Norwegian Wind Power:

Levelized production costs and grid parity

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Preface

This thesis has been written during the first half of 2009. The purpose of this work has been to study the long-run marginal cost and grid parity for Norwegian wind power.

I would like to thank my supervisor Steinar Strøm for great advices and discussions.

Thanks to the Norwegian Wind Energy Association (NORWEA) for providing financial support and data. A special thanks to Secretary General Øyvind Isachsen for having confidence in me from day one.

I would also like to thank Trond Jensen at Statnett for his support on the BID-model (and of course the cycling conversations).

Thanks to Øistein Schmidt Galaaen for proof reading and feedback.

And finally, thank you May-Liss. We did it!

Errors and weaknesses in this thesis are the author’s responsibility.

Ben F. Bjørke

Oslo, August 2009

Table of contents

1. Introduction

Indeed, wind power is about to play a major role in the European transition to a more climate friendly production of energy, reducing the need for conventional energy production and the threat to energy security. During the last 20 years the wind power generated output has increased to more than 100 TWh from the small 0,7 TWh, most of it in countries like Denmark, Germany and Spain. But in several other countries the wind power development is ready for departure and among these countries we find Norway. In 2000, ten years after the enactment of the new Energy Act, which laid the legal foundation for the liberalization of the Norwegian electricity market, the target of 3 TWh annual production of wind energy by 2010 was launched. The ambitious target was accompanied by the establishment of the public company Enova, which responsibility was to ensure domestic wind energy investments and provide financing through the new Energy Fund.

For wind power, like all other new renewable energy sources, the long-run marginal cost exceeds the market price. In a liberalized competitive market we would expect to see investments if and only if the long-run marginal cost equated the market price. In other words, we should not expect any new investments in wind energy as long as the competitive market principle is not fulfilled. However, the rapid development of wind power and the establishment of public financial institutions like Enova underscore the political will to subsidize the wind industry. Given that society finds it important to invest in wind power, it is important to acquire knowledge about the magnitude of the subsidy in the future. Even though society chooses to support wind power financially, it is in society's best interest to minimize the subsidy. The main purpose of this thesis is to study the grid parity of Norwegian wind power. Grid parity is defined as the point at which the cost of electricity from wind power will equal the cost of producing electricity by traditional means without taking into consideration subsidies. For a technology to reach its grid parity either the market price must increase or the long-run marginal cost decrease. By estimating future energy prices, information about the future price development can be obtained. By identifying the cost components and estimate their value, calculation of the long-run marginal cost is obtained. Comparison of the two will provide information on whether or not Norwegian wind power will reach its grid parity, hence, if there will a need for subsidies in the future.

The wind power industry is capital intensive, as much as 75 to 80 percent of the total cost is related to upfront capital costs while the operation and maintenance cost attribute to the remaining 20 to 25 percent. Further, the wind turbine cost attributes to approximately 70-80 percent of the total capital cost, which means that any future cost decrease in large part must come from the turbine producers or more efficient turbines. The information from the capital and operational and maintenance cost breakdown has been used to calculate the long-run marginal cost for 12 of the Norwegian wind farms which have gotten their application for concession approved by the energy authorities. The long-run marginal cost, also referred to as the levelized production cost (LPC), is calculated in range between approximately 0,5 NOK/kWh and 0,7 NOK/kWh with a discount rate of 6 percent. In order to estimate the future price development, a scenario for 2025 has been developed. The future price is estimated by the use of the BID-model for Norway and the neighboring trade partners, and is for Norway reported at an average NOK 0,33.

It then remains to see whether or not it is reasonable to expect the cost of wind power to decrease. Studies of experience curves show that the turbine price is expected to decrease between 2 to 8 percent when the cumulative production doubles (Neij et al., 2003).

The rest of the thesis is organized as follows: In Chapter 2, a brief review on how wind power entered the Norwegian political agenda is provided. Chapter 3 describes the policies for promoting the development of wind power, with emphasis on the Norwegian model for subsidies. Chapter 4 describes the development of wind power and other energy sources in EU27 and Norway. In Chapter 5 an equilibrium model with hydro power and wind power is presented, as well as cost calculation methodology. Chapter 6 describes the components of the costs related to wind power and calculates the levelized production costs for 12 Norwegian wind farms. The discount rate and the annual energy output have a major impact on the level of the LPC, and the chapter provides a thorough discussion on the two factors. Chapter 7 uses scenario methodology to estimate future electricity market prices for five of the Norwegians price regions and the neighboring trade partners (reported in the Appendix). Chapter 8 establishes a Salter-diagram which illustrates that the Norwegian wind power industry has yet to reach its grid parity. It also briefly discusses the future development of wind power costs. Chapter 9 concludes the thesis.

2. Renewable energy: How the focus emerged

The main purpose of this chapter is to provide an overview of how the focus on new renewable energy in Norway emerged. The chapter looks at the regulation period – the time period from the 1950s to the end of the 1980s, and the deregulation of the Norwegian energy market through the introduction of the Energy Act of 1990. The chapter then briefly considers some environmental issues in regard to wind power.

2.1 The regulation period

The Energy Act of 1990 laid the legal foundations for the Norwegian energy market reform. The main motivation for the reform was an increasing dissatisfaction with the performance of the sector in terms of economic efficiency in resource utilization, particularly in regard to investment behavior, which caused capacity to exceed demand (Bye & Hope, 2005). To reach the socially optimal development of power plants, the plants should be ranked according to their long run marginal costs and no projects should be developed before the long run marginal cost equated the market price.

Historically, there has been no direct link between market prices and investment. During the regulation period, all investments in production and transmission capacity were subject to cost reimbursement. In the years before 1979 government equated average costs to prices. Investment decisions were based on energy prognoses provided by the government and in principle any increase in demand should be covered by increasing supply. This led to overinvestment in power production.

In 1979 a new pricing rule was implemented. Now the investment decisions should be based on the long run marginal cost principle (see Chapter 5). In a free market the marginal cost principle says that investment can take place when the price equals long run marginal costs. However, during the 1980s prices were still regulated by the government. The government used the long run marginal cost as a price criterion rather than an investment decision rule. The result was inefficient utilities and output maximization to ensure adequate supply. In addition different prices were set for different consumers, which led to inefficiencies and welfare losses. Bye & Hope (2005) points to Midttun (1987) to outline the political discussion on investment and pricing in Norway during the 1960s to 1980s. Midttun's conclusions include the following: (i) Production capacity in state-owned companies had not increased following increases in marginal costs. (ii) The power price had never been high enough to cover the marginal cost of expansion. (iii) The expansion of capacity had led to excessive investments. After 1979, when the investment rule of equating prices to marginal costs was introduced, politicians wanted to lower the discount rate on investment projects to secure lower prices.

It is obvious that throughout the whole regulation period, politicians tried to avoid higher electricity prices. They wanted to keep prices stable and planned investment from a goal of having stable prices. Inefficiencies in transmission and distribution and inefficiencies in the market were other market imperfections that were identified during the regulation period, see Bye & Hope (2005, p.7–8) and Bye & Halvorsen (1998).

2.2 Liberalization of the energy market

A full opening of the Norwegian electricity market was carried out through the introduction of Act no. 50 of 29 June 1990: Act relating to the generation, conversion, transmission, trading, distribution and use of energy etc. The purpose of the act is given in Section 1-2: The Act shall ensure that the generation, conversion, transmission, trading, distribution and use of energy are conducted in a way that efficiently promotes the interests of society, which includes taking into consideration any public and private interests that will be affected. Bye & Hope (2005) highlights the main elements of the Norwegian electricity market reform:

- The market was designed to be a regular spot market incorporating demand. The market was immediately open to all potential buyers, including households.
- Common carriage principles requiring access to the network system on a transparent and nondiscriminatory basis facilitated market-based trade.
- The state-owned giant Statkraft was split vertically into two separate legal entities: The generating company, Statkraft SF, and the transmission company, Statnett SF. Other vertical integrated companies were split into generating or trading divisions and network divisions.
- The network companies were subject to natural monopoly regulations designed to achieve economic efficiency in network operations. In 1997, income frame regulations were introduced instead.
- Privatization of the power sector was politically unacceptable. Therefore the market liberalization reform was implemented without changes in ownership.

The deregulation of the market was expected to lower investment, reduce and equalize prices between consumers, lower net tariffs, and raise the rate of return on investment.

During the regulation period the public attempted to equate prices to long-run marginal costs. Theoretically, long-run prices should then reflect long-run marginal costs, and excess capacity should not be possible. However, during the regulation period excess capacity was the case. One of the reasons was that the energy-intensive industries paid prices corresponding to 25 percent to 33 percent of the long-run marginal costs. Prices were set to match the energy-intensive industry's competitiveness and not from the alternative value in the market. Another reason was that excess production in relation to domestic demand was sold on the international market in the form of occasional power at low prices. The producers could then keep prices relatively high in the domestic market and sell the excess production on the international market. A third reason for excess capacity was the spilling of up to five per cent of the inflows during the periods of spring melting and fall rains. A fourth argument was that there did not exist a ranking of the not-developed projects. Finally, when the new marginal cost pricing rule was introduced in 1979, the electricity tax was included in the long-run price. Hence, the long-run prices were in fact lower than faced by the investors.

Due to the deregulation of the Norwegian electricity market, previously excess capacity competes in the market. When excess capacity competes in the market, electricity prices are below long-run marginal costs in the short and medium run. This persists until demand increases and production capacity constrains growth. Then prices increase again and stimulate further investment. The deregulation also put a downward pressure on prices by generating an expected efficiency gain in terms of operating costs and investment costs. Finally, it led to price equality between consumers.

During the regulation period and the first six years after the 1991-deregulation, Norway was a net exporter of electricity. But investments in new production had already started to decline in the early 1980s. This was mainly because of a sharp increase in the marginal cost of expansion and environmental concerns (Bye and Hope, 2005). After deregulation, investment continued to fall. On the other hand, demand increased, Norwegian capacity was restricted and prices increased. In his new year's speech in 2001, the Norwegian prime minister outlined that new investments in large hydro power is over. Since then politicians have seemed unanimous in the blocking of new investments in hydro, nuclear and other thermal plant technologies. The only feasible alternatives seem to be new renewable technologies like solar, biomass, wave, and on- and offshore wind energy.

2.3 New renewable energy

Ten years after the introduction of the Energy Act, energy economization and new renewable energy entered the political agenda. Concerns regarding the security of supply and environmental issues were the main motivations. In the Norwegian economy approximately 99 per cent of the electricity production is produced by hydro power, which means that the electricity prices are volatile to dry or wet seasons. At the same time, due to environmental issues, the government wanted other production alternatives than fossil fuels and hydro power. This is underscored in the Proposition to the Odelsting nr. 35 (2000-2001):

> The main target for the energy policy is to maintain an effective and secure supply of energy…The government's objective is to be ahead of the market development. Measures on energy economization, the less use of energy in heating and new renewable energy production, shall contribute to future solutions in the case of energy.[1]

The proposition also sets the targets for energy production from renewable energy, inclusive wind power:

> The targets for the restructuring of the energy sector are…the production of 3 TWh from wind power by the year 2010.[1]

The author has not been able to find good explanations behind the 3-TWh-target. However, it is claimed that 3 TWh was what was considered to be within the reach with the existing support mechanisms.

The Norwegian Water and Energy Directorate (NVE) has the responsibility for the formal concession process on investments in new energy projects and the grid. The proposition claims that there is a conflict of interest between the maximization of the general public interest, which is the NVE's main purpose in regard to the concessions, and the introduction of new renewable energy. Since the development of wind energy projects takes several years, the Ministry of Oil and Energy claims that problems could occur in the transferring of money between annual budgets. They conclude that this activity should be outsourced from the NVE. In Recommendation nr.122 to the Storting (1999-2000) the majority voted for an independent institution:

[1] Author's translation.

> The majority points out that the NVE should be relieved from the task of coordination and clarification in regard to supporting…energy production. On this background the majority proposes the establishment of a new state-owned company…The (company's) objective should be to reach the targets set within electricity economization, the transition from electricity to heat, and wind power.[2]

This provides the fundament for the establishment of the state-owned company Enova SF, which was established in 2001. Through Recommendation nr.59 to the Odelsting (2000-2001), Enova's mandate was to coordinate the reformation of energy usage and design a new financing model suited for the introduction of wind power and other renewable energy sources. Enova SF was also handed the responsibility for a new energy fund, established January 2002, and to increase the production of energy from wind power with 3 TWh, starting in 2000. The regulation responsibilities for the Energy Fund were handed to the Ministry of Oil and Energy. The fund should support and ensure that assets were used in a productive way as possible for providing predictable financial support in the advantage of investments in renewable energy. The fund was financed through the grid tariff, which at the date of establishment was 0,3 Nøre/kWh. From July 2004 the tariff increased to 1 Nøre/kWh, which implies approximately an annual tax increase of NOK 200 for a household that consumes 20000 kWh per year[3]. The Energy Fund also finances the operational cost for Enova SF.

2.4 Environmental issues

Besides energy supply issues, the environmental concerns have been the primary argument for the investment in, and transition into, low carbonized energy production. One of the major papers on the environmental issue is the Stern Review on the Economics of Climate Change released in October 2006. Although not the first economic report on climate change and global warming, it is significant as the largest and most widely known and discussed of its kind. According to Stern (2006) climate change is the greatest and widest-ranging market failure ever seen. To be able to cope with the increasing emissions of CO_2 the power sector around the world will have to be at least 60 percent, and perhaps as much as 75 percent, decarbonised by 2050 to stabilize at or below 550ppm CO_2e[4]. Three elements of policy for mitigation are essential: A carbon price, technology policy, and the removal of barriers to behavioral change.

[2] Author's translation.
[3] The Norwegian average electricity consumption is 20000 kWh per year.
[4] Carbon Dioxide Equivalence (CO_2e) is a quantity that describes, for a given Greenhouse Gas, the amount of CO_2 that would have the same global warming potential, when measured over a specified timescale (generally, 100 years).

