to decrease the generation costs and be competitive on the market. Therefore usually an amortization period of 15 years is considered.
In Denmark investors prefer to increase the discount rate that is taken into account in order to calculate the levelized generation costs. The difference between the real and the chosen discount rate is considered as the risk premium and guarantees a certain level of income even in cases the predicted output cannot be achieved. In Austria the higher the risk premium is chosen the less competitive the wind turbine gets on the electricity market. In order to avoid this, the calculations consider a risk premium of about three percent.

These three presented parameters are mainly influencing the levelized generation costs and causing the difference between Austria and Denmark as is illustrated in figure 8.4 below.

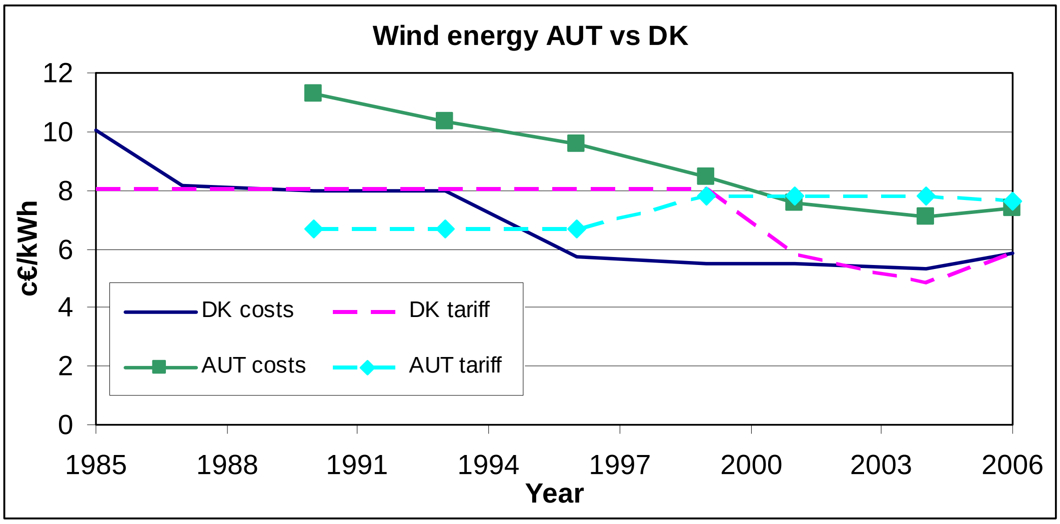

Figure 8.4 Comparison of the Austrian and Danish wind generation costs (straight lines) and the related feed-in tariffs (doted lines); Source Riso and E-Control

As figure 8.4 shows, the Danish generation costs are below the Austrian costs due to the before mentioned matters. Furthermore, in Denmark the generation costs are approximately covered by the feed-in tariffs whereas in Austria it depended on the federal state. Figure 8.4 also presents the feed-in tariffs for new wind mills in these specific years and the tariff of Austria until 1999 represents the federal state Lower Austria.

Generally, the experience curve of levelized electricity generation costs is a global process and therefore the reduction of the ex-work costs dropped by the same percentage in Austria and Denmark. In this way, Austria benefits from the experiences of other countries, like Denmark, which are more experienced in wind energy.

8.2.2 Generation costs of small-scale CHP plants

As in the case of wind energy no data of real electricity generation costs are available of small-scale CHP plants. Therefore, the calculated levelized generation costs are taken into account in order to discuss the differences between Austria and Denmark.

Primarily, the O&M costs of small-scale CHP plants are depending on the kind of fuel the plant uses. In a comparison of the annual O&M costs between Austria and Denmark hardly any difference is recognizable. Only the Danish costs are a bit higher due to the generally higher price level in the Scandinavian area.
Comparing the full-load hours of small-scale CHP plants, the different kinds of fuel have to be taken into account. Moreover, the full-load hours are depending on the fuel resources and therefore some more expensive CHP plants are only used to cover the peak load, whereas others are covering the base-load as well, hence possessing higher full-load hours. Due to the fact that CHP plants only achieve high efficiency rates if they are producing electricity and heat, their production is connected. In that way the full-load hours are also depending on the heat demand of the connected District Heating System or company because small-scale CHP plants are controlled by the heat demand.

The main difference in operating small-scale CHP plants in Austria and Denmark is the development of the heat refunds. Since Austrian small-scale CHP plant owners receive a fixed, negotiated income per sold Gigawatt-hour heat, the Danish CHP plant owners receive a negotiated income as well but at least an amount in order to cover the costs caused by the heat generation. Nevertheless, the total income of heat generation is almost the same in both countries, because the slightly higher price in Denmark is compensated by an additional heat subsidy that Austrian small-scale CHP plants receive.

In order to compare levelized electricity costs, figure 8.5 presents the calculation of a five Megawatt solid biomass plant and a five Megawatt waste incineration plant.

Moreover, figure 8.5 illustrates the national feed-in tariffs of these plant types erected in 2003.

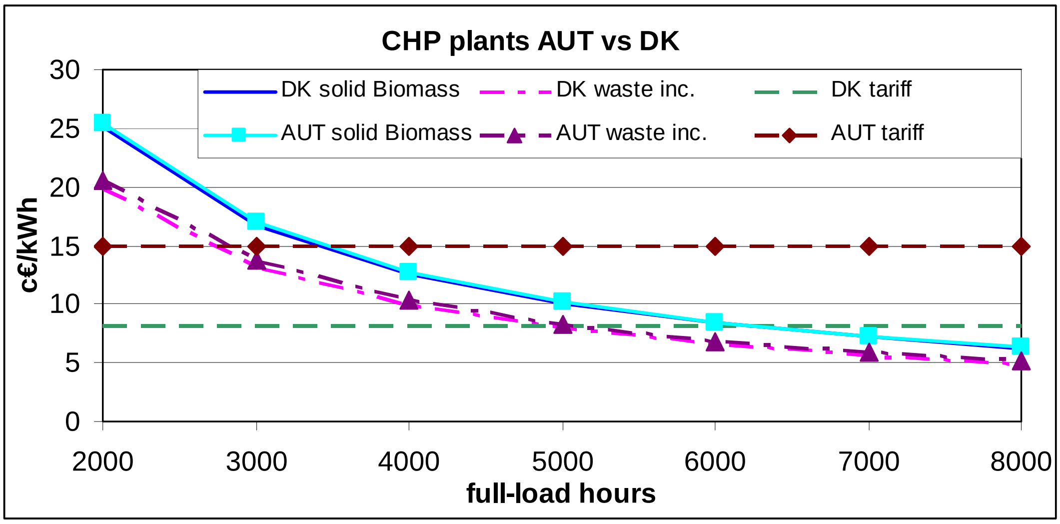

Figure 8.5 Small-scale CHP electricity generation costs Austria versus Denmark and the related feed-in tariffs.

Figure 8.5 illustrates that generation costs in Austria and Denmark are almost the same, only the Austrian subsidies are much higher. Therefore, Danish CHP plants can regulate their heat income themselves.

8.3 Balancing system and costs

In order to compare the balancing system in Austria and Denmark it has to be taken into account that Denmark is part of the Nordic power market NordPool and a jointly balancing system is operating there, whereas Austria has to balance its power market itself.

Austria is divided into three control areas, where in each control area several balancing groups are controlled by one balancing group coordinator. Balancing groups are financial institutions that combine electricity consumer and suppliers. Moreover each control area contains one eco-balancing group that is responsible for the total renewable electricity within its control area. Every balancing group informs the coordinator via schedules about the planned power exchange. With respect to this information, the coordinator accepts or declines the power exchanges and activates regulative power in cases of derivations from the final schedule. Moreover, the power clearing company holds the bids for regulative power in form of the amount of power and the related prices. The balancing group coordinator always activates the cheapest regulative power plant within his area in order to balance the market. The local distribution system operator measures the real consumption and generation and informs the related balancing groups as they calculate the balancing costs. An exception is the eco-balancing groups. They are not balancing responsible and their balancing costs are covered by the end-consumer by an extra charge on the grid tariffs.

On the other hand, the Danish power market is part of the NordPool market. Consumers and generators are represented by retailers and traders who inform the balancing responsible company about their schedules of power exchange. Generators which are providing regulative power additionally make bids in form of amount and related price of balancing power. This information is finally sent to the NOIS (Nordic Operation Information System) market that collects all balancing power bids from the Scandinavian countries Denmark, Norway, Sweden and Finland in steps of fifteen minutes. In case of a derivation from the planned power schedule in Denmark, the TSO requires to buy the cheapest available balancing power from the NOIS market, independent of the geographical activation. The only requirement is, that between the place of balancing demand and the balancing power plant there is no grid bottleneck. The advantage of the NOIS market is that several hydro plants from Norway and Sweden which are providing cheap power take part. This system works only in Zealand, the Eastern part of Denmark, because the Western part Jutland is not connected to the Nordel grid via AC lines and balancing is not realizable via DC lines. Therefore, Jutland is balancing responsible itself, with the disadvantage of higher costs.

Nowadays, there are hardly any differences regarding the technical requirements in order to provide regulative power within Austria and Denmark. It is required in both countries to provide at least ten Megawatt of electrical power and furthermore, the power plants have to able to up- or down-regulate their power within fifteen minutes. In Denmark, small-scale generators are allowed to jointly provide the amount of ten Megawatt power and therefore distributed generators are not excluded form the balancing market and an even more grid-efficient balancing activation is possible.

As wind energy is one of the biggest orign of balancing energy, a comparison of Austria and Denmark shows the impact on it.
Since Austria follows the subsidy scheme of feed-in tariffs on wind energy generation, wind turbine owners are not balancing-responsible themselves. Each wind mill generates as much energy as possible and feeds into the eco-balancing group who balances the whole group. Furthermore, wind energy counts as volatile renewable energy source and there are still several ongoing projects in order to improve the forecast methods. In Austria, wind energy has always to be predicted one day in advance but on days before a holiday or weekends the complete, estimated wind energy generation until the next working day has to be published. This problem causes a high error rate and therefore requires more regulative power.

The Danish situation has changed in the year 2003. Until that year, wind energy generators were subsidized by guaranteed feed-in tariffs and neither have they been balancing-responsible. In that time, wind energy was considered as a priority dispatched energy source. Since January 1st, 2003 the subsidy scheme changed from a feed-in system to a premium subsidy. Additional wind generators became balancing-responsible, which paid the regulative power themselves. Moreover, wind energy is only predicted for one day in advance regardless the weekdays and therefore creating less forecasting errors.

Due to the different balancing systems, the price per kilowatt-hour balancing electricity is much higher in Austria than it is in Denmark. The overall balancing costs in Austria amount to about 10 €/MWh, whereas a higher clearing price is considered as well as the receipts due to down-regulation. Compared to a balancing price of only 1-3 €/MWh in Denmark, Austrian power plants pay about four times more. Mainly responsible are the energy generation forecast error of 45 percent in Austria compared to only 27 percent in Denmark, the general higher spot market price and the smaller balancing areas in Austria.
Figure 8.6 below demonstrates the development of the balancing prices in Austria and Denmark. In both countries the costs are fluctuating depending on the present balancing demand and the related regulative power bids.

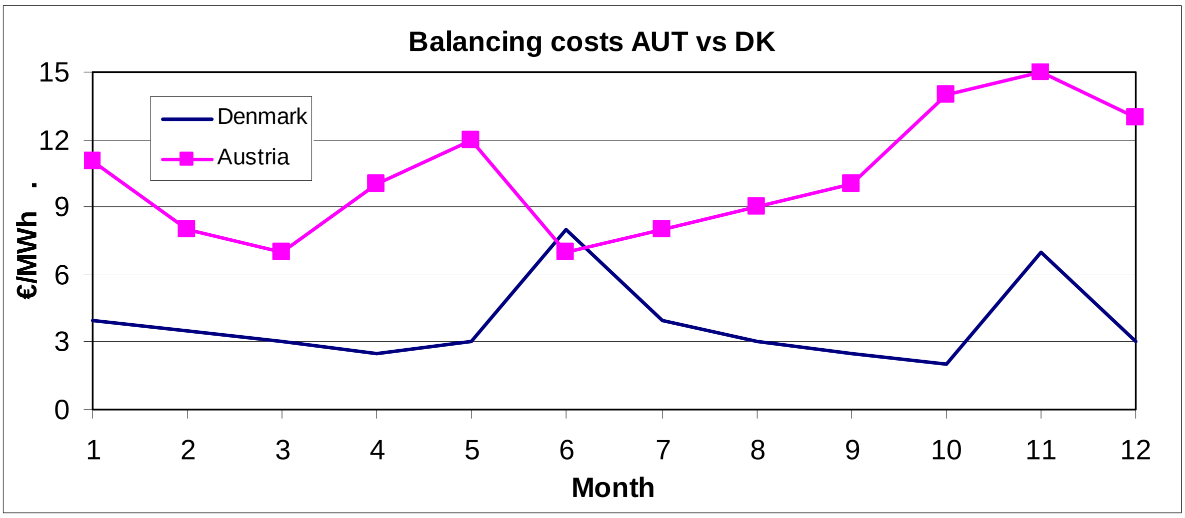

Figure 8.6 Total balancing costs in the year 2005 in Austria and Denmark in Euro/MWh 2006; Source (Morthorst, P.E., 2007 and APCS)

8.4 Grid topology and costs

This subchapter addresses the changes of the grid topologies at different voltage levels and the impact of distributed generation on it. Additionally, the costs of grid reinforcement and extensions in both countries are compared. In a second part, the socializing methods are compared and the resulting grid tariffs are discussed.

8.4.1 Grid topology development

As the total electricity grid is divided in a distribution grid up to 110kV and a transmission grid at voltage levels above 110 kV, the main impacts of distributed generation are only to be recognized in the distribution grids. Although different parts of the transmission grids had to be reinforced in order to deal with the newly installed electricity generators, these investments are comparatively small.

In Austria almost all newly installed wind generators and small-scale CHP plants are connected to the grid via direct 20 kV or 30 kV lines to the next 110 kV substation, and only the internal installation of the wind park is performed at 10 kV. So the existing 10 kV grids were not designed strong enough. Moreover, some 110 kV substations had to be erected respectively reinforced in order to feed the excess energy into the transmission lines. The impact on the transmission lines is much smaller because only in the Eastern part of Austria a 220 kV cable had to be reinforced yet, but with an increasing share of wind energy it is expected to rise.
Since Austria implemented the Deep Cost Approach, every wind mill owner bears the grid installation costs himself and the cables were only designed for the power of their own wind parks. Therefore, no jointly utilization of grid connection is installed, resulting in less efficient connection utilizations.

Danish distributed generators are by contrast connected to the local 10 kV grids, but nevertheless these distribution grids had to be enlarged and reinforced. Furthermore, some higher voltage grids had to be reinforced as well, although the 60 kV and 150 kV grids were originally designed strongly. Since Denmark installed the Shallow Cost Approach, the local Distribution System Operators were responsible to connect every new small-scale generator to their grids and they also had to pay for the connection. When these generators were connected to the local grids, a more efficient utilization was guaranteed due to a more foresighted planning of the grid extensions by the System Operators.

Figure 8.7 below points out the necessary grid extensions in the distribution grids between 10 kV and 30 kV within the past few years in Austria and Denmark.