While many of the technologies to achieve this already exist, such as wind power, the priority must be to bring down their cost so that they can compete with fossil-fuel alternatives under a carbon-pricing policy regime (Stern, 2006). The social cost of carbon is likely to increase steadily over time because marginal damages increase with the stock of green house gases in the atmosphere, and that stock rises over time. This should foster the development of technology that can drive down the average cost of abatement. However, pricing carbon, by itself, will not be sufficient to bring forth all the necessary innovation, particularly in the early years. The development and deployment of a wide range of low-carbon technologies is essential in achieving the deep cuts in emissions that are needed. Experience shows that costs of technologies fall with scale and experience. Carbon pricing gives an incentive to invest in new technologies to reduce carbon. Indeed, without it, there is little reason to make such investments. But investing in new lower-carbon technologies involves risk. Companies may worry that they will not have a market for their new product if carbon-pricing policy is not maintained into the future. And the knowledge gained from research and development is a public good; companies may under-invest in projects with a big social payoff if they fear they will be unable to capture the full benefits. Thus there are good economic reasons to promote new technology directly. Policies to support the market for early-stage technologies will be critical. Different support schemes for the promotion of renewable energy will be discussed in Chapter 3. The investments made in the next 10-20 years could lock in very high emissions for the next half-century, or present an opportunity to move the world onto a sustainable path. Calculations based on income, historic responsibility and per capita emissions all point to rich countries taking responsibility for emissions reductions of 60-80 percent from 1990 levels to 2050.

Markets for low-carbon energy products are likely to be worth at least $500bn per year by 2050, and perhaps much more. According to the Stern-review (2006), individual companies and countries should position themselves to take advantage of these opportunities.

3. Policies for promoting the development of wind power

Due to high fixed costs, low running costs and a fairly long lifetime, economics of wind turbines have not yet reach its grid parity. Hence, wind power is highly dependent on stable and long-term agreed payments for the turbine's electricity production. Characteristic for the three top wind energy producing countries, Germany, Spain and Denmark, is that they have introduced long-term agreements on fixed feed-in tariffs, and that these feed-in tariffs are fixed at relatively high levels. It seems like the introduction of the standard payment schemes has had a significant influence on the wind turbine development in these countries (Morthorst, 1999a). Denmark, Germany and Spain together cover more than 80 percent of the total European wind energy capacity. Norway, on the other hand, was part of green certificate regime with Holland until the beginning of 2003, when Holland withdrew from the agreement. Then Norway introduced a competitive bidding incentive scheme, which in terms of absolute capacity growth has proved less effective (Menanteau et al., 2003).

During the past few years, a number of different policy instruments have been used to promote the development of wind power. In addition to carbon and energy taxes on the production from conventional energy supply technologies, these instruments or support schemes fall into three main categories that are either price-based or quantity-based:

- Feed-in tariffs, used particular in Germany, Spain and Denmark.
- Bidding processes, such as the one used in Norway.
- Tradable green certificates schemes, where electricity suppliers are obliged to produce or distribute renewable energy. This type of instrument is used in Sweden, but could eventually be extended to all European countries (Menanteau et al., 2003).

This chapter deals with the three incentive schemes, though with a more thorough description of the Norwegian model.

3.1 A closer look at the Norwegian model

One of the objectives of the establishment of Enova was to establish a more cost effective approach to new renewable energy. In order to decide which wind power plant to receive support, Enova ranks the different projects according to energy results, defined as NOK/kWh, the projects economical lifetime and the target of 3 TWh wind power by 2010. Generally projects with low costs relative to generated effect will by definition be competitive by themselves and not receive payments from the Energy Fund.

In 2002 Enova released its investment support scheme for wind power. In addition a program for the benefit of research on wind power was introduced. The investment support scheme provides a maximum of 20Nøre/kWh per year, limited to a maximum of ten per cent of approved investment costs set to max six million NOK per MW installed capacity.

The Enova support shall not over-compensate the wind projects. The policy shall trigger investments, which means that the project would not be started without the support from Enova. The term over-compensation means that the project shall not receive a larger relative economical support than what is needed in order to construct the wind farm. The investment support is based on the project's net present value analysis, including the project's expected rate of return or discount rate. Enova bases its decision on the following factors:

- A discount rate of 8 percent.
- The lifetime, given as construction time plus 20 years of production.
- Electricity prices, based on the six monthly three years forward on the Nord Pool given at the date of appliance.
- Income, calculated from the electricity price multiplied by expected production.
- Exchange rate at the date of appliance.

In addition the project must provide a climate report, including documentation on all environmental implications, a tentative offer from the turbine company, including total costs and type of turbine, a statement from the grid company on excess grid capacity and a project description which includes capital investment costs, operating costs, tentative financial plan and a plan of progress. The projects are then evaluated from two main criteria: (i) The projects financial plan and the size of needed economical support and (ii) project costs in relation to the energy result (kWh).

A new model for financing the Energy Fund was introduced in 2004. From being financed through the national budget, the new model introduced a mark up on the grid tariff. This mark up was set to 1Nøre/kWh, which provides the Energy Fund with approximately 650 million Norwegian kroner per year.

Enova is obliged to document the achievements and does that through the release of a yearly report. In 2003 the contracted wind power result was 450 GWh and the total support value NOK 92 million. In 2004 the 1023 GWh wind power was contracted upon, and the total support value was NOK 384 million. I 2005 the reported level of production for 2004 fell to

650 GWh, while the contracted wind power capacity for 2005 was 585 GWh. The reported value for 2003 in 2005 fell to 124 GWh. In 2006 no support to wind power was given. In 2007 NOK 218 million subsidized 260 GWh of wind power capacity. I 2008 wind power was subsidized with NOK 445 million, with an estimated production of 276 GWH. In 2009 the results for 2008 were changed to NOK 93 million and 65 GWh. Obviously the energy results differ from year to year. The projects given support at a given date are not obliged to start construction and have the right to reject the support and reapply at a later date. Usually the reason for rejection has been that the projects have disagreed in the amount of support given. In 2006 no support was given due to uncertainty regarding future support schemes. At that time Sweden and Norway discussed the possibility of a mutual Norwegian-Swedish green certificate market. The Norwegian government concluded that a common certificate market would become too expensive for the Norwegian consumers and industry and wanted instead to improve the already established instruments.

Project	Owner	District	Support mill.NOK	GWh	Year	Status
Smøla	Statkraft Energi AS	Smøla	72	120	2001	In operation
Sandhaugen	Norsk Miljøkraft AS	Tromsø	2,9	4	2003	In operation
Nygårdsfjellet	Narvik Energi AS	Narvik	4,2	24	2003	In operation
Hundhammerfjellet	Nord-Trøndelag Elektrisitetsverk	Nærøy	35	10	2003	In operation
Hitra	Hitra Vind AS	Hitra	33,2	155	2003	In operation
Smøla	Statkraft Energi AS	Smøla	66,6	330	2003	In operation
Hundhammerfjellet	NTE	Nærøy	65	150	2004	In operation
Valsneset	Trønderenergi Kraft	Bjugn	30,7	35	2004	In operation
Bessakerfjellet	Trønderenergi Kraft	Roan	100	155	2005	In operation
Gartefjellet	Kjøllefjord Vind AS	Lebesby	86	150	2007	In operation
Mehuken 2	Kvalheim Kraft	Vågsøy	93	65	2008	Under construction
Høg Jæren	Jæren Energi	Time og Hå	511,6	200	2009	Contracted
Fakken	Troms Kraft	Karlsøy	346,4	200	2009	Contracted
Hundhammerfjellet 2	NTE	Nærøy	16,4	10	2009	Contracted
Nygårdsfjellet 2	Nordkraft Vind	Narvik	200,1	123	2009	Contracted
Sum			**1663,1**	**1731**		

Table 3.1: Wind energy results 2001-2009 (Source: Enova).

Table 3.1 sums up the wind energy results for the period 2001-2009. Only projects in operation, under construction or under contract with Enova are enlisted. During the period

2001-2009 a total of 1731 GWh of wind power have received support, with the total value of NOK 1663 million. In summary, the amount paid per GWh is approximately NOK 1 million.

3.2 Support schemes to renewable energy

The following sections describe the incentive schemes most used within the European energy market.

3.2.1 Green certificates

The main characteristics of a green certificate market are the following: All consumers are obliged to buy a certain share of their total electricity consumption from renewable energy technologies. All renewable energy technologies, including wind power, biomass and biogas plants, photovoltaics, wave power, geothermal and small hydro plants, will be certified for producing green electricity[5]. Per unit (kWh) of electricity produced they will receive a green certificate, which can be sold to distribution companies or other electricity consumers with the obligation to cover a share of their electricity consumption with green power. The market will function solely as a financial one restricted only by the upper limit of green certificates, which cannot exceed the amount of electricity produced by the renewable technologies.

3.2.2 Feed-in tariffs

The feed-in tariff scheme involves an obligation on the part of electric utilities to purchase the electricity produced by renewable energy producers in their service area at a tariff determined by the public authorities and guaranteed for å specific period (Menateau et al., 2003). The electricity that is generated is bought by the utility above market price. For example, if the market price for electricity is 0,35 NOK/kWh, then the rate for green power might be 0,8 NOK/kWh. The difference is spread over all the customers of the utility. If NOK 10000 worth of green power is bought in a year by a utility that has 500000 customers, then for each customer NOK 0,02 per kWh is added to the electrical bill annually. In a feed-in tariff system the producers of renewable energy (i.e. wind power) are encouraged to exploit all available generating sites until the marginal cost of producing wind power equals the feed in tariff. If the feed in tariff is set to p_{in}, the amount then generated corresponds to q_{out} (see Fig. 3.1). Generally, the long-run marginal cost curve is not known, hence the amount generated is uncertain a priori.

[5] The definition of renewable energy is based on the Swedish Proposition to parliament 2002/02:40 (see Flagstad et al., 2004, p. 15).

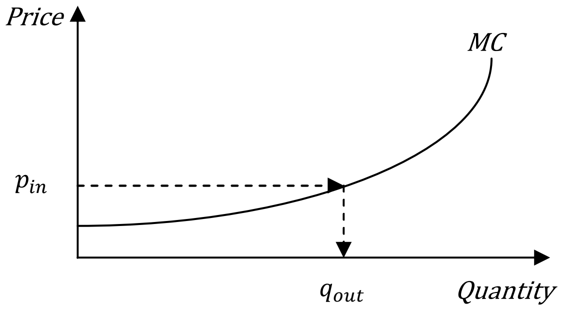

Fig. 3.1: Feed-in tariff (Source: Menanteau et al., 2003).

All projects with a long-run marginal cost less or equal to the tariff will benefit from this kind of incentive regime. The difference in quality of various sites leads to the attribution of a differential rent, to the advantage of those projects with the lowest production costs. The overall costs of reaching the objective is given by the area $p_{in} \times q_{out}$. From Figure 3.1 we see that the higher the feed-in tariff, the higher the quantity of wind power generated, and of course the higher the total cost.

3.2.3 Competitive bidding process

Through the competitive bidding processes, the regulator defines a target for the amount of renewable energy to be faced in, and organizes a competition between renewable producers to reach this target. This instrument has been in use in Norway since the establishment of Enova in 2001, but it has also been applied in the UK and France. The competition focuses on price per kWh and through their bids the competitors reveal their long-run marginal cost curves (ex post). It is Enova's, or the respective countries energy authority's, task to classify the bids in increased order until the amount to be contracted is reached.

The amount to be reached is q_{in} (Fig. 3.2). The marginal cost, p_{out}, is the price for the last unit of wind power that enables the target to be reached. The implicit subsidies attributed to each generator correspond to the difference between the bid price and the wholesale market price. In the competitive bidding system the exact amount of wind power concerned by the bids is a priori known. However, the marginal cost curves are not known a priori, hence the total cost of reaching the target cannot be determined. Theoretically, the overall costs of reaching the target is given by the area situated under the marginal cost curve. Compared to feed-in tariffs the differential rent paid to renewable energy generators, does not have to be borne by the consumers over the electricity bill. It is worth noting that in the Norwegian regime a tariff of 1 Nøre is added to the electricity bill in order to contribute to the so called renewable energy fund controlled by Enova.

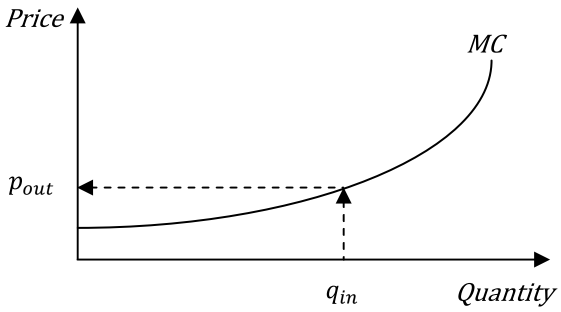

Fig. 3.2: The Competitive bidding process (Source: Menanteau et al., 2003).

4. The European power sector

All though the total gross energy generation in Europe (EU27) has grown with 30 percent during the last 20 years, the composition of the power output has changed. Especially, there has been a transition from oil-fired power plants to natural gas-fired plants, and renewable energy has started to play a more important role in the energy composition.

This section investigates the capacity development in the European energy sector for the period 1990 to 2007. First it looks at the composition of the power output and how this composition has developed during the time period. Then it focuses on the development of wind power production. The development within the largest European wind generation countries will be discussed and the driving forces behind this development will be described. Norwegian electricity generation will also be discussed and the development of wind power in Norway will be described.

4.1 The development of wind power in the EU and Norway

As expected the total gross generation of electricity in the EU has increased at an average annual growth rate of 1,5 percent (see Table 4.1) to 3362 TWh in 2007 from 2854 TWh in 1990. For the whole time period the increase in electricity generation has been 30 percent.

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
TWh	2584	2628	2617	2617	2655	2733	2830	2841	2910	2940	3021	3108	3117	3216	3288	3309	3354	3362
%	-	1,7	-0,4	0,0	1,5	2,9	3,5	0,4	2,4	1,0	2,8	2,9	0,3	3,2	2,2	0,6	1,4	0,2

Table 4.1: Total annual gross electricity generation and annual growth rate for EU27 (Source: Eurostat).

The European power output is composited by power plants mainly run by ten different energy sources; Nuclear, coal- and lignite, natural and derived gas, oil, hydro, wind, biomass and geothermal power. In addition there are some smaller energy sources like photovoltaic in the composition. Nuclear-fired and coal- and lignite-fired power plants have contributed to almost half of the total production for the whole time period. The generation from hydro power has been stable around ten percent of the total gross generation.

There are two changes during the time period that needs a closer look. Firstly, there has been a remarkable decrease in the use of oil-fired power plants. At the same time the use of natural gas in the generation of electricity has almost tripled in size. This trend is related to a large transition from oil to gas in countries like Italy and the UK. Italy has reduced its dependence on oil-fired electricity generation with 65 percent, while the reduction in the UK has been more than 85 percent. At the same time, Italy has increased the power output from natural gas from 50 TWh to 172 TWh, while there has been a considerably larger increase in the UK to 164 TWh from the small 3 Twh in 1990. Secondly, the development of renewable energy, and especially wind power, has played an important role. The European wind power capacity has increased to 104 TWh in 2007 from 0,7 TWh in 1990. Compared to the growth rate of other energy sources, wind power is by far the energy source with the largest relative growth rate. Wind power now constitutes more than three percent of total gross electricity generation in Europe. Figure 4.1 shows the annual total gross electricity generation by energy sources and Figure 4.2 shows the changes in the power output composition by energy sources.