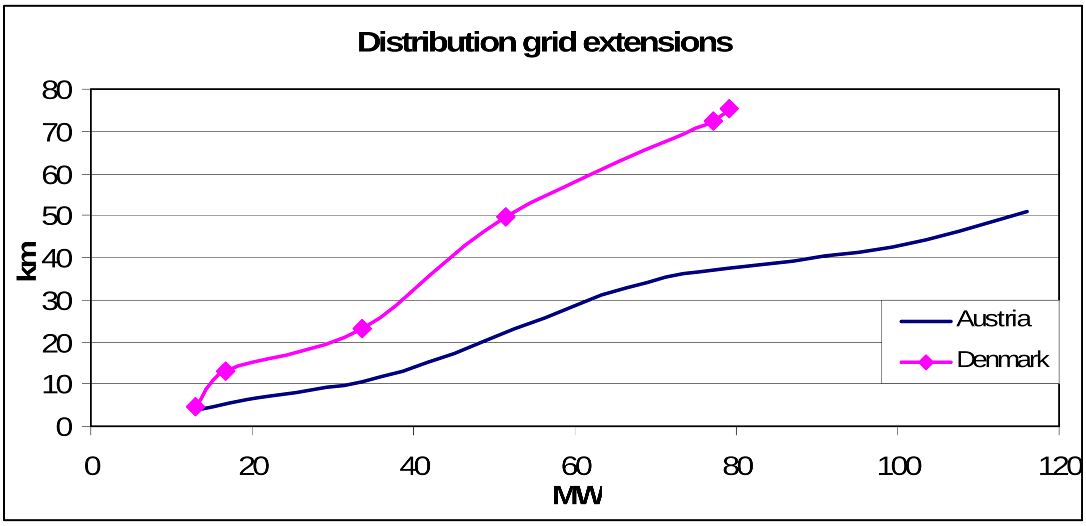

Figure 8.7 Distribution grid extensions due to wind park grid-connections in Austria and Denmark

Although Denmark uses a more efficient grid connection Approach, the last years required a higher enlargement of the grid. This is caused by the fact that Denmark had already a high penetration of wind turbines and therefore newly installed wind parks are far out in the countryside. Furthermore, it has to be taken into consideration that Austria had to additionally extend the 110 kV grid by 119 km in order to handle the newly installed wind energy.

Since most wind generators and small-scale CHP plants in Austria and in Denmark are erected in the countryside hardly any difference at the grid connection costs is recognizable. Digging trenches in the city is about four times more expensive than on the countryside and moreover, trenches in the countryside are made by a plough in order to reduce the costs again.
As Denmark usually uses aluminum cables of the type 3x240mm² AL, Austria uses copper cables of the type 3x500mm² CU. Nevertheless, the total connection costs are more influenced by the work prices than by the ex-work prices.

Figure 8.8 demonstrates the relative connection costs of wind turbines and small-scale CHP plants at the distribution level only. The additional costs in Austria caused by the reinforcement and enlargement of the 110 kV grids are covered by the grid allocation fee and are therefore not regarded in figure 8.8.

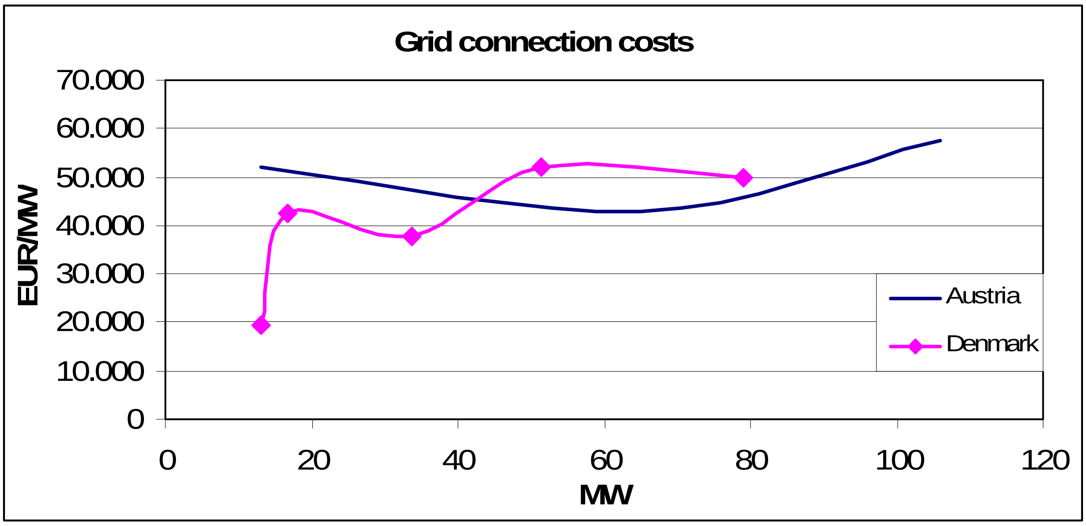

Figure 8.8 Relative distribution grid connection costs Austria versus Denmark; Prices Euro 2006

8.4.2 Grid costs socializing methods

The different Cost Approaches in Austria and Denmark are resulting in different socializing methods of the resulting connection costs.
The Deep Costs Approach in Austria requires generators to bear the installation costs themselves, whereas in order to cover the costs of reinforcements and extensions of the high voltage grid, all grid users have to pay a grid allocation fee. Furthermore, different kinds of grid tariffs are collected by the System Operators in order to cover the expense for grid maintaining, measuring service and grid losses. These tariffs depend on the voltage level but ignore the amount of consumed or generated energy.

The Danish Shallow Cost Approach requires the Distribution System Operators to enlarge their grids according to the demand of distributed generators. Therefore, the resulting costs are covered by the Transmission System Operator according to a pre-defined model. In order to provide incentives for the local Distribution System Operators to run their grids stable and efficiently, this model may cover even more than the real expenses in case the grid was designed strong enough and no work had to be done. In this way, the model is completely independent of the real expenses and only refunds the calculated amount. The refunds the Transmission System Operator pays, are collected by the end-consumer in the form of Public Service Obligations, which every costumer has to pay per consumed kilowatt-hour. This model is presented in table 4.4. In this way, the grid connection costs due to distributed generators are socialized all over Denmark and no disadvantage appears for consumers in the North-West part where most of the wind mills are erected. Additionally, distribution and transmission tariffs are charged to the grid users excluding renewable electricity generators. These tariffs are annually approved of by the Danish Regulatory Authority.

8.5 Sensitivity analyzes

The parameters in the above mentioned subchapters have different impacts on the electricity generation costs. These influences are discussed in the following part with respect to the national regulations. The first part addresses the influences of risk management, balancing costs and grid connection costs on wind energy generation. Finally, the impact of grid connection costs on electricity generation of small-scale CHP plants is shown, as well as the sensitivity of heat revenues.

8.5.1 Sensitivity analyzes of wind electricity costs

Since investors in Austria and Denmark are mainly interested in a short pay-back period, usually risk management is considered at the levelized electricity generation costs of wind energy. As is mentioned before, Austria and Denmark are using different methods of implementing the risk management. Austrian investors reduce the amortization period in order to guarantee a maximum pay-back time whereas Danish investors raise the discount rate in order to achieve a maximum pay-back time. Both methods increase the generation costs and therefore the competitiveness decreases, so a compromise has to be found.

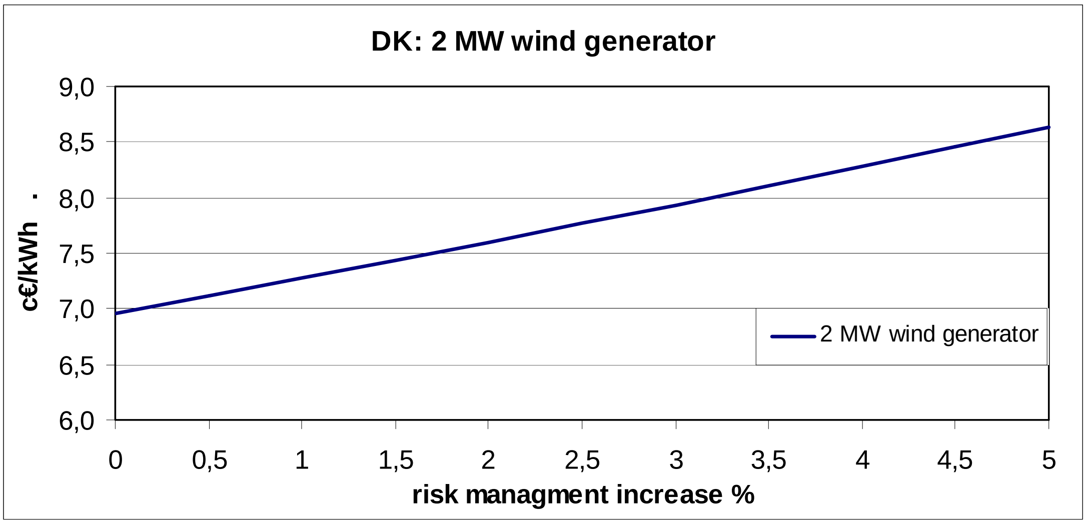

Figure 8.9 Risk management sensitivity of a Danish 2 MW wind turbine installed in the year 2006

Figure 8.9 above shows the risk management sensitivity in levelized electricity generation costs of wind energy. As demonstrated, the generation costs are highly sensitive to risk premium rates like they are used in Denmark. Usually, risk premiums up to 3,5 percent are considered, increasing the generation costs of one Eurocent.

A further major difference between the Austrian and Danish system is the balancing system and the related costs. Due to the different systems in forecasting the electricity generation and the bigger power market the balancing costs in Austria are about four times higher than in Denmark. An error rate of 45 percent in Austria increases the sensitivity to balancing costs dramatically compared to only 27 percent in Denmark. Moreover, due to the higher full-load hours in Denmark the balancing costs are divided by more kilowatt-hours and keep a competitive generation price of wind energy.

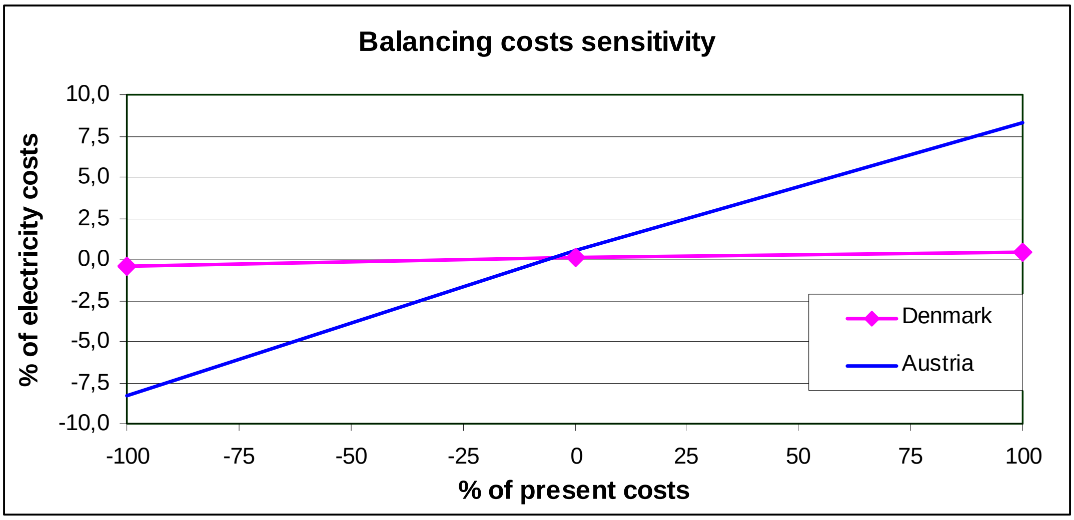

Figure 8.10 Balancing sensitivity of wind mills, comparing a forecasting error of 45 percent in Austria and 27 percent in Denmark

It has to be mentioned that Austrian wind generators are not balancing responsible and their costs are covered by the end-consumers, while Danish wind generators are balancing responsible since the year 2003 and pay their costs themselves. While the average balancing costs in Austria amount to 10 Euro per MWh, Danish costs vary between 1 Euro per MWh and 3 Euro per MWh.

Finally, the grid connection costs in Austria and Denmark differ widely from each other. While Danish wind turbine owners only pay the costs of the internal grid installation, Austrian wind power owners have to cover the total grid connection costs plus the costs of reinforcement of the high voltage grids. Therefore, the grid connection costs in Denmark amount to only a few percent of the total investment of a wind turbine while the percentage of grid connection costs in Austria contribute up to fifteen percent of the total investment. Moreover, the generation costs in Austria are more sensitive to the grid connection costs than in Denmark, caused by higher full-load hours in Denmark.

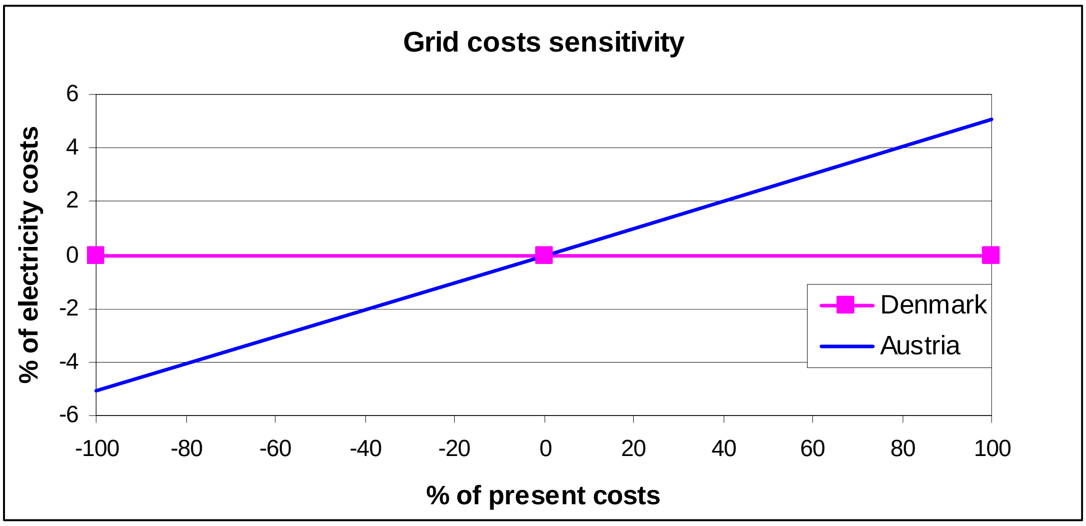

Figure 8.11 Sensitivity to grid connection costs of Austrian and Danish wind turbines

Approximately, Danish wind turbine owners pay 70 EUR/MW of the installed generator capacity for grid connection costs, whereas Austrian investors have to pay 150.000 EUR/MW due to the different national directives.

In general, the generation costs are not as sensitive to grid connection costs as to balancing power or even the risk premium. Most manipulations of the generation costs happen through the decision of a risk premium.

8.5.2 Sensitivity analyzes of small-scale CHP plants

Thus, the same grid connection approaches for small-scale CHP plants are implemented in Austria and Denmark. For wind turbines, the sensitivity of these costs is discussed. Since the total investment costs of a small-scale CHP plants is about three times more than for wind turbines, the grid connection costs are not considered as main expenses for CHP plants. Moreover, small-scale CHP plants are mostly erected close to a District Heating System in order to avoid heat losses, and therefore the electricity grid connection is short as well.
Figure 8.12 below demonstrates that small-scale CHP plants[24] are almost insensitive to grid connection costs due to the above mentioned influences. Even costs like they appear in Austria increase the electricity generation costs only by 0,6 percent.