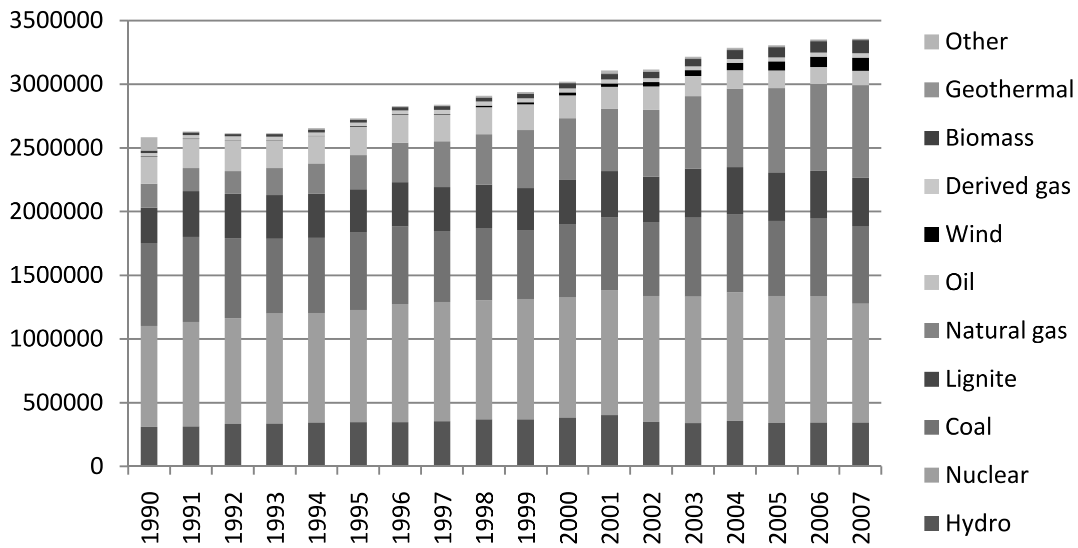

Fig. 4.1: Total gross electricity generation divided into the specific energy sources (Source: Eurostat).

The power supply in Norway is primarily from hydroelectric power plants. Of the total production in 2007 of 137 TWh, 135 TWh was from hydroelectric plants, 900 GWh was wind generated, 730 GWh was generated by natural-gas fired power plants, 432 GWh was from biomass. The Norwegian electricity generation varies due to dry and wet seasons. 1996 was a record low with only a generation of 103 TWh, while the record high was 142 TWh in 2000. Figure 4.3 shows the development of the energy output composition for the three sources with the largest growth in the Norwegian electricity market. As shown, wind power has had a rapid development since 2002, which is related to the establishment of Enova as mentioned above. Natural gas-fired electricity generation also grew at a fast pace due to the construction of the natural gas power plant in Kårstø. In addition biomass-fired power plants have become a new source in the energy mix.

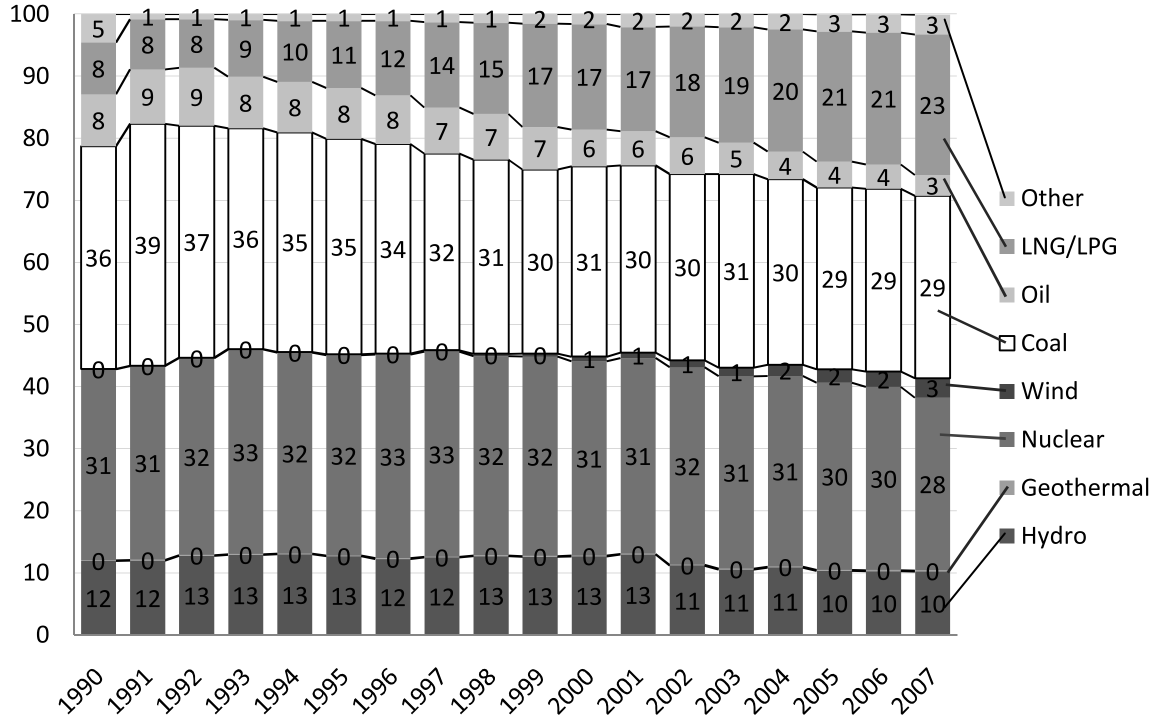

Fig. 4.2: Changes in power output composition by energy sources for EU27 1990-2007 (Source: Eurostat).

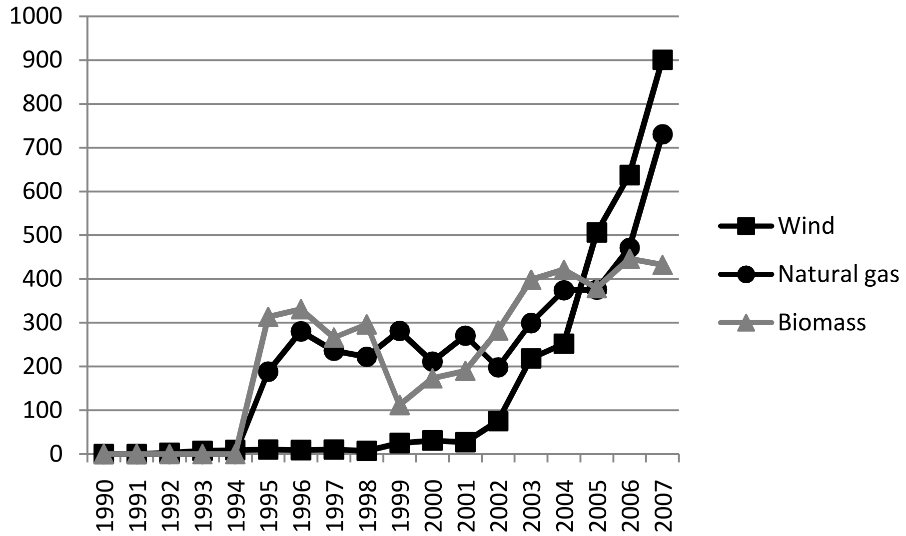

Fig. 4.3: Changes in power output from wind energy, natural gas and biomass for Norway 1990-2007 (Source: Eurostat).

4.2. Capacity Development of wind turbines in Europe and Norway

In the recent years wind power in the EU has developed at a rapid pace with an average capacity increase of 34 percent per year in the time period 1990 to 2007. The end of 2007 statistics on European accumulated wind power production shows a total installed volume of 104259 GWh. The installed wind power capacity was more than 75 times higher in 2008 than

1990. The main part of the capacity growth has been related to relatively few countries, namely Denmark, Germany and Spain. Figure 4.4 shows the capacity development in these three countries, which together covered more than 71 percent of the total European wind turbine capacity in 2007. As shown in Figure 4.4, Germany in particular has had a rapid development. In 1991 the total accumulated generation in Germany was approximately 215 GWh. By 2007 the average annual increase in production was approximately 2 TWh and the total installed wind power production capacity was above 39 TWh. Similar trends are found in Denmark and Spain, although not to the same extent. By the end of 2007 the total output from wind turbines in Spain was more than 29 TWh and above 7 TWh in Denmark.

During the past few years a number of different policy instruments have been used to promote the development of wind power. Among these can be mentioned: investment and production subsidies, power purchase agreements, tax credits for different ownership and carbon and energy taxes on the production from conventional energy supply technologies (Morthorst, 1999a). According to Morthorst (2000) the feed-in tariffs have made it highly profitable to establish new wind turbines in Denmark.

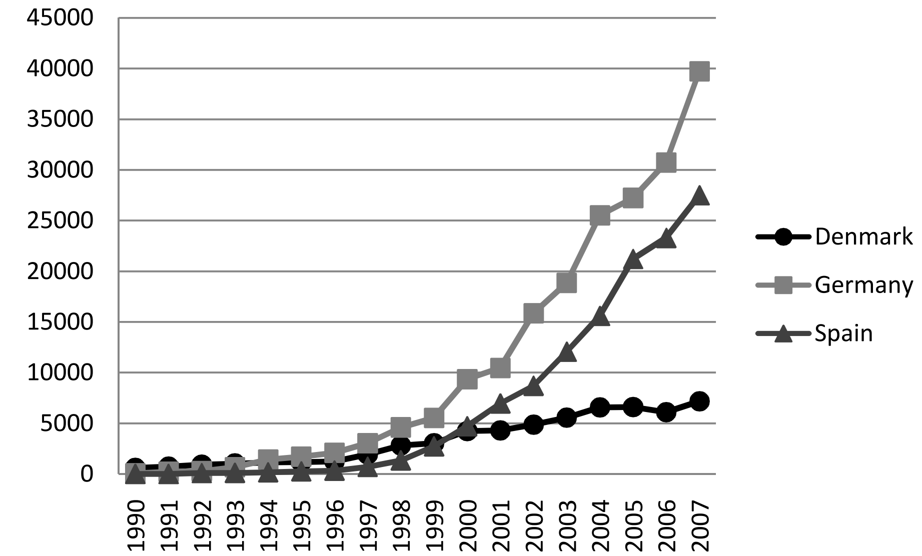

Fig. 4.4: Annual wind turbine capacity development in Germany, Denmark and Spain (Source: Eurostat).

Wind turbines are highly dependent on stable and long-term agreed payments for the turbine's electricity production and this is related to the political willingness to introduce and retain such standard payment schemes (Morthorst, 1999a). Characteristic for the three above-mentioned countries is that they have introduced some kinds of long-term agreements on fixed feed-in tariffs, and that these feed-in tariffs are fixed at fairly high levels. Germany started a feed-in regime in 1989 and Spain followed suit in 1994. Both countries have the same basic model. Via renewable energies acts (Erneuberbare-Energien-Gesetz (EEG) in Germany and the Real Decreto in Spain) that guarantee grid access for electricity from renewable energy generation systems and that provide long-term compensation framework (Ragwitz et al, 2005). Both the EEG and the Real Decreto support a broad portfolio of renewable electricity technologies and orient compensation to the costs of generating electricity with the various relevant technologies. Additional expenditures for additional compensation are distributed among electricity consumers in accordance with consumers' consumption. Nonetheless, the two energy acts differ in a number of ways. Compensation in Spain is oriented to the development of average electricity price, while in Germany fixed compensation levels, defined for each year in question, are guaranteed. Furthermore, plant operators in Spain may choose between (i) fixed compensation of about 6,5 €cents/kWh (2004-values) or (ii) a bonus of about 3,6 cents/kWh in addition to the agreed electricity price on the open market. Finally, compensation depends on regulated electricity rates. Theoretically this should reduce investment security (Ragwitz et al, 2005), but since annually defined rates have not changed in the past years, and since such changes are not expected in the future, this arrangement has not had any negative impact on the development of the Spanish electricity market.

In Germany feed-in rates are oriented more strongly to actual generation costs. When it comes to wind energy, sites with less wind capacity get better rates than sites with higher wind capcacity. The EEG also provides greater differentiation with regard to plant sizes. For nearly all renewable energies, compensation follows a chronological digression. For example, would photovoltaic systems installed on buildings in 2005 receive a compensation for a 20-year period, of 57,4 cents per produced kWh, plants built a year later would receive 5 percent less compensation over 20 years.

The Danish Government provides a subsidy to wind turbines, corresponding partly to an effective refund of the energy and environmental taxes that are levied on the private consumption of electricity (Morthorst, 1999a). In Denmark the long-term agreement on fixed feed-in tariffs was introduced in 1984.

Inspection of Figure 4.4 shows that the effect of the payment schemes had an immediate effect on wind turbine capacity development in Germany and Spain. In Denmark the take off in wind power investments were significant later.

The average annual growth in Norwegian wind power production has been more than 64 percent since 1992. Figure 4.5 shows the capacity growth for Norway. The dotted line indicates the 65 GWh of wind power capacity which received payments in 2008 and which is under construction and the capacity that has received payments for 2009. By inspecting Figure 4.5 it seems that the subsidy regime introduced in 2001 through the establishment of Enova SF and the Energy Fund has resulted in a relative large growth in wind power capacity in Norway (see Section 3.1 for a closer look at the Norwegian renewable energy policy). The reader would probably notice the discrepancy between the wind power output reported in Table 3.1 and the output reported in Figure 4.5. The former is based on the predicted electricity generation, while the latter is the actual generation reported by Eurostat. The discrepancy may be explained by several factors: (i) the wind measure methodology has not adjusted for the geographical surface and hence reported too optimistic results with regard to wind conditions, (ii) the lack of wind power experience has caused constructions of inefficient wind sites, and (iii) the technological development has been slower than expected, i.e. the growth in the turbine effect is less than first expected.