[24] A biomass CHP plant is considered with an electric power of 10 MW at 6000 full-load hours and thermal output of 20,8 MW at 2700 thermal full-load hours.

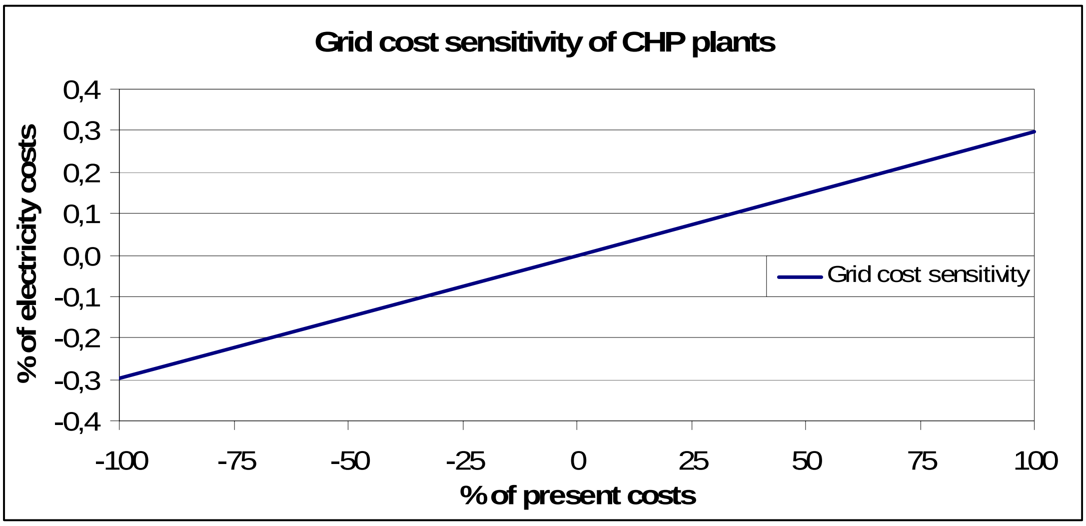

Figure 8.12 Sensitivity electricity generation costs to grid connection costs of small-scale CHP plants

Furthermore, small-scale CHP plants are highly sensitive to achieved heat revenues. While the heat revenues in Austria are mostly negotiated between the District Heat companies and the CHP plants, Danish CHP plants are allowed to cover the gap between their expenses and the income from electricity due to heat revenues. Nevertheless, these heat revenues have to be approved of by the Danish Regulatory Authority, whereas CHP plants are not allowed to make any benefit out of the heat revenues. Therefore, heat revenues in Denmark vary between 32 Euro per MWh and 45 Euro per MWh, whereas the heat in Austria is sold at approximately 38 Euro per MWh.

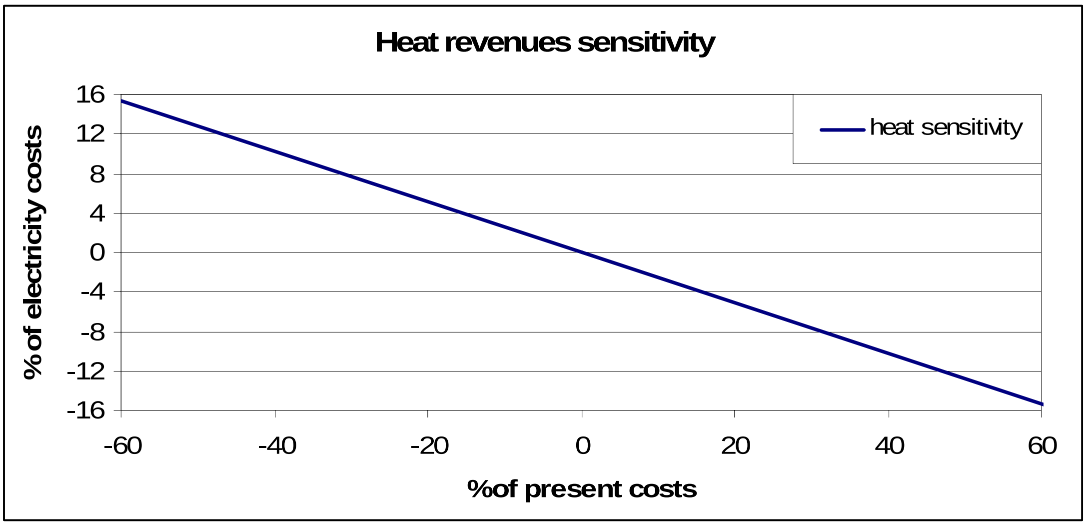

Figure 8.13 Electricity generation costs sensitivity to heat revenues of small-scale CHP plants

Figure 8.13 above illustrates a strong sensitivity of electricity generation costs to heat revenues. This is caused by the fact that the levelized electricity generation costs are calculated only by the total investment of the small-scale CHP plant minus the heat revenues, accrediting the advantage of the CHP plants to the electricity generation.

9. Conclusion

As demonstrated before, several differences between the Austrian and the Danish electricity supply system exist. Since Denmark has the highest penetration of distributed generation within the EU, consequences and recommendations for the Austrian system can be drawn.

Firstly, the main arguments of the Danish national legislations which led to the high penetration of distributed generation are pointed out.
Since Denmark started already in 1973 to promote distributed generation of renewable energy sources due to the oil crises, several energy plans and directives got issued. Moreover, all directives from the European Union were implemented more strictly into the Danish national legislation in order to accelerate the development. Hence, distributed generation obviously requires a strong and serious promotion over a long period.
In order to install an efficient energy supply system with a high penetration of renewable energy sources, it is recommendable to switch from feed-in tariffs to a premium subsidy scheme after the introduction phase of the technology. Feed-in tariffs and priority dispatched guarantees were necessary, in order to introduce new generation technologies to the power market and cover their initially high generation costs. If this subsidy scheme is continued, an inefficient utilization of this generation technology is ensured because renewable generators produce electricity arbitrarily and not according to the demand. Therefore, the total subsidy amount increases and moreover, more balancing power is required, causing additional costs. The premium system is connected to a balancing-responsible approach of the generators as well. Hence, in the saturation phase of a new technology, the premium tariff as it was introduced in Denmark in 2003, is more efficient because it reduces the total subsidy amount and also the consumption of regulative power.
Generally, levelized generation costs of wind electricity in Austria nowadays amount to 7 c€/kWh whereas Danish wind turbines achieve cheaper costs about 6 c€/kWh, mainly caused by the higher full-load hours in Denmark. On the other hand are electricity generation costs of small-scale biomass CHP plants in Austria and Denmark only varying within a small range, mainly depending on the used kinds of fuel.
The high penetration of small-scale CHP plants in Denmark is caused by the national law of a connection obligation to the local District Heating System of every dwelling. Due to the decreasing heat costs of households caused by the jointly used District Heating System, it was appealed of by the society. Since District Heating Systems are served by small-scale CHP plants, the connection obligation supported the development of distributed generation in Denmark.

Secondly, the differences in the balancing system of both countries are a crucial argument in the integration of renewable energy sources. Generally, the shorter the period of forecasting the generated power is, the less balancing power is required. Since wind energy is the most volatile energy source, several researches are being conducted in order to develop highly sophisticated wind prediction technologies.
The Danish Transmission System Operator requires its balancing-responsible groups to forward the planned power schedules of generation and consumption always one day in advance, whereas Austrian balancing groups have to inform their balancing group coordinators one day in advance before a working day and on the last working day before weekends and holidays. Hence, the forecasting period in Austria is much longer than in Denmark, which results in higher forecasting errors. This advantage of the Danish system decreases its balancing costs in comparison to the Austrian system and is therefore much more favorable for wind energy and other distributed generation. While Austrian electricity schedules of demand and generation show a prediction error of 45 percent the Danish schedules hold only 27 percent, reducing the balancing costs by more than one-third.
Since Danish renewable electricity generators are balancing- responsible, a more efficient operation is guaranteed. As long as the balancing costs were covered by the Transmission System Operator, the generators did not consider the electricity demand and therefore caused a lot of regulative power. This disadvantage in the balancing responsibility still happens in Austria. If the consumption of regulative power drops, the costs of balancing energy decrease as well, because only the cheaper regulative power plants get activated. This fact, and the additionally lower electricity price level in Denmark, are considered by comparing the costs in Austria of 10 €/MWh to only 1-3 €/MWh in Denmark. Furthermore the bigger area of the Danish balancing market also results in lower balancing costs. The low balancing cost reduce its impact on the electricity generation costs of balancing responsible renewable energy sources in Denmark to only 2,8 percent.

Finally, the two different approaches of grid connection influence the development of distributed generation. Primarily, the Danish Shallow Cost Approach is much more favorable for distributed generation than the Austrian Deep Cost Approach. The first distributed generators in a pre-defined area in Austria bear also the grid extension costs in order to grid connect their power plants, whereas the Danish approach does not affect the generators. Therefore, Austrian investors are not that interested in erecting a distributed power plant at locations where no grid or only a weak grid infrastructure exists. The Shallow Cost Approach avoids this problem and therefore the penetration of distributed generators in Denmark is influenced positively.
Thus, Austrian distributed generators have to bear the grid connection costs themselves, every plant installed direct lines to the next 110 kV substations and therefore an inefficient grid extension resulted. These grid connections generally

cause 50.000 €/MW, and additionally 100.000 €/MW of reinforcing costs of the existing high voltage grid infrastructure. The newly installed grid extensions are now operated by the Distribution System Operators and the resulting costs are socialized in the grid utilization tariffs. In Denmark most Distribution System Operators are owned by the communes or jointly owned by the consumers and are therefore interested in a cost-efficient operating of their grids. Because these Operators are responsible for their grid extension, a foresighted planning avoids additional investments of the connection of further plants and therefore the system tariffs decrease. Generally, Danish distributed generators pay 70 €/MW in order to cover the expenses of the internal grid connection and the Distribution System Operators pay about 50.000 €/MW for the total grid connection, whereas their expenses are socialized by the Transmission System Operator. Since Denmark is considered as an electricity transit country, the transmission grid is strongly designed so far, hence no additional investments were required. In this way incentives are given to investors, supporting an increasing penetration of distributed generation.

Due to the high penetration of distributed generation, a more efficient balancing is possible because regulative power plants are able to be activated close to the demand in order to transmit the balancing power over big distances in the grid.

If Austria would implement the Shallow Grid Connection Approach as well, the total electricity generation costs of wind energy would decrease by 0,3 c€/kWh, almost five percent of the generation costs nowadays.

Table 9.1 Main comparison between the Austrian and Danish electricity system

	Austria	Denmark
Subsidy scheme	Feed-in tariff	Premium
Balancing system	Non-balancing responsible	Balancing responsible
Grid connection approach	Deep cost approach	Shallow cost approach
Percent RES-E	4,7[25] %	30,4 %
Percent DG	10,4 %	47 %

Generally, Danish laws are much more favorable for distributed generation and renewable energy sources. Due to that regulative background, an economically feasible and environmentally friendly energy system was developed. Thus, the politically enforced introduction of distributed generation decreased the total energy costs of Danish households, when the socialized subsidy scheme was accepted at the Danish population. Researches and operation of renewable energy will continuously improve the discussed technologies and therefore decrease the generation costs. Although Austria cannot copy the Danish system it is a good model in order to integrate distributed generation, especially in the balancing and grid connection matters. Essential directives, as the grid connection approach of

[25] Excluding large-scale hydro plants in RES-E, amounting to 62,5 percent

distributed generators should be discussed in Austria in order to promote the development of distributed generation. Since Austria cannot achieve an penetration of wind energy as high as in Denmark due to the geographical situation, the Shallow Cost Approach would also support the development in small-scale hydro plants. Several discussions are already ongoing in Austria and therefore a new amendment of the Austrian “Ökostromgesetz” is expected to be introduced in the near future, favoring RES-E and distributed generation.

10. Summary

Since electricity systems of nowadays are increasingly penetrated by renewable energy production, the integration and political support of distributed generation became a main topic. Denmark developed good strategies in order to handle these matters. Therefore, this diploma thesis presents and compares the results of the chosen solutions in Austria and Denmark.
The technically feasible grid integration of distributed generators supports the efficiency of electricity systems because a closer generation to the demand side discharges the distribution grids and therefore less grid reinforcements, losses and grid extensions occur. Moreover, a high percentage of installed distributed generators are renewable energy converters in order to meet the national and international agreements on primary energy savings and CO2 reductions. In this way, Denmark is good example how to implement RES-E into the national electricity system.

Since wind electricity costs are not economical feasible yet, different subsidy schemes were introduced over time. Denmark and Austria guaranteed fixed feed-in tariffs above the electricity market price in order to offer incentives for investors. Austria implemented different tariffs in each federal state, leading to an inefficient utilization of these tariffs. Most wind turbines were erected in those federal states which paid the highest tariff, instead of places where wind turbines achieve the highest electricity output. In the year 2003 Austria harmonized its tariff in order to avoid this problem. On the other hand, since the penetration of wind energy in Denmark increased strongly, Denmark switched from a guaranteed feed-in tariff to a premium system. This change took place in the year 2003 and since then, all wind turbines sell their electricity on the market price plus an additional small premium.

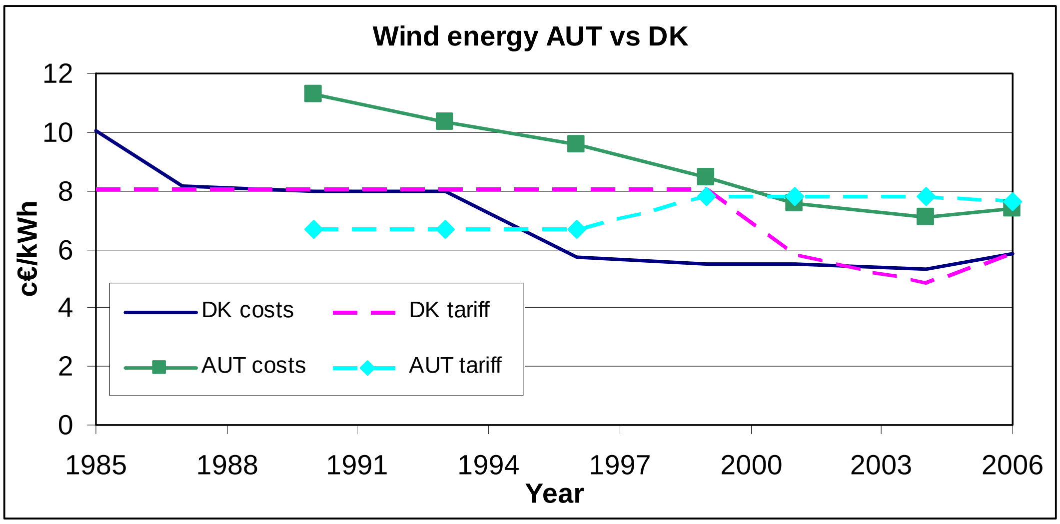

Figure 10.1 Comparison of the Austrian and Danish wind generation costs (straight lines) and the related feed-in tariffs (doted lines); Source (Morthorst, P.E; E-Control; 2007)

Figure 10.1 demonstrates that the harmonized grid tariffs in Austria are covering the costs of wind turbine owners, whereas before 2003 wind electricity generation costs have been above the feed-in tariff. The Danish premium system was adopted in 2005 in order to cover the increasing electricity generation costs and offer a feasible support.