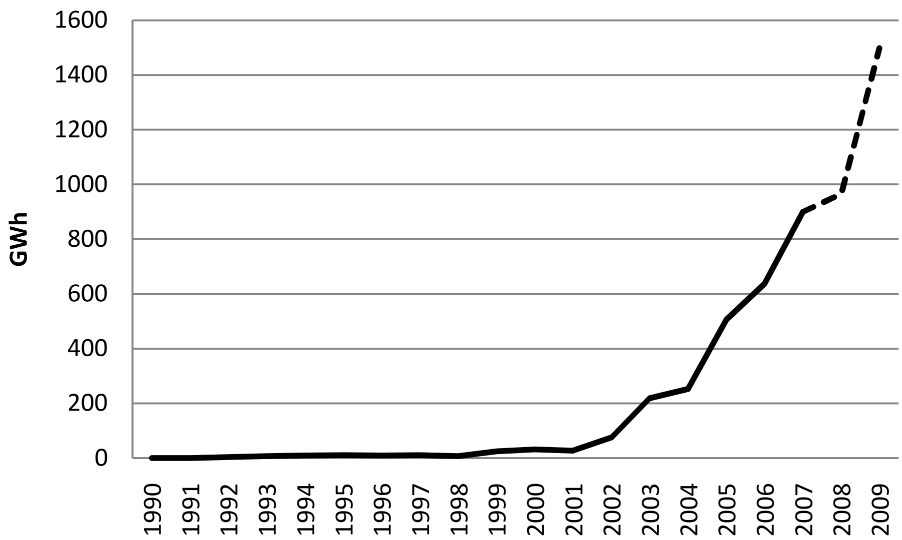

Fig. 4.5: Total accumulated wind power capacity for Norway 1990-2009 (Source: Eurostat and Enova).

In Figure 4.6, the wind power capacity development for the seven consecutive years after the introduction of a payment schemes in the three countries Denmark, Spain and Germany has been compared by indexation to capacity development in Norway after the establishment of Enova. Surprisingly, Norway has had the most rapid growth of the three countries. This could be due to technology learning, the fact that the technology is easier accessible or that the

Norwegian payment scheme is more effective than the schemes utilized in the three other countries. A further investigation is beyond the scope of this paper.

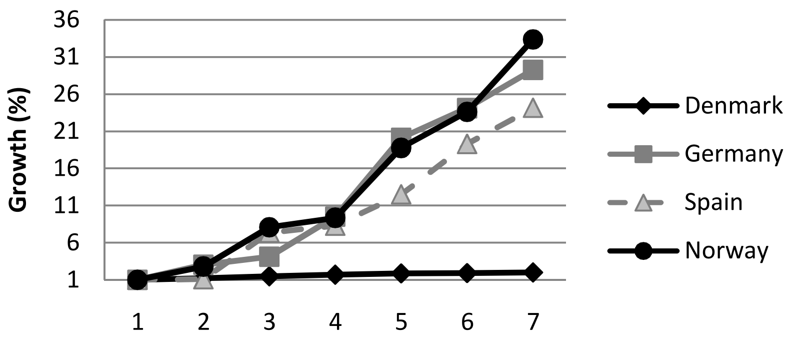

Fig. 4.6: Wind power development in Spain, Norway, Germany and Denmark (Index 1990=1 for Denmark, Germany and Spain. 2001=1 for Norway) (Source: Eurostat).

5. Modeling wind power in a closed economy

Electricity in the Nordic power market is traded on the Nord Pool. The Nord Pool's physical market establishes a balance between supply of and demand for electricity the following day. A well-functioning power market ensures that electricity is generated wherever the cost of generation is lowest at any time of the day. Increases in demand must be balanced against more expensive modes of generation. The market also gives indication of what it would take to establish new generating capacity, i.e. it indicates the level of the long-run marginal cost sufficient to increase wind power capacity. Through the Nord Pool market, every agent in the Nordic power market is a price taker, they cannot influence the price in any matter.

This chapter argues that in a perfect competitive market where all agents are price takers, economic efficiency is obtained by the maximization of the economy's total surplus. It establishes a simple model which shows that increases in wind power capacity is feasible when its long-run marginal cost equalizes the market price. The last section establishes the long-run cost methodology or the levelized production cost (LPC).

5.1 Competitive markets and economic efficiency

In chapter 2 we showed that the Norwegian electricity market has been liberalized through the Energy Act of 1990. Although, real world markets seldom achieve the ideals of the competitive market, the Norwegian electricity market fulfills some of the fundamental competitive market assumptions. In a competitive market each firm takes the price as being independent of its own actions and outside its control (Varian, 1992). Let p be the market price. Then the demand facing a competitive firm takes the form

$$D(p) = \begin{cases} 0 \; if \; p > \bar{p} \\ any \; amount \; if \; p = \bar{p} \\ \infty \; if \; p < \bar{p} \end{cases}$$

If a firm in a competitive market sets a price above the prevailing market price, no one will purchase its product. Since the firm in a competitive market must take the price as given, it must choose output x so as to solve

$$\max_x px - c(x).$$

The first order and second order conditions for an interior solution are

$$p = c'(x^*)$$

$$c''(x^*) \geq 0.$$

The term $c'(x^*)$ denotes the firm's marginal cost or long-run marginal cost. The long-run marginal cost is defined as the cost of providing an additional unit of commodity under assumption that this requires investment in capacity expansion. When dealing with wind power, assessing the long-run marginal cost function is the relevant approach to efficiency. We will soon return to the calculation of the long-run marginal cost function. The inverse supply function denoted by $p(x)$ measures the price that must prevail in order for a firm to find it profitable to supply a given amount of output. As long as the second order condition is fulfilled, the inverse demand function is given by

(1) $\quad p(x) = c'(x_i).$

The condition in (1) defines the competitive equilibrium. It is easy to see that in situations where the long-run marginal cost of a given firm is higher than the price, the firm will (should) not choose to produce positive levels of output.

To see how this can be used in a welfare analysis we turn for a moment to consider the representative consumer's choice. We will here assume that the utility function is quasilinear, on the form $x_0 + u(x_1)$ and that $u(x_1)$ is strictly concave. x_1 could here represent electricity in general. The maximization problem for the representative consumer, yields the following first order condition

(2) $\quad u'(x_i) = p,$

which requires that the marginal utility of the consumption of electricity to be equal to its price. In other words, (2) states that the marginal willingness to pay for electricity equals price. By combining equation (1) and (2), we see that the equilibrium level of output is given by the condition where as the willingness to pay for electricity equals its marginal cost of production

(3) $\quad u'(x_i) = c'(x_i).$

What does this result imply? Economic efficiency is characterized by a situation in which it is impossible to generate a larger welfare total from the available resources. In other words, a situation where some people cannot be made better off by the reallocation of resources, without making others worse off. In welfare analysis this situation occurs by maximization of the sum of the consumer's and producer's surplus

$$\max_{x} CS(x) + PS(x) = \max_{x}[u(x) - px] + [px - cx]$$

which yields the same result as (3). Any deviation from this equilibrium is by definition economically inefficient.

5.2 An equilibrium model with hydro and wind power

The following model is based on a similar model developed by professor Finn R. Førsund at the University of Oslo. We start out in a situation with no positive wind power production, no subsidizes and no climate policy. e is the total demand for electricity. e_{wa} is the total amount of electricity generated from hydroelectric power. e_{wi} is the total electricity generation by wind power. k_{wa} is capital in the production of hydro power. k_{wi} is capital in the production of wind power. q_k represents the price for capital and, finally, p is the market price. It is assumed that $e'_{wa} > 0$, $e''_{wa} \leq 0$, $e'_{wi} > 0$ and $e''_{wi} \leq 0$. The maximization problem is then given in (1)-(6).

(4) $\quad max_{k_{wa},k_{wi}}\, pe - q_k(k_{wa} + k_{wi})$

s.t.

(5) $\quad e = e_{wa} + e_{wi}$

(6) $\quad e_{wa} = e_{wa}(k_{wa})$

(7) $\quad e_{wi} = e_{wi}(k_{wi})$

(8) $\quad e_{wa} \geq 0$

(9) $\quad e_{wi} \geq 0$

The problem is here solved by the use of the Lagrangian

(10) $\quad L = p\big(e_{wa}(k_{wa}) + e_{wi}(k_{wi})\big) - q_k(k_{wa} + k_{wi}) - \lambda(e_{wa}(k_{wa}) + e_{wi}(k_{wi})),$

which gives the following first order conditions

(11) $\quad \frac{\delta L}{\delta k_{wa}} = 0 \Rightarrow pe'_{wa} - q_k - \lambda e'_{wa} = 0,$

(12) $\quad \frac{\delta L}{\delta k_{wi}} = 0 \Rightarrow pe'_{wi} - q_k - \lambda e'_{wi} = 0.$

For $e_{wi} = 0$, producers of hydroelectric power supply power up to the point where price equals marginal cost of producing hydro power, given by the equation

(13) $$p = \frac{q_k}{e'_{wa}}.$$

The facing in of wind power without subsidizing, $e_{wi} > 0$, may occur under the following condition

(14) $$\frac{q_k}{e'_{wa}} \geq \frac{q_k}{e'_{wi}}.$$

Equation (14) shows that the long-run marginal cost in the production of wind power should equal the long run marginal cost of hydroelectric power. Given positive production of hydro power and exogenous price, wind power could be faced into the electricity market if and only if the long-run marginal cost in the production of wind power is less or equal to the market price.

5.3 Cost calculation methodology

The cost of energy is expressed as the levelized production cost (LPC) (Tande et al., 1994), which is the cost of the production of one unit (kWh) levelized over the wind power station's entire lifetime. The LPC-methodology provides a detailed description on the calculation of the long-run marginal cost discussed in the previous section. As pointed out above, the application of the LPC is important when the costs of wind energy are compared with market price data and price forecasts. By comparing the LPC of the wind turbines with market price, an indication on the economic efficiency of wind power is provided. An LPC of the wind turbines lower or equal to the market power price indicates economic soundness for wind power. An LPC of wind turbines higher than the price indicates that the long-run costs of one unit of wind energy are higher than the market income for that unit, hence wind energy is economic inefficient. The LPC is also important when a choice is to be made between wind energy and other forms of energy systems. Based on cost efficiency, the system with the lowest LPC should be selected. The same applies to choices between wind energy sites and installation within a specific site.

Total net energy output and the total costs over the lifetime of the power station are both discounted at the start of operation by a predetermined discount rate, and the LPC is derived as the ratio of the discounted total cost (TC) and the annual net energy during year t (ANE_t).

In the calculations all costs are discounted to the present value. The LPC is given as

(15) $$LPC = \frac{TC}{\sum_{t=1}^{T} ANE_t (1+r)^{-t}},$$

where *n* is the number of years of economic lifetime and *TC* is the discounted present value of the total cost of energy production

(16) $$TC = I + \sum_{t=1}^{T}(OM_t + SC_t + RC_t)(1+r)^{-t} - SV(1+r)^{-n},$$

where I is the total investment costs[6], OM_t is the operation and maintenance costs during year *t*, SC_t is the social costs during year *t*, RC_t is the retrofit costs during year *t*, *SV* is the salvage value after *n* years and *r* is the discount rate.

The ANE_t is described as the annual potential energy output, E_{pot}, with a number of corrected factors

(17) $$ANE_t = E_{pot} \cdot K_{per} \cdot K_{site} \cdot K_{ava}.$$

K_{per} is the performance factor as a function of dirt, rain, ice, etc., K_{site} is the site factor as a function of obstacles and K_{ava} is the technical availability factor. The annual net energy output is further discussed in Section 6.3. For simplicity it is assumed that the annual net energy is to be constant from year to year, hence $ANE_t = ANE$. The *LPC* can then be reduced to

(18) $$LPC = I \cdot \frac{1}{R(r,T) \cdot ANE} + \frac{TOM}{R(r,T) \cdot ANE}$$

where *R(r,T)* is the annuity factor described as

(19) $$R(r,T) = \frac{1}{\sum_{t=1}^{T}(1+r)^{-T}},$$

and *TOM* is the total levelized annual «downline costs»

(20) $$TOM = R(r,T)^{-1} \cdot \sum_{t=1}^{T}(OM_t + SC_t + RC_t)(1+r)^{-t} - SV(1+r)^{-n}.$$

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[6] In cases where interest is paid during construction time, the interest payment should be calculated in the total investment: $I = \sum_{i=1}^{j} I_i (1+r)^{t_i}$, where *j* is the number of investment payments, *r* is discount rate and I_i is the investment part paid t_i years before the start of commercial operation of the wind power installment.

6. Costs of wind energy

This chapter focuses on the basic generation costs of a wind power plant, both upfront and variable costs. It describes the different cost factors and the magnitude of the different cost components relative to total costs. As the wind energy output and the discount rate have major impact on the long-run marginal costs for wind energy, these two topics are discussed in separate sections. Finally, the levelized production cost for 12 Norwegian wind farms is calculated.

6.1 Capital cost break down

Although only the total investment is included in the formula of the levelized production cost function (LPC), an analysis of wind power costs should include a breakdown of the project costs (Tande et al., 1994). A typical breakdown of the investment costs consists of the turbine supply agreement (TSA), infrastructure including civil and electrical works, substation, grid connection and project management (Bryars & Holt, 2008). Krohn et al. (2009) reports that the average turbine installed in Europe has had a total cost of around €1,23 million/MW. Further they report that on average 76 percent of the total cost, grid connection accounts for around 9 percent and foundation for around 7 percent. The total investment cost varies between countries, however, according to Krohn et al. (2009), IEA reports the total investment costs for Norway at a little more than €1200/kW. The variation is reported to be between €1000/kW to €1350/kW. Of other cost components, the main ones are grid connection and foundations. Other cost components like control systems, land, electric installations, consultants, financial costs, roads construction and control systems adds to the investment cost. Costs vary depending on turbine size, distance from grids, land ownership, the property tax level and the nature of the soil. Grid connection is the single most important cost component in addition to the turbine, followed by electrical cost and foundation cost. Krohn et al. (2009) reports the upfront investment cost's total share of total costs in Norwegian wind power projects to be close to 75 percent, while other costs amount to 25 percent. They claim that the turbine cost approximately €900/kW. As they point out, the rule of thumb for wind power capacity cost has been around €1000/kW. However, there have been great variations in the cost for wind power since 2000. From 2001 to 2004 the global market grew less than expected, with dramatic consequences for costs. For some projects costs were reported as low as €700/kW. In the period 2005-2008 the global market for wind power increased by 30-40 percent annually, and demand for wind turbines surged. Combined with increasing raw material prices up until mid-2008, the cost of wind power increased steadily.

First Securities AS, a Norwegian investment bank, estimated turbine prices between €3125000 and €3250000 in the first half of 2008. The European Commission assumes that onshore wind energy cost will drop to €826/kW in 2020 and €788/kW. This is consistent with First Securities AS, who regards the first half of 2008 a historic peak.