The situation for small-scale CHP plants is similar as for wind turbines. Guaranteed feed-in tariffs in Austria and Denmark were introduced and in the year 2003 Austria harmonized the tariffs, whereas Denmark switched to a premium model. Electricity generation costs are mainly depending on the technology and the full-load hours. Since full-load hours of small-scale CHP plants are defined by the heat demand, the same costs arise in both countries. Danish CHP plants use water tanks, in order to generate electricity at times with low heat demand as well and increase their full-load hours.

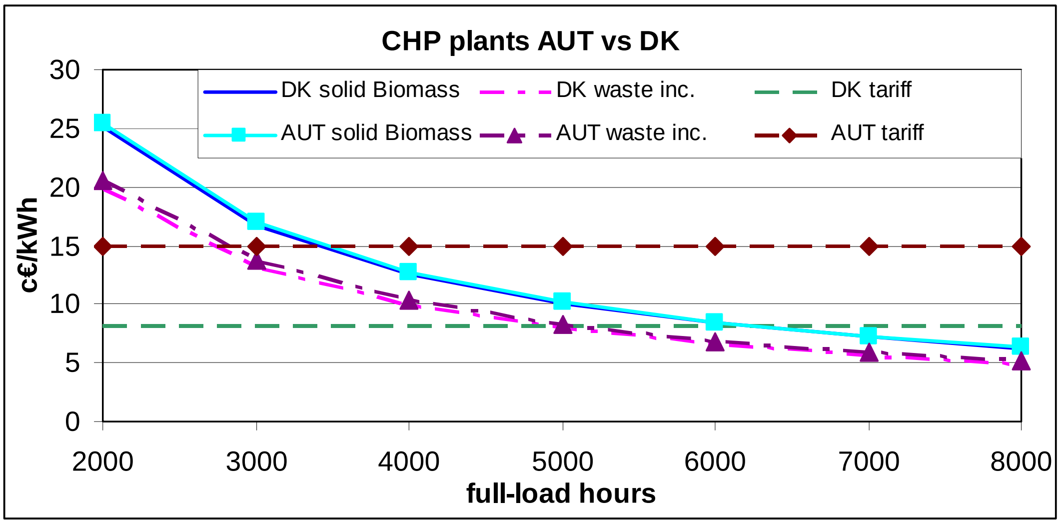

Figure 10.2 Small-scale CHP electricity generation costs Austria versus Denmark and the related feed-in tariffs.

Due to the high feed-in tariffs in Austria, illustrated in figure 10.2, small-scale biomass CHP plants are already economically feasible at low full-load hours. These high feed-in tariffs are incentives for investors. On the other hand, the District heating infrastructure in Austria is not as good developed as in Denmark and therefore the heat demand is smaller. Installing new District Heating systems is very expensive, decelerating the penetration of small-scale CHP plants in the Austrian electricity system.

In Denmark the difference between the electricity spot market price and the guaranteed tariffs, are covered by Public Service Obligations (PSO), which every electricity costumer has to pay per consumed kilowatt-hour. This PSO is calculated and collected by the Transmission System Operator every three month.

Since renewable electricity is considered as volatile energy sources, the balancing method is an important argument. Because the Danish power market is part of the Nordic market NordPool, a jointly balancing system is in operation as well. The Transmission System Operator is responsible for the physical balancing of this area whereas the regulative power is provided by any approved power plant in the Nordic power market as long as no grid-bottlenecks appear. Every power plant nominates the balancing power it can provide at the Nordic Operation Information System (NOIS), and in case of deviation from the planned electricity generation and consumption the TSO buys the required balancing power at this market. An advantage of the Nordic market is the high percentage of hydro water plants, because they provide cheap electricity and are able to regulate their generation within a short time period. Hence, the total balancing price in Denmark is comparatively low and amounts to only 1-3 €/MWh.

On the other hand, Austria is divided into three control areas, where in each control area several balancing groups are controlled by one balancing group coordinator. Moreover each control area contains one eco-balancing group that is responsible for the total renewable electricity within its control area. The power clearing company holds the bids for regulative power in form of the amount of power and the related prices. In case of deviations from the planned schedule the balancing group coordinator activates the cheapest regulative power plant within his area in order to balance the market. The local distribution system operator measures the real consumption and generation and informs the related balancing groups as they calculate the balancing costs.

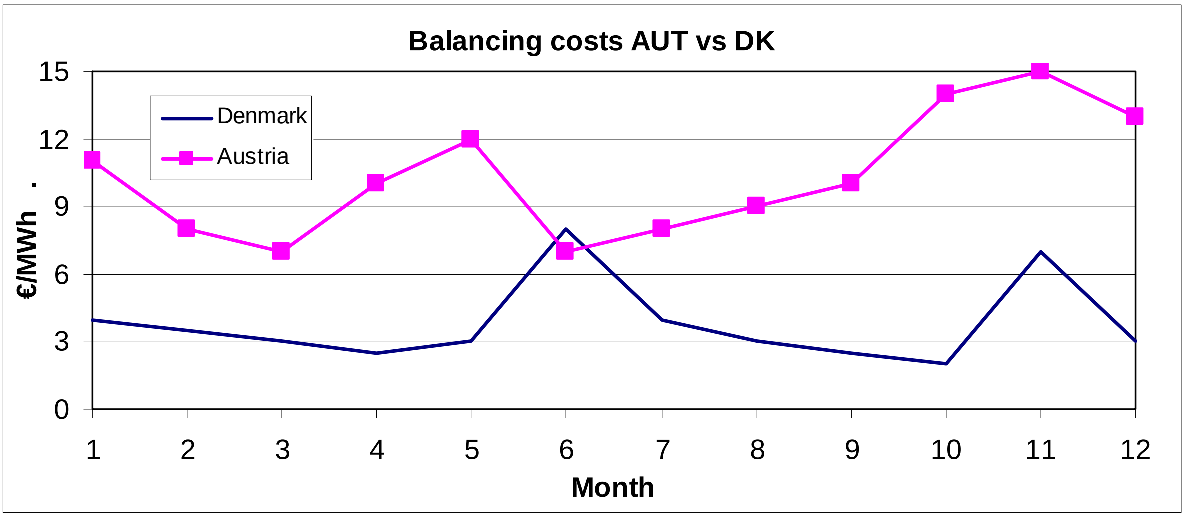

Figure 10.3 Total balancing costs in the year 2005 in Austria and Denmark in Euro/MWh 2006; Source (Morthorst, P.E., 2007 and APCS)

The mentioned advantage of the Danish balancing system is reflected in balancing costs in figure 10.3. Moreover the balancing costs are strongly influenced by the fact

that Austrian renewable electricity generators are not balancing responsible and Danish ones are.
Since renewable electricity generators in Denmark are balancing-responsible since 2003 they have to sell their generated electricity according to the forecasted schedules on the market itself. In case of deviations from the planned electricity generation, the owners of the plants have to pay their caused balancing power. Before 2003 the Transmission System Operators paid the balancing power and therefore generators produced as much electricity as possible in order to receive the subsidies.
In Austria, renewable electricity generators financially feed into the eco-balancing group. This group is not balancing responsible and their balancing costs are covered by the end-consumer by an extra charge on the grid tariffs. Hence, Austrian generators do not care about the balancing power they cause and therefore much more balancing power is demanded, increasing the price of it.

In order to integrate distributed generators to the grid, two different approaches can be identified, the Deep Cost Approach and the Shallow Cost Approach. Denmark has chosen the Shallow Cost Approach, which means that it is the System Operators' responsibility to provide a reliable grid for every applicant. Therefore every distributed generator has only to bear the connection costs of its power plant to the closest 10 kV grid node. In case the plant gets physically connected on a different voltage level or some grid reinforcements or extensions have to be done, the Distribution System Operators have to bear these costs. On the other hand, the System Operators socialize these costs according to a model. The refunds are shared among all electricity costumers due to a Public Service Obligation per consumed kilowatt-hour.
The Transmission System Operator, who collects the Public Service Obligation, refunds only the costs according to that model, disregarding the real investments in the grid. Hence, a foresighted and strong planned distribution gird avoids investments with every connection of a new electricity generator. Nevertheless the responsible Distribution System Operator receives refunds according to the model, even though no investments have been necessary.