The costs of wind turbine installation include notably (Bryars et. al, 2008):

- Foundations
- Road constructions
- Underground cabling within the wind farm
- Low to medium voltage transformers
- Medium to high voltage substation
- Transport and craning
- Assembly and test
- Administrative, financing and legal costs

These cost elements typically amount for 16-32 percent of total investments in a wind project. The geography in terms of site accessibility and the geotechnical conditions on the site of the wind farm plays a crucial role in determining the cost of road construction and cabling. In Norway many wind projects must construct harbors for delivery of the turbines and there are even some projects that need to construct road tunnels in order to access the wind farms.

Table 6.1 sums up the total investment costs based on a 2,5 MW wind turbine.

	€ (mill.)	**NOK (mill. - 2008)**	**% of total**
TSA	3188	25334	70
Civil	501	3981	11
Electrical	228	1810	5
Development	319	2533	7
Contingency	228	1810	5
Transaction	91	724	2
Sum	**4554**	**36192**	100

Table 6.1: Total investment costs per megawatt.

6.1.1 Turbine supply agreement (TSA)

Up until 2000 growth in turbine size over time was a general industry trend (Krohn et al., 2009). In the 1980s the rotor diameter was between 20 to 40 meters. According to an ECON report (ECON, 1998) turbines of 500-600 kW capacity was the most economic efficient alternative for Norwegian wind farm projects in 1998. In 2000 the growth in turbine size had flattened out and the onshore supply is now dominated by turbines with a diameter of approximately 130 meters, which implies turbines in the range of 1,5 to 3 MW. The average turbine size in Norway in 2008 was 2,2 MW, while the average size of the ones installed in 2008 were 2,6 MW (Hofstad, 2009). In the UK and Germany the average installed size in 2007 was 2 MW and 1,8MW respectively. Turbines with capacities up to 2,5 MW are becoming increasingly important and made up a market share of 6 percent in 2007, compared to 0,3 percent at the end 2003. The average size of wind turbines installed in the EU has increased from 105kW in 1990 to 1,7MW in 2007.

In their assessment of the European wind market Bryars & Holt (2008) finds that the TSA typically amounts to 70 to 75 percent of total investment costs. Within the European market, the TSA costs include supply, delivery and installation of the wind turbines, inclusive initial warranty agreements. More specifically the costs includes the turbine (hub, nazelle, rotor and tower), transport, installation and commissioning. They also report a trend of rising cost and suggest a 26 percent increase in the price between 2005 and 2006 from €750 k/MW to €950k/MW and an 11 percent increase from €950 k/MW to €1050 k/MW between 2006 and 2007.

Based on the applications for concession to the NVE, wind turbines with 2MW to 5MW effect seems to be the most preferred alternative in Norwegian wind power projects. On the other hand, the industry itself reports that this has been highly based on a too optimistic belief in the technological development, and due to the Norwegian geographical conditions and the nature of the wind, we will see wind turbines with 2,3 MW to 2,5 MW effect as being the preferred alternative in the Norwegian wind industry. In real term prices for the first half of 2008 the price for the TSA, based on 2,5 MW wind turbines, was between €3125000 and €3250000 or between NOK 24680 million and NOK 25830 million. This gives a price per MW in the range between €1250 k/MW to €1300 k/MW, which is fairly consistent with Bryars & Holt’s result above.

6.1.2 Electrical costs

Electrical costs normally include turbine transformers, high voltage electrical between turbine transformers and substation and substation electrical equipment including switchgear and main transformers (Bryars et al., 2008). The cost for electrical cabling between the turbines within the wind farm and the cost for grid connection varies with the total number of turbines and the distance to the grid. Large wind farms are generally connected to the high voltage electrical transmission grid (60kV and above). In cases where a wind farm supplies more than 10 MW, high voltage connection is the proper alternative. In order to connect to the high voltage grid, the low voltage wind generated electricity must be transformed into high voltage by a transformer (22/132kV). Further, the actual electricity produced by the wind turbine itself, must be transformed to the right voltage on the internal grid within the wind farm. This transformer is relevant for every single wind turbine, hence, for every single wind turbine there is a transformer (0,69/22kV). The electrical costs also vary due to the location of the wind site, i.e. if the wind site is located at an island, the more expensive submarine cable could be necessary in order to connect to the grid.

Bryars & Holt (2008) reports electrical costs to an average €39 k/MW and the substation costs to an average €34 k/MW. Total electrical cost then amount to an average €73 k/MW. The electrical and substation costs both contribute to approximately four percent of the total investment cost.

6.1.3 Civil cost

As the case for electrical costs, the level of the internal and external road costs are dependent on the number of turbines in the wind farm, the distance to existing infrastructure, the geographical conditions and special requirements for construction of road tunnels, bridges and harbors. In addition, civil work costs includes turbine and transformer foundations, lay down areas, construction of buildings and crane pads.

According to Bryars & Holt (2008) the civil costs makes up an average of 11 percent of total investment costs or €96 k/MW.

6.1.4 Development and planning costs

Development costs include land options, wind assessment, site studies, equipment tendering, preliminary engineering, environmental assessment, and permit applications (Bryars et al. 2008). The institutional setting has a significant impact on costs. In a policy environment based on direct subsidies, where a third party assessment of project costs is obligatory in order to find the applicants with the lowest long-run marginal cost and where external parts have the right to file complaints, the project development is time consuming and the developer must account for the risk of not being accepted by the concession or payment authorities. Krohn et al. (2009) state that the development and planning costs can range between 5 and 10 percent of the total investment cost, while Bryars & Holt (2008) estimate the development cost to an average of 7 percent of the total investment cost.

6.1.5 Contingency

The level of contingency rises with the number of contracts to account for the increased interface risks. In this paper contingency is set at 5 percent of the investment costs.

6.2 Variable costs

All industrial equipment need repair, and wind power is no exception. In addition variations in the wind speed certainly do influence the cost of wind power. This section looks at the operation and maintenance costs.

6.2.1 Operation and maintenance costs

Compared to conventional power sources the operational costs for wind power are low and not influenced by variations in fuel prices. The O&M costs will depend on the number of wind turbines, the type of wind turbine, the site conditions and the connected system (Tande et al., 1994). Typically a breakdown of the O&M cost should include;

- Normal liability and property insurance.
- Special insurance for an annual energy output guarantee.
- Service costs, i.e. the cost of man-power.
- Repair costs, as in costs not covered by regular service and the insurance.
- Management/administration costs.

Based on German data from Deutsches Windenergie Institut (DEWI), Krohn et al. (2009) split the operation and maintenance cost into six different categories; land rent (18%), insurance (13%), service and spare parts (26%), miscellaneous (17%), power from the grid (5%) and administration (21%). They also report that there are signs of a decrease in the O&M costs over time. This could indicate that as the wind turbines gets larger and more robust they are more optimized for the wear and tear they are exposed to. Clearly, shown by Krohn et al. (2009), a comparison of O&M cost between the 55kW turbine and the 1000 kW shows a decrease in all O&M cost components, but the miscellaneous cost. The increase in miscellaneous cost is accounted to increasing prefeasibility costs.

Based on data from Germany, Spain, the UK and Denmark, operation and maintenance costs are generally estimated to be around c€1,2 to c€1,5 per kWh of wind power produced over the total lifetime of a turbine (Krohn et al., 2009).

Bryars & Holt (2008) find the O&M costs for the wind turbines to be in the region of 15000 and 20000 €/MW/annum during and after the warranty period. However, to account for increased uncertainty towards the end of the turbines' lifetime they find it «prudent to model 25000 to 30000 €/MW/Annum to understand the sensitivity of this figure». Further, they find the civil and electrical maintenance cost to range from €500 to €2000 per wind turbine per annum and €1000 to €3000 per turbine per year respectively. Insurance costs they claim to be in the range €3000 to €7000 €/MW/annum. Day to day management are measured to cost an average 3000 €/MW/annum. Management fees, which include banking, legal and secretarial requirements, are also estimated to 3000 €/MW/annum. Finally, they have defined other costs to include monitoring of the wind farm and power from the grid. The monitoring costs are assumed to range from 2400 to 20000 €/project/annum, while the importation of electricity at periods with low wind or service is estimated to an average 2200 €/wind turbine/annum. Based on the discussion above, the cost components have been calculated and a summary is provided in Table 6.1. Taxes are here ignored.

	Low	**High**
Turbine	57500	69000
Civil	500	2000
Electrical	1000	3000
Insurance	6900	16100
Salaries	6900	6900
Administration	6900	6900
Monitoring	2400	20000
Power import	2200	2200
€/WTG/annum	**84300**	**126100**
c€/kWh	**1,67**	**2,50**

Table 6.2: Total operation and maintenance costs for wind energy based on 2,3 MW wind turbines and 2189 full-load hours per year.

In Table 6.2 a high and low scenario for the total O&M costs is calculated. They range from c€1,6 to c€2,5, which is fairly consistent with the results in Krohn et al. (2008). Measured in 2008-prices, the O&M costs are in the range NOK 0,13 to 0,19.

6.3 Wind energy output

In Section 5.3 the cost calculation method was discussed. For convenience the formula for the levelized production cost will here be repeated,

$$LPC = I \cdot \frac{1}{R(r,T) \cdot ANE} + \frac{TOM}{R(r,T) \cdot ANE}.$$

Wind is the only fuel for wind power stations. By investigating the above condition we see that the annual net energy output (ANE) plays an important role in the calculation of the cost of wind power. The amount of energy that can be harvested at a given wind site depends on the local wind speed for that specific area and it is therefore important to provide a more thorough assessment of the calculation of the wind energy output. Although the energy output generated by natural resources varies from year to year, Section 5 assumed the energy output to be constant from year to year. In the assessment of the levelized cost calculation of wind power, we should pay attention to large variations in the ANE. It is, however, reasonable to assume that the annual wind energy output in average is equal over a time span of 20 years. The European Wind Atlas, the NVE, the Norwegian Meteorological Institute (DNMI) and several other companies[7] put a lot of effort into the measurement and estimation of wind speeds at locations suited for wind power production. For example, DNMI routinely forecasts the wind speed and direction along the Norwegian coast, while the NVE in cooperation with Windsim AS and DNMI newly published wind atlas which covers the Norwegian coast.

Sometimes these models are not accurate enough for predictions of wind in a specific wind farm, and further measurements could be necessary in order to predict the exact wind energy output at the given site. This point is underscored in Berge et al. (2003): «*The wind conditions along the Norwegian coast are complex and accurate wind predictions are not a trivial task. […] winds along the coast are influenced by the large scale high and low pressure systems moving in the polar jet stream over the North Atlantic Ocean toward the Norwegian coast. The winds generated by the low and high pressure systems are modified by the Norwegian mountain barrier, local hills, mountains and fjords. The sharp temperature contrasts between*

[7] Kjeller Vindteknikk and Storm Weather Center.

the sea and the surface areas are also important for the local wind systems along the coastline. Wind predictions, and thereby also predictions of the wind power production, must take all the above mentioned effects into account if reliable predictions are to be made».

In the following we will provide a theoretical description on how these effects make up the different components in the modeling of the ANE. As stated in Section 5, the formula for the ANE is,

$$ANE = E_{pot} \cdot K_{per} \cdot K_{site} \cdot K_{ava}.$$

E_{pot} is the annual potential energy output given as

$$E_{pot} = 8766 \cdot \int_0^{\infty} p(u) \cdot f(u) du,$$

where 8766 is the number of hours in a year, $p(u)$[8] is the power curve of the wind turbine, and $f(u)$ is the normalized wind speed probability distribution at the hub height of the wind turbine, typically expressed by a Weibull distribution.

The wind energy output from the wind turbines is reduced due to dirt, rain or ice on the blades. This reduction can be explained by the performance factor, K_{per}, defined as the ratio of the reduced annual energy output, ΔE_{per}, and the annual potential output,

$$K_{per} = 1 - \frac{\Delta E_{per}}{E_{pot}}.$$

In cases where the site surroundings may change with time due to erection of new wind turbines, new houses, etc., it may be adequate to apply a site factor, ΔE_{site}, in order to take account of the reduction in annual energy output,

$$K_{site} = 1 - \frac{\Delta E_{site}}{E_{pot} \cdot K_{per}}.$$

Sometimes the wind turbine or the grid system is out of operation. The technical availability factor, K_{ava}, is defined by the energy loss, ΔE_{ava}, due to the wind turbine availability

[8] $p(u) = p(u)_{std} \cdot \frac{\rho}{1{,}225}$, where is the power curve for standard conditions and ρ is the actual air density in kg/m^3. 1,225kg/m^3 is the standard air density.

$K_{site} = 1 - \frac{\Delta E_{site}}{E_{pot} \cdot K_{per} \cdot K_{site}}$.

In Table 6.2 reports estimations of wind speed and number hours per year based on a Siemens 2MW wind turbine.

Region	Estimated wind speed (m/s)	Full-load hours per annum
Vest Agder E	7,2	2460
Vest Agder W	7,5	2750
Rogaland C	8	2780
Rogaland N	7,8	2860
Hordaland S	7,5	2680
Hordaland N	7,8	2780
Sogn og Fjordane C	7,8	2770
Sogn og Fjordane N	8,2	2940
Møre og Romsdal C	7,8	2670
Møre og Romsdal N	7,8	2560
Sør Trøndelag	8,2	2930
Nord Trøndelag	8,5	3360
Nordland S	7,8	3030
Nordland CS	7,5	2760
Nordland CN	7,5	2850
Nordland N	7,5	2420
Troms S	7,8	2930
Troms N	8	2890
Finnmark W	8,5	3040
Finnmark C	8,5	2890
Finnmark CE	8,5	2880
Finnmark E	8	2720
Finnmark SE	7,5	2380

Table 6.3: Estimations of wind speeds and full-load hours at different Norwegian location (Source: NVE).

We see that annual full-load hours range from 2380 in south-east Finnmark to 3360 in Nord-Trøndelag. When we assess the costs for Norwegian wind power projects in later sections, we will sort the projects according to the area of origin and base the analysis on the respective production hours.

One should note that estimated full-load hours for Norway are smaller than what was first expected for Norwegian wind power. There are several reasons for this. First, it could be the case that the nature of the wind in Norway, even though at a larger maximum wind speed than the rest of Europe, is less suited for wind power production. On the one hand Norwegian topology may create large variations in wind speed, while the wind turbines are best fitted for climates with small variations in the wind speed. Secondly, when one first started to estimate wind speeds in Norway with regard to wind power, the estimations in Norway was partly based on methodology from Denmark and Germany. As the wind speed in Norway is higher than the rest of Europe, one concluded that the potential for wind power in Norway was one of the greatest in Europe, if not the World. However, and again due to the geographical issues, one learned that one had to establish new methods in order to get more precise measurements.

Finally, Hofstad (2009) reports the average reported wind production at 2189 hours for 2008. This large deviation from the expectations of up to 4000 production hours may be explained by the lack of experience in Norwegian wind industry. The wind parks may have been constructed after the Danish and German model, where flat landscapes dominate. Hence, the wind turbines at Norwegian sites may have been situated too close to each other, and thereby created a wind wake effect[9] larger than necessary. The two first effects points in the direction that the Norwegian wind potential is smaller than first expected and that new and better estimation technology will be more precise in the future. The last one is more optimistic, more experience will lead to an optimal and efficient utilization of the wind resources.

6.4 The Discount Rate

The estimation of the discount rate or the rate of return is usually based on data from the stock market and the use of the capital asset pricing model (CAPM). In the present discussion of the estimation of the discount rate we will first briefly present the CAPM-model. In its assessment of Norwegian wind power projects, Enova bases the calculations on the results in Gjølberg & Johnsen (2007). Their study concludes that the rate of return for new renewable energy projects in Norway should be 8 percent. Dalen et al. (2008) criticizes the use of the stock market for the estimation of the rate of return. They argue that the stock market is biased towards a too high level of the rate of return.

The level of the discount rate plays an important role in the assessment of the profitability of a given project. The higher the discount rate the smaller the number of projects with a positive net present value. Investment companies' and project developers' willingness to invest in a given wind power project is therefore highly dependent on the level of the discount rate (Dalen et al., 2008).

[9] There will be a wake behind the turbine. A wake is a long trail of wind which is quite turbulent and slowed down, when compared to the wind arriving in front of the turbine. The expression is derived from the wake behind a ship or a boat.

6.4.1 The Capital asset pricing model

To capture the risk involved in public investments economists often focus on the stock market. It is assumed that in the stock market the actors will diversify until they are only left with the systematic risk. Systematic risk is the risk one cannot diversify away from. The most common model used to put a price on risk is the capital asset pricing model (CAPM).

Let r be the risk free interest rate. $R_j$is the return from investment in project j and $R_m$is the return from the market portfolio. The risk premium in project j, defined as the difference between expected return from the project, $E[R_j]$, and the risk free interest rate r, is proportional with the market portfolio risk premium, $E[R_m] - r$, where the factor of proportionality is β_j. This gives the following condition

$$\{E[R_j] - r\} = \beta_j\{E[R_m] - r\}$$

or

$$E[R_j] = r + \beta_j\{E[R_m] - r\} .$$

In words, the risk premium of project is equal to $\beta_j\{E[R_m] - r\}$.

An asset with a beta of 0 means that its price is not at all correlated with the market, a positive beta means that the asset generally follows the market, and a negative beta shows that the asset inversely follows the market. The formula of the beta of an asset within a portfolio is

$$\beta_j = \frac{cov(R_j, R_m)}{\sigma_m^2} = \frac{\rho_{jm}\sigma_j}{\sigma_m},$$

where $cov(R_j, R_m)$ is the covariance between the rates of return, σ_j and σ_m is the standard deviation in the risk distribution to project j and the market portfolio, ρ_{jm} is the correlation between the return from project j and the market portfolio return. β_j can be estimated from the stock market.

To evaluate the risk associated with a given project in economic terms, information on the extent to which the return from the project correlates with the country's total wealth is needed. The return from the total wealth is the national income. R_m represents this return. The risk premium, $E[R_m - r]$, can be calculated as the difference between the return from the index at the stock market, i.e. the Oslo Stock Exchange, and the risk free interest rate. When this number is multiplied with the correct β for the given project j, an estimation of the economic risk is provided.

6.4.2 What is the right level of the discount rate?

Gjølberg et al. (2007) bases their research on the rate of return within the new renewable energy industry on the CAPM-model. First they look at selected firms within the renewable industry and compare the systematic risk with the one within the more conventional energy industry. They find that during the past years the beta-value has increased for all energy companies, though it seems like the beta-value for companies within the renewable energy industry has increased more than what is the case for more traditional and integrated energy companies. Further, they compare different portfolios of renewable energy companies, which has been established during the past years, and conventional energy indexes. They find that energy is a risky industry, and new renewable energy technology is riskier than the conventional. Total risk measured by the standard deviation is high for all energy indexes. For the period 2004 to 2007 wind power has a standard deviance of 33 percent, while it is 26 percent for oil, 18 for an index of all energy companies and 7 percent for the world index. Based on the indexes they conclude that the beta-value for renewable energy in general is relatively high, as high as 1,49-1,67 for the period 2004-2007. This indicates a high systematic risk and, according to the authors, higher than the conclusions of other papers.

Gjølberg et al. (2007) find the beta-value for wind power at 0,80. They use a 5 percent nominal risk free interest rate, which is the calculated from the sum of the long term real interest rate at 2,5 percent and the Norwegian Central Bank's inflation target at 2,5 percent per annum, a market premium at 4 percent, a debt ratio at 0,4 and a credit premium at 1, 5 percent. Through the CAPM-model they then find the rate of return for Norwegian wind power at the 8 percent level.

This level is 2 percentage points higher than the recommendations of the Norwegian Ministry of Finance (2005) and Dalen et al. (2008). Gjølberg et al. (2007) bases the deviation from recommendation of the Norwegian Ministry of Finance on three arguments; (i) the Ministry bases it analysis on the present interest rent rather than the long term interest rate, (ii) the Ministry uses a too low credit premium and a too high debt ratio, and (iii) the Ministry uses a too low beta-value at 0,5, which is a representative beta-value for Norwegian companies registered on the Oslo Stock Exchange, but not representative for investments in energy related companies. By adjusting for these measures, Gjølberg et al. (2007) argues that the correct recommendation from the Norwegian Ministry of Finances should be a rate of return at 9 percent.

On the other hand, Dalen et al. (2007) points to two arguments that point in the direction of the long run discount rate not to be based on the private capital market; (i) manager's short horizon can lead to myopic behavior (Stein, 1989) and (ii) inefficient stock markets. In the former case the firm's manager typically mislead the market about their firm's real market value by boosting short-run earnings on the cost of long-term investment. Through this behavior they can achieve a higher stock price in the short run. Estimations of the discount rate based on a stock market with a high level of myopic corporate behavior may lead to a too high discount rate. There is a conflict of interest between the stockowners and managers, who want to maximize short-term profits, and the best interest of society. In the latter case inefficient stock markets are caused by overrated stocks. A rise in the stock price is caused by an adjustment in the underlying value of the company, but this does not necessarily mean that all actors in the stock market have the same view (Dalen et al., 2008). Dalen et al. (2008) refer to Bolton et al. (2006) and argue that the stock market sometimes receives overoptimistic actors, and that this optimism causes other actors to behave shortsighted and speculate in companies with even negative net present values.

Dalen et al. (2007) argue that the discount rate should be 6 percent in the first face of the projects' lifetime, and decline to 4 percent after 20 years.

6.5 Other cost components

6.5.1 External costs

External costs of energy production are those which are borne by third parties and are not reflected in the market price of energy. These costs are often associated with environmental damage, nuisance for people, etc. In Great Britain the external costs of wind power was examined at two different sites by the means of a willingness to pay method (ECON, 1998). This method, however, is much debated and attracts a lot of criticism. There is no consensus on specific methods for estimation of external costs, but it is accepted that external costs exist and therefore should be included when calculating the costs of energy production (Tande et al., 1994). However, compared to energy generation from non-renewable sources, it is widely accepted that the external costs of wind energy are small or negligible. This paper analyses the costs of 12 Norwegian wind power projects. All 12 have been evaluated by the Norwegian Water Resources and Energy Directorate (NVE) and all 12 projects are accepted through cost-benefit-analyses. Based on the NVE's analyses it is assumed that the benefit of the projects exceeds the costs, hence the external costs are approximated to zero and not considered.

6.5.2 Economic lifetime

Most of the wind turbines that were installed in the 1980s are either still operating or were replaced before the end of their technical life due to special repowering incentives. In their payment assessment, Enova bases the calculations on an economic lifetime of 20 years. The economic lifetime should not be set to a value larger than the technical life of the wind turbines. Modern wind turbines are commonly designed to have a life of 20 years, and this paper assumes a 20 year economic lifetime.

6.5.3 Salvage value

The salvage value is defined as the difference between the scrap value and the decommissioning cost of the entire scheme at the end of the economic lifetime. If the economic lifetime is set equal to the technologic lifetime of the wind turbine, the salvage value may not be zero as land, electrical cables etc. may still have capital value. Although this may be true for Norwegian wind sites, the NVE requires the projects to decommission the installments at the end of the authorization period. We will here assume that the decommissioning costs equals the scrap value, hence the salvage value is set to zero.

6.6 Long-run marginal cost curve

When all cost components are defined, we are ready to calculate the long-run marginal cost curve for wind power. Figure 6.1 shows the long-run marginal cost curve, based on the cost components and calculations in Table 6.1 and 6.2, as a function of full-load hours per annum for discount rates at 6 and 8 percent.

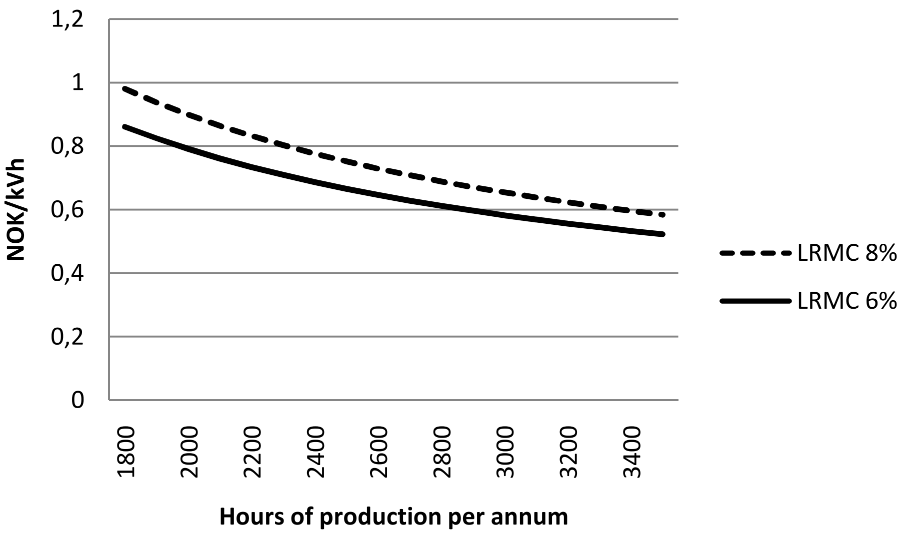

Fig. 6.1: Long run marginal cost curve as a function of the hours of total production per annum. 2008-prices.

6.7 Uncertainties

In the previous sections we have presented the best estimates of the input parameters. In this section we will look at the sensitivity of each parameter, θ_i, defined as the partial derivative of the LPC with regard to the specific parameter, x_i:

$$\frac{\delta LPC}{\delta x_i} = \theta_i.$$

We would expect the partial derivative of the LPC with respect to the annual hour of production and the economic lifetime to be negative. In other words, as both these parameters increase, we would expect the levelized production cost of wind power to decrease. Vice versa, for the three other parameters, the investment and O&M costs and the discount rate, we expect increasing costs as the parameters increase.

The uncertainty analysis is done by calculating the levelized production cost based on the investment and O&M costs provided above, a discount rate of 6 percent, 2800 full-load hours per annum and an economic lifetime of 20 years for a 2,5MW turbine. Then, keeping all other parameters constant, the specific parameter has been moved marginally in the positive and negative direction. The result is presented in Figure 6.2.

Krohn et al. (2009) state that «*the turbine's power production is the single most important factor for the cost per unit of power generated*». Inspection of Figure 6.2 proves their point. The wind speed, location of the wind site and the wind turbines has a large effect on the production costs. For example, will an increase from 2800 full-load hours to 3080 full-load hours, an increase of 10 percent, decrease the unit cost from NOK 0,61 to NOK 0,57 NOK.

Since wind power is a capital intensive industry, inspection of the LPC-formula in chapter 5 shows that the cost of capital is an important factor. Hence, the choice of the discount rate plays an important role. As illustrated, doubling the discount rate from approximately 5 percent to approximately 10 induces an increase in the production cost level from NOK 0,59 to NOK 0,80 or 35 percent.

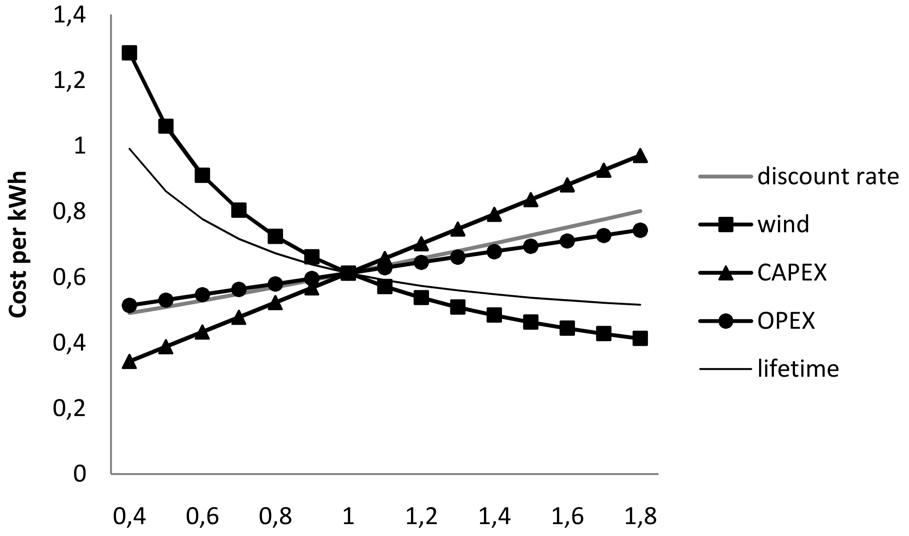

Fig. 6.2: Variation of input parameters. The input parameters considered are the discount rate, the wind speed measured as full-load hours per annum, the investment cost, the O&M cost and the economic lifetime.

6.7 Costs: A closer look at specific wind sites in Norway

In this section the levelized production costs for 12 wind energy projects are calculated. The selection of these specific projects are based on three criteria: (i) The NVE must have approved the wind farms application for concession, (ii) the wind farms must through their application for concession report of planned investments larger than 10 MW, and (iii) the wind farms are to be constructed onshore. It is reasonable to assume all offshore wind power plants to be significantly more expensive than onshore wind power plants per se.

6.7.1 Cost components reassessed

The reported cost levels of the different cost factors in Table 6.4 are based on the calculations presented above and data from the Norwegian Wind Energy Association and ECON (1998). For the latter the data has been adjusted according to the Consumer Price Index (CPI) and are explained further below.