Table 10.1 Refunds of the 3,3 MW wind park, 4510 meters apart from the 10 kV grid Prices in Euro 2006

3,3 MW wind park in 1998				Installed capacity	3,3	MW
	costs EUR/m	length m		cable typ	3x150 AL	
					EUR 2006	%
trench city	64,05	74,6		trench refunds	74.990,8	41,7
trench country	19,22	3.654,0		cable refunds	104.724,4	58,3
cable	28,09	3.728,6		total refunds	179.715,3	100,0
				total expenses	236.748,5	100,0
costs to cover by the DSO					**57.033,3**	**24,1**

Table 10.1 points out that approximately 75 percent of the necessary investments in the distribution grid are refunded by the Public Service Obligations. This efficient grid connection approach reduces the grid tariffs per consumed kilowatt-hour. On the other hand, the Public Service Obligation declined as well, because an increasing spot-market price closed the gap between the electricity price and the guaranteed tariffs for RES-E.

Austria implemented a Deep Costs Approach and therefore new electricity generators have to bear all arising costs of their grid connection. Moreover, a contribution to the local system operator has to be paid in order to cover his costs for reinforcing or extending the high voltage grid. This contribution fee is applied different, depending on the federal state and the energy source. So, in Lower Austria the total investments in the high voltage gird are shared among all owners of wind energy converters to same parts, whereas in Burgenland the prices are allocate according to the each wind turbine separately. Once the connection lines to the closest substations are built and paid by the generators, the lines are operated by the local Distribution System Operators who are also responsible for safety and reliable operation. This approach results in a constant growth of the distribution grid because no power plant owner expands the grid more than his power plant requires, only to avoid further grid investments.

On the other hand, costs for measuring purposes, grid losses, operation and maintenance and grid utilization are shared among all electricity consumers by the grid tariffs, depending on the grid level and the federal state where they are connected. Generators pay only the grid contribution fee once they are grid connected and a system tariff per generated kWh electricity in order to cover the costs due to load variations.

Electricity generation costs respond to the presented parameter with different sensitivities depending on the source of energy.

Table 10.2 Sensitivity analyzes of electricity generation costs in Austria and in Denmark pointing out the impact at a variation of hundred percent of the different, listed parameters.

		Austria		Denmark	
		-100 %	+100%	-100 %	+100 %
Balancing costs	Wind	-8,25 %	8,25 %	-0,38 %	0,38 %
Grid connection costs	Wind	-5,08 %	5,08 %	0,00 %	0,00 %
Grid connection costs	CHP	-0,30 %	0,30 %	-0,30 %	0,30 %
Heat revenues	CHP	37,8 %	-37,8 %	37,8 %	-37,8 %

Table 10.2 presents the sensitivity in electricity generation costs at a variation of different impacts as the grid connection costs, the balancing costs and the heat revenues of small-scale CHP plants. These parameters are varied within a range of plus/minus hundred percent showing the respond in the electricity generation costs of wind energy and CHP plants.
Austrian wind electricity generation costs are strongly sensitive in balancing costs due to expensive balancing power, whereas small balancing costs in Denmark do not influence the generation cost so strong. In present, balancing costs in Austria amount to 10 EUR/MWh and only to approximately 2 EUR/MWh in Denmark. On the other hand, are Austrian wind electricity generators not balancing responsible and therefore the higher generation costs are covered by the electricity consumers.
Furthermore the Shallow Costs Approach of grid connection, as it is implemented in Denmark leads to an insensitive respond of connection costs variation because the total connection costs, the wind park owner has to pay amounts to 70 EUR/MW which are included in the investment costs and only covering the internal cabling. The rest of the costs are paid by the Distribution System Operators. Compared to that, the Austrian Deep Cost Approach of grid connection reflects a sensitivity of five percent because Austrian wind turbine owners pay approximately 150.000 EUR/MW of grid connection cost.

Since investment costs of small-scale CHP plants are about three times higher than of wind parks, the grid connection costs play only a small role in the electricity generation costs of CHP plants. Therefore, small-scale CHP plants are very insensitive in grid connection costs only amount to 0,3 percent in Austria and Denmark. No difference is recognized, because the same kind of technology, which is dominating the generation costs, is installed in both countries.
Thus the advantage of small-scale CHP plants, producing heat and electricity, is accredit to the electricity generation, the plants are very sensitive in the revenues of heat. Nowadays plants receive a payment of 35 EUR/MWh heat up to 40 EUR/MWh in Austria as well as in Denmark and therefore they are highly sensitive.

The favorable legislations for distributed generation in Demark are reflected in figure 10.4 with a four times higher share of distributed generation in Denmark as in Austria. The percentage of renewable electricity generation excluding large-scale hydro plants is very small too, due to different influences like the geographical and political situation in Austria.

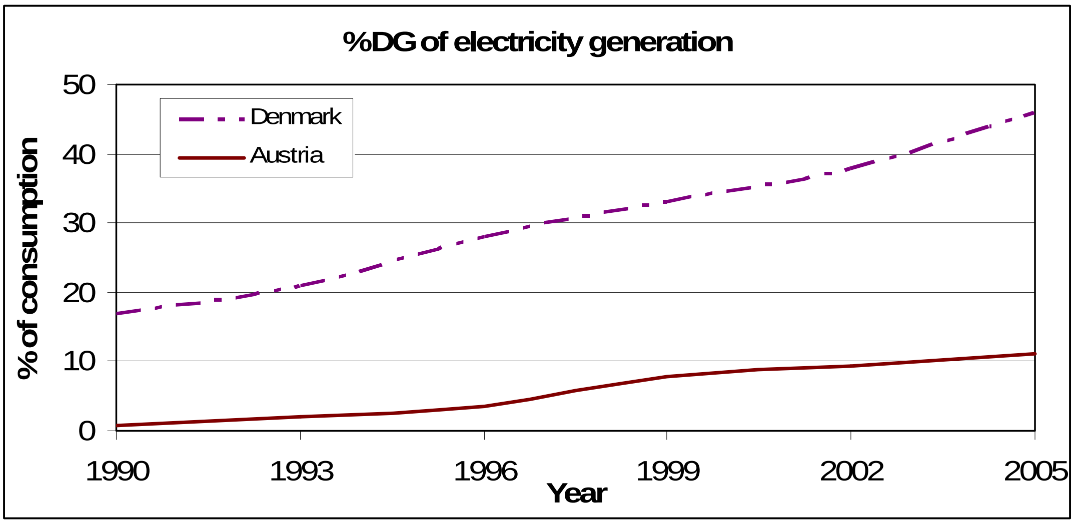

Figure 10.4 Percentage of electricity consumption generated distributed Source: (Pedersen, S.L.; 2007)

In conclusion, the more favorable Danish national politics in order to promote distributed generation have to be pointed out. The support scheme of renewable energy sources in Denmark started in the early seventies and the directives from the EU were always implemented more strictly.

The change of the subsidy scheme from feed-in tariffs to a premium subsidy associated with the change to a balancing responsible system of renewable electricity generation, lead to a more efficient integration of wind mills and small-scale CHP plants.

Furthermore, the Shallow Costs Approach of grid connection offers more incentives for investors to invest in renewable distributed generators, because the costs of a wind park connection amounts to approximately 70 EUR/MW in Denmark, compared to 150.000 EUR/MW in Austria. Moreover, the implementation of the Shallow Costs Approach results in a more efficient utilization of the grid infrastructure and therefore in smaller grid tariffs for the customers.

Finally, the geographical situation and the existing heat market infrastructure of Denmark simplified the integration of distributed generation.

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