ECON (1998) predicts the cost for overhead power lines to NOK 250 per meter, including works. Ground and submarine cables are certainly more expensive, and were estimated to NOK 650 and NOK 1000 respectively. The total length of cabling per wind site is reported in the application for concession to the NVE. Based on the CPI, the 2008-price would be NOK 307, NOK 800 and NOK 1200 per meter respectively.

ECON (1998) reports the 1998-price for medium to high voltage transformers in the area of NOK 7-8 million. Based on the consumer price index, the 2008-price per transformer would be NOK 9,85 million.

One of the criteria for approval of the concession application is that the wind farm is located in areas in the need for new electricity production. Normally the grid fee charged by the TSO, Statnett, is Nøre 0,53/kWh, but in the regions of electricity shortfall there is a rebate at Nøre 0,1/kWh. We will assume that the wind farms considered in this analysis and reported in Table 6.4 below have received approvals based on being located in shortfall regions. Therefore the grid fee calculations are calculated on the basis of Nøre 0,1 per kWh and that the total generated electricity is supplied to the grid. The tariff rebate agreement between the producer and Statnett is valid for 15 years (Statnett, 2009), but it is for simplicity assumed to last five more years.

DEVELOPMENT COSTS (kNOK)	**Cost**	**Unit**
Announcement	250	NOK
Concession application	4500	NOK
Wind measurement	1000	NOK
Data analysis	100	NOK
Appeal	500	NOK
OPEX (NOK)		
Service agreement, year 1-5	500000	NOK/turbine
Service agreement, year 6 -20	700000	NOK/turbine
Ecology studies	500000	NOK
Grid fee, year 1-20	0,1	Nøre/kWh
Electricity import	0	NOK
Property tax (of 70% of CAPEX)	70	%
Road maintenance	100000	NOK/annum
Financial cost	20000	NOK/annum
Administration cost	0	NOK
Site costs	300000	NOK/annum
CAPEX (kNOK)		
TSA	25675	NOK/turbine
Transformer (690V / 22 kV)	440	NOK/turbine
Foundation	1800	NOK/turbine
Crane pads	300	NOK/turbine
External roads	2000	NOK/km
Internal roads	1000	NOK/km
Transformer (22kv / 132kV)	10000	NOK/turbine
Aerial cabling	300	NOK/km
Underground cabling	800	NOK/km
Submarin cabling	1200	NOK/km
Service station	10000	NOK/turbine
Connecting to the grid	20000	NOK
Organization	10000	NOK
Insurance	3000	NOK
Contingency	5	%

Table 6.4: The table provides an overview over the cost components which upon the estimations of the levelized production costs for the Norwegian wind power sites are based.

6.7.2 LPC-assessment of Norwegian wind power plants

Table 6.5 reports the levelized production costs for the 12 wind farm projects. The calculations are based on public available applications for concession at the NVE. The LPC ranges from NOK 0,47 to NOK 0,67 given a discount rate of 6 percent. A discount rate of 8 percent leaves us a cost interval between and NOK 0,54and NOK 0,76. The estimated full-load hours are based on estimations by the NVE from Table 6.3.

Project	Owner	Region	Full-load	GWh	Discount rate 6 %	Discount rate 8 %
Ytre Vikna	NTE ENERGI	Nord-Trøndelag	3 360	765	0,47	0,54
Harbaksfjellet	WIND POWER	Sør-Trøndelag	3 360	255	0,49	0,55
Kvitfjell	NORSK MILJØKRAFT	Troms	2 890	532	0,54	0,61
Andmyran	ANDMYRAN VINDPARK	Nordland	2 850	420	0,55	0,62
Høg-Jæren	JÆREN ENERGI	Rogaland	2 780	205	0,57	0,64
Fakken	TROMS KRAFT	Troms	2 890	113	0,60	0,68
Midtfjellet	MIDTFJELLET VINDKRAFT	Hordaland	2 680	185	0,61	0,69
Haram	HARAM KRAFT	Møre og Romsdal	2 670	147	0,61	0,69
Nygårdsfjellet 2	NORDKRAFT VIND	Nordland	2 850	72	0,62	0,70
Tysvær	TYSVÆR VINDPARK	Rogaland	2 860	86	0,62	0,70
Mehuken 2	KVALHEIM KRAFT	Sogn og Fjordane	2 940	54	0,64	0,73
Lista	NORSK MILJØ ENERGI SØR	Vest-Agder	2 460	175	0,67	0,76

Table 6.5: Levelized project costs for selection of Norwegian wind power sites based on a 6 and 8 percent discount rate. The estimates are based on 2,3 MW wind turbines and estimated full-load hours reported by the NVE.

The annual full-load hours might be too optimistic in Table 6.6. Hofstad (2009) reports that the average annual full-load hours to 2189. In Table 6.6 the LPC is calculated as function of the updated full-load hours.

Project	Owner	Region	Full-load	GWh	Discount rate 6 %	Discount rate 8 %
Kvitfjell	NORSK MILJØKRAFT	Troms	2 189	403	0,71	0,80
Andmyran	ANDMYRAN VINDPARK	Nordland	2 189	322	0,72	0,81
Høg-Jæren	JÆREN ENERGI	Rogaland	2 189	161	0,72	0,81
Ytre Vikna	NTE ENERGI	Nord-Trøndelag	2 189	498	0,73	0,82
Haram	HARAM KRAFT	Møre og Romsdal	2 189	121	0,75	0,85
Midtfjellet	MIDTFJELLET VINDKRAFT	Hordaland	2 189	151	0,75	0,85
Harbaksfjellet	WIND POWER	Sør-Trøndelag	2 189	166	0,75	0,85
Lista	NORSK MILJØ ENERGI SØR	Vest-Agder	2 189	156	0,75	0,85
Fakken	TROMS KRAFT	Troms	2 189	86	0,79	0,90
Nygårdsfjellet 2	NORDKRAFT VIND	Nordland	2 189	55	0,80	0,91
Tysvær	TYSVÆR VINDPARK	Rogaland	2 189	65	0,81	0,91
Mehuken 2	KVALHEIM KRAFT	Sogn og Fjordane	2 189	40	0,86	0,98

Table 6.6: Levelized project for selection of Norwegian wind power sites calculated as a function of 2189 annual full-load hours.

What if we assume an 8 percent decrease in the cost level relative to the calculations provided in Table 6.5? An 8 percent cost decrease relates to the maximum expected cost decrease for wind power by the use of experience curve methodology (see Section 8.2 for more on experience curves). The result is presented in Table 6.7.

Project	Owner	Region	Full-load	GWh	Discount rate 6 %	Discount rate 8 %
Ytre Vikna	NTE ENERGI	Nord-Trøndelag	3360	765	0,44	0,49
Harbaksfjellet	WIND POWER	Sør-Trøndelag	3360	255	0,45	0,51
Kvitfjell	NORSK MILJØKRAFT	Troms	2890	532	0,50	0,56
Andmyran	ANDMYRAN VINDPARK	Nordland	2850	420	0,51	0,57
Høg-Jæren	JÆREN ENERGI	Rogaland	2780	205	0,52	0,59
Fakken	TROMS KRAFT	Troms	2890	113	0,55	0,63
Midtfjellet	MIDTFJELLET VINDKRAFT	Hordaland	2680	185	0,56	0,64
Haram	HARAM KRAFT	Møre og Romsdal	2670	147	0,57	0,64
Nygårdsfjellet 2	NORDKRAFT VIND	Nordland	2850	72	0,57	0,64
Tysvær	TYSVÆR VINDPARK	Rogaland	2860	86	0,57	0,64
Mehuken 2	KVALHEIM KRAFT	Sogn og Fjordane	2940	54	0,59	0,67
Lista	NORSK MILJØ ENERGI SØR	Vest-Agder	2460	175	0,62	0,70

Table 6.7: Levelized project for selection of Norwegian wind power sites, now calculated with a 8 percent decrease in the cost level relative to Table 6.5.

If a technology is to reach its grid parity it must either reduce its long-run marginal cost or the energy price has to increase. The cost decrease reported in Table 6.7 will be discussed in relation to the electricity price in Chapter 8.

7. Price scenarios

Chapter 5 underscores the fact that the cost for the last produced unit of electricity at the point where it equals the demand for electricity per definition reflects the market price. Hence, wind power reaches grid parity at the point in time where the levelized production cost equals the market price for electricity. In order to identify the point in time where the levelized production cost of wind power equalizes the market price, information about the future electricity price is needed. This section describes the price setting in a liberal market and uses scenario methodology to simulate the future price scenario in the Norwegian electricity market. Appendix A shows the results for the simulation of the northern European markets.

7.1 The liberalized electricity market

This section is based on Morthorst et al., (2005). How will the prices in the Norwegian and European electricity market develop in the future? In an assessment of the development of wind power, the question proves to be important. First, the electricity price plays a large role in the profitability of wind power, after all the price you can get for the good in the market does play a significant role in any firm's revenue. Second, along with the long run marginal cost development, the market price development decides if and when a given technology is to reach its grid parity. Third, the size of future subsidies to technologies that has not reached its grid parity, given government's positive willingness to invest in these technologies, is largely dependent on the market price.

A lot of factors influence the price setting of electricity: The oil and coal price, the development of new energy capacity including wind power, the development of the price for CO_2 and demand. In addition may a full liberalization of the European electricity market influence price.

Electricity markets that are highly dominated by hydro power production normally see price variations in regard to normal, wet and dry years. Changes in the amount of river flow will correlate with the amount of energy produced by a dam. In a dry year diminishing river flow may result in power shortage and higher prices, in a wet year more than average river flow will normally result in lower prices.

Countries with a high portion of wind power in the energy mix are also subject to annual variations in the wind speed. In years with little wind, less power will be generated and the price will generally increase. Vice versa, in windy years the expected power generation is higher and the power price lower. According to Morthorst (2005) a windless period during a normal year can lead to price peaks of 500-600 NOK/MWh in Denmark.

The integration of hydro and wind power provides unique opportunities. By the fact that hydroelectric power plants normally have at least one storage reservoir, the load factor is highly predictable. At the same time, wind power is variable in its nature. The combination of the two power sources presents real-time smoothing of wind power's production variability, as well as an option for energy storage.

Countries with a large energy production from hydro power also benefit from the flexibility from the storage reservoirs. Hydro power plants may produce electricity to supply at high peak demands during daytime, and thereby reduce the fluctuations in price.

The temperature during the winter season also plays a large role. Cold winters lead to higher demand for heat and electricity which again causes higher prices. When it comes to demand, it is worth mentioning that electricity price elasticity is rather low. This means that an increase in the price of one unit has a small impact on demand. Measures to increase the price elasticity would contribute to a reduction in electricity consumption at periods of high prices.

The participants in the electricity market deliver their bids to the Nord Pool spot market based on generation predictions 12 to 36 hours before real time production. The producers make their bids in the estimated production capacity at a given hour, and the consumers, mostly represented by the utilities, inform the market how much they demand to what price at the given hour. Together this information establishes the aggregate supply and demand curve for electricity, whereas the price is decided by the equilibrium, see Figure 7.1. In the perfect market all producers and all consumers are price takers. The producer will offer all its available capacity at a price level that equals his short-term marginal cost, which implicates that he is willing to produce when he at least can cover total variable costs. Production technologies with the lowest short-term marginal costs will typically be capital intensive wind and nuclear power production. These technologies therefore make up the lowest part of the supply curve and will normally run at full capacity. Power plants that normally have high (short-term) marginal costs, i.e. natural gas, oil and coal, make up the upper part of the supply curve. In the case of hydro power the price bids will typically depend on the level of water in the reservoirs.

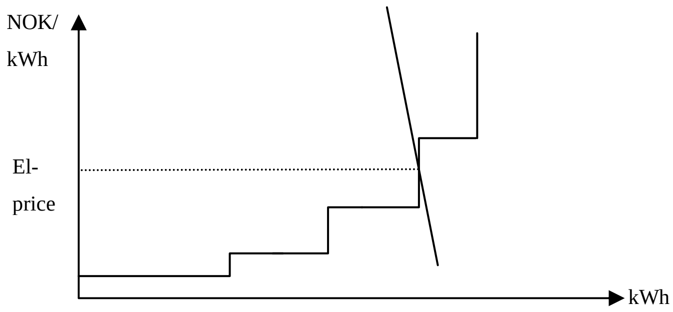

Fig. 7.1: Price setting in the electricity market.

In the perfect marked market, the demand curve reflects the total marginal willingness to pay. The consumers' total willingness to pay provides information about how much the electricity is worth in terms of utility. The market equilibrium reflects the maximization of the aggregate supply and aggregate demand curve. Through the equilibrium the market defines an electricity price and production which maximizes the economic surplus.

7.2 Price variations in the perfect competitive market

Price variations in the electricity market are due to variations in demand and supply, and security of supply. The consumption of electricity varies during a given day. Normally, we will see lower consumption during nights and therefore lower prices than during daytime when consumption and the price is higher, see Figure 7.2. At nighttime the demand for electricity usually is covered by the power plants with the lowest variable costs. At some hours during the day, the demand can exceed the current supply. In these situations the price setting is based on the consumers' willingness to pay and not the short-term marginal production costs. These situations, however, do only occur in cases of capacity restrictions. The consumers' willingness to pay is therefore revealed in hours of shortage in electricity production.

As described, the price for electricity varies due to variations in demand at a given daytime or season. The supply, on the other hand, varies with yearly or seasonal resource availability, i.e. wet or dry season, windy or wind still seasons, grid maintenance or grid havoc, start-up costs and grid constraints.

Situations in which price peaks occur are shown in Figure 7.2. At the higher part of the cost curve we find the gas powered power plants. The electricity supply is in this situation not high enough to clear the market. Since all capacity is in use, the price must increase in order for the market to clear. Hence, the price reveals what the consumers are willing to pay at the margin.

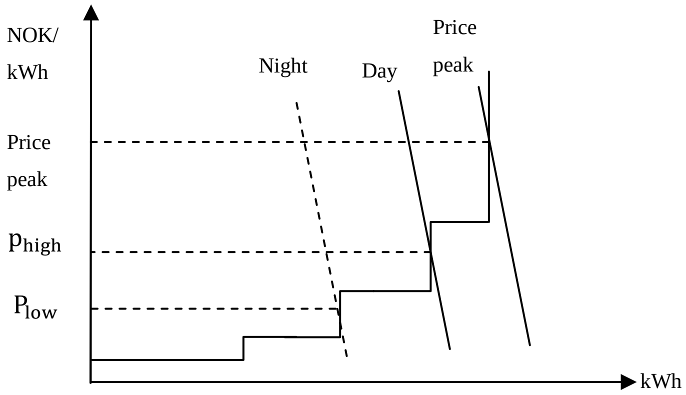

Fig. 7.2: Shifts in the demand curve and price peaks.

Seasonal inflow variations have a large influence on the price construction in the Nordic electricity market. The inflow to hydro energy plants is free, but the use of stored water in current power consumption has a opportunity cost as it can be stored for future power consumption. The opportunity cost of stored water is referred to as the water value. The water value depends on the total water stored relative to the normal water level at a given time of the year. The hydro power has a significant effect on the price setting on the spot market at the Nord Pool. During wet years the supply curve will move to the right and generate lower prices than what we usually see during normal years.

As we saw in chapter 6, the short-term marginal cost for wind power production is low. In the construction of the electricity supply curve, wind power constitutes the lower part of the curve. If large production from wind power concurs with price peaks or higher consumption, it will influence the electricity price. At the same time the price effect from wind power is negligible during periods of low consumption. Generally, due to low short-term marginal costs a high penetration level of wind power will lead to a lower average electricity price.

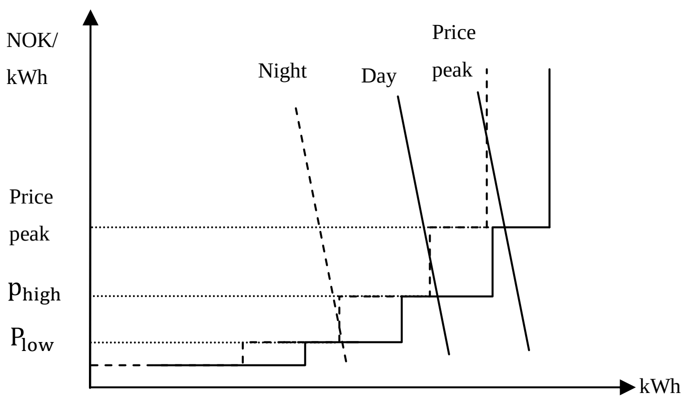

Fig. 7.3: Price variations in cases with more wind power in the electricity market.

The supply of electricity decreases at longer periods of power plant breakdowns. The supply curve shifts to the left. This has an effect on all three consumption periods, all though the sharpest price increase happens in the high consumption and price peak regions.

7.3 Future price scenarios

The scenario projections in this paper are derived from a large-scale mathematical model, the BID, originally designed by ECON. The BID-model simulates the water value and then simulates the electricity marked for given exogenous assumptions. The model is short-sighted with no investments, and assumes perfect competitive markets. The current analysis draws on historical data provided by the BID and the author's assumptions on the future energy trends. The assumptions are based on the «wind and consumption growth-scenario» originally designed by Statnett (Statnett, 2008)[10]. The main elements in this scenario are a large growth of wind energy in Norway and a potent climate policy. The former relies on the introduction of an ambitious incentive regime for renewable energy. Along with an assumed technological progress within wind power, this creates the basis for large scale wind power energy production. For the latter it is assumed that the cap-and-trade system, similar to the Emissions Trading Scheme that is currently operating in the European Union, is continued at a CO2-quota price of €25 per tonne, which is reflected in the power prices. In this scenario the world economy is growing at a moderate pace with the oil price set close to IEA's expectation at $60 per barrel (IEA, 2008). Further, it is assumed that climate change will causes increased inflow and increased production from hydro power plants. The relative high growth in power supply gives a moderate price level for electric power and weak incentives for energy economization in this scenario. It is also assumed that some transition to electricity in the transport sector, which causes a somewhat higher demand.

The main elements of the scenario:

- Increased oil activity in Finnmark and the electrification of offshore oil sites results in consumption growth in the petroleum sector of 11 TWh.
- Wind power increases to 19 TWh, including 2,5 TWh from offshore wind energy production.
- Hydro power increases with 3 TWh.
- Electricity consumption in the paper industry decreases with 5 TWh.
- KII increases with 5 TWh.

[10] The price calculations are done by the author.

- The power surplus is 7 TWh.
- Three cable connections to UK, Holland and Denmark are finalised.

In addition, the analysis includes a Swedish green certificate market, with certificate prices set to €16/tonnes CO2 and the green certificate requirements set to 12,6 percent of the total electricity consumption for households, services and industries, excluding power intensive industries. When it comes to the Norwegian climate policy, the analyses does not include a specific type of subsiding regime other than a large effect reflected in the relatively large production of Norwegian wind power. Regarding wind power the full-load hours for Norwegian sites is set to 3000.

The estimations are done by simulating 25 different inflow years for 8760 hours per annum. The average price for the every hour (1,2,…,24) for a given week (1,2,…, 52) is reported in the figures below. Due to capacity constraints the different parts of Norway do to a certain extent exist as independent price areas. The analysis has taken this into consideration and the results are presented for the five areas Finnmark, North-, Mid-, West- and South-Norway. The eastern region is excluded as the construction of wind power here seems improbable.

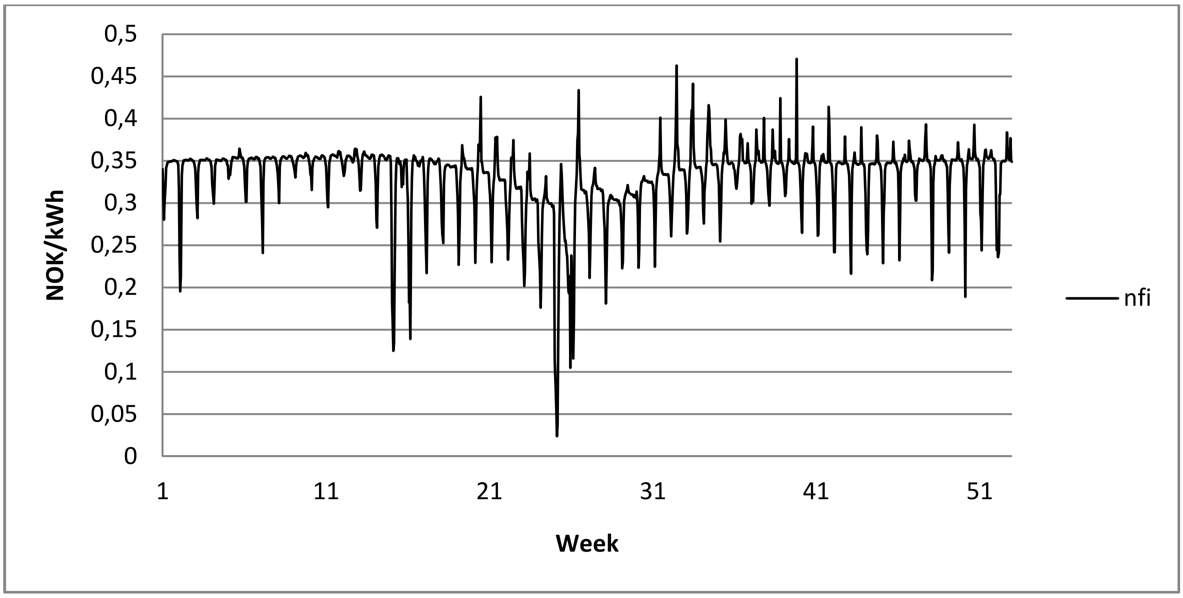

Fig. 7.5: Future price scenario for Finnmark.

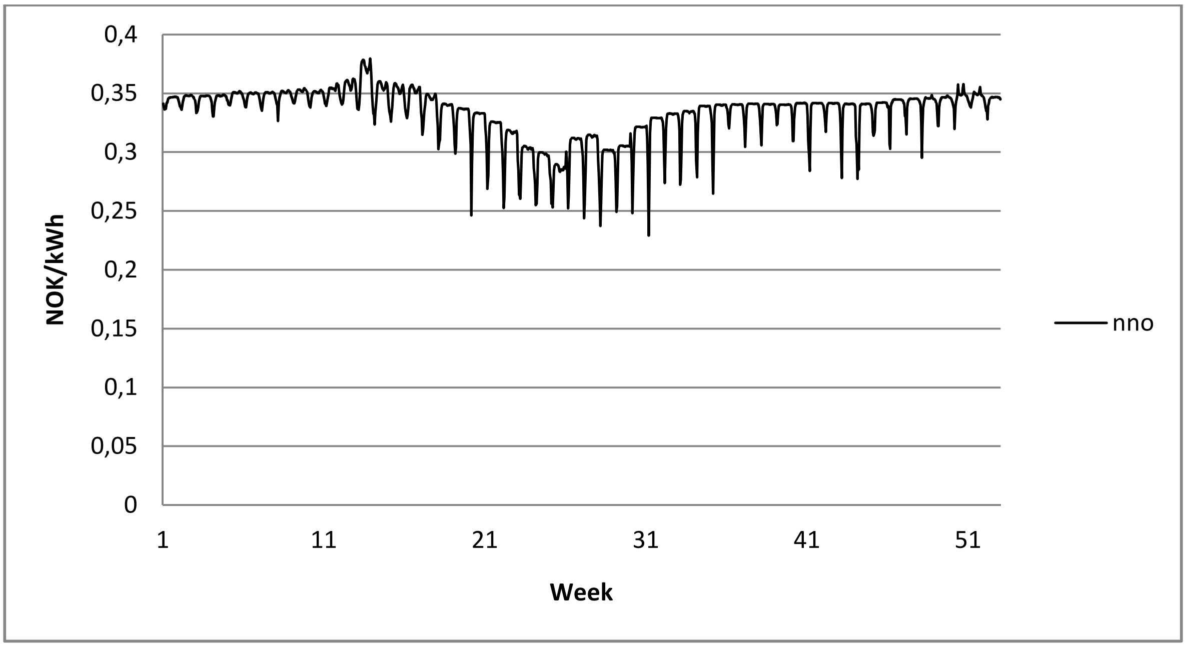

Fig. 7.6: Future price scenario for North-Norway.

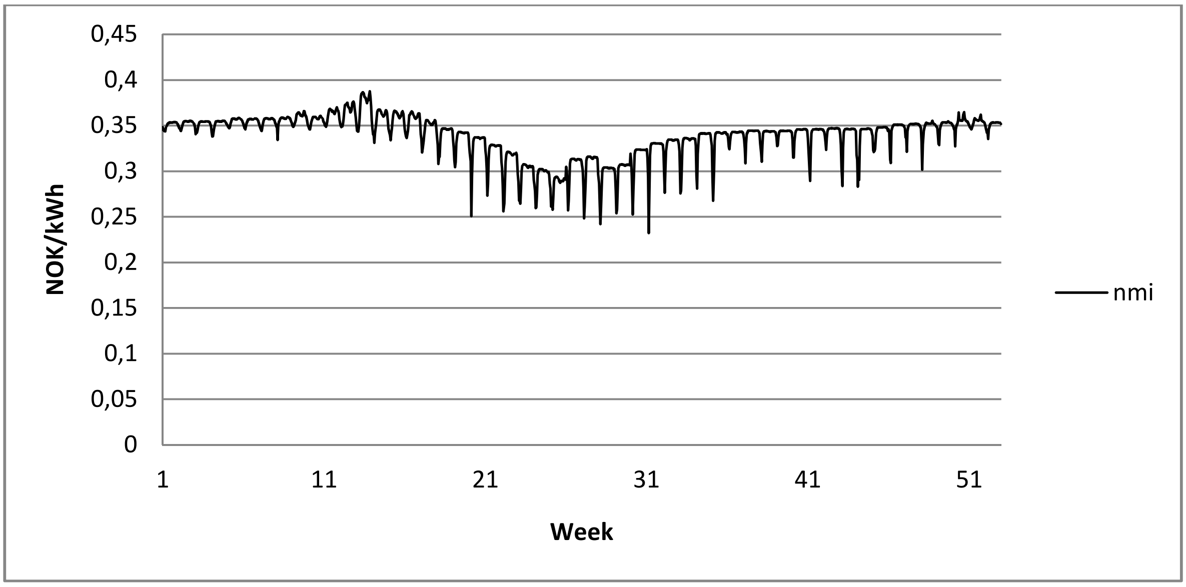

Fig. 7.7: Future price scenario for Mid-Norway.

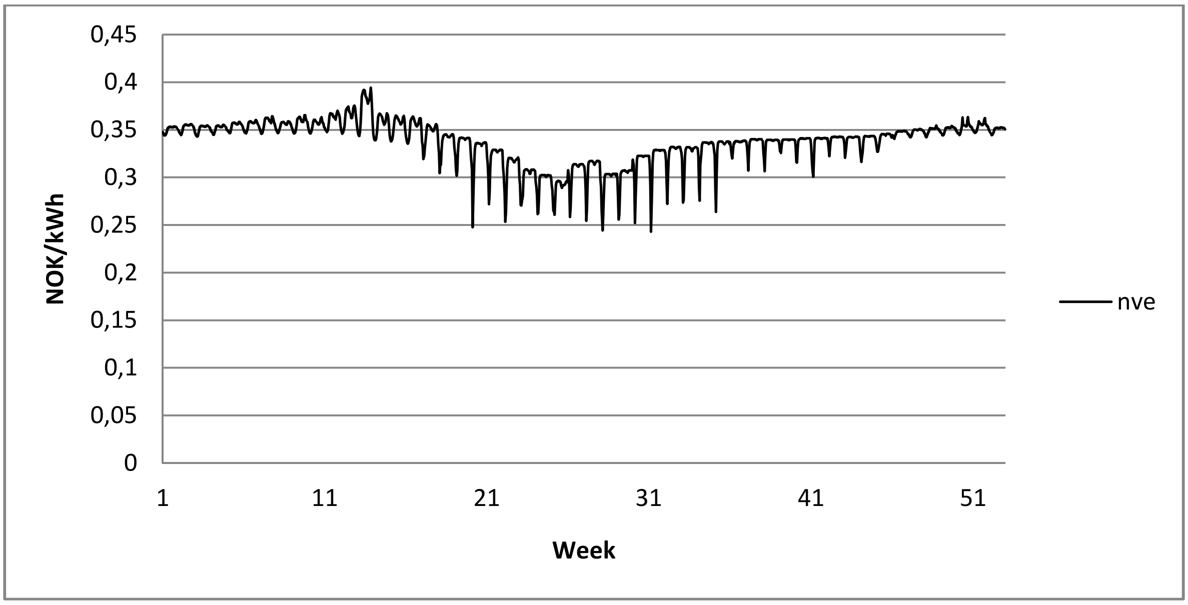

Fig 7.8: Future price scenario for West-Norway.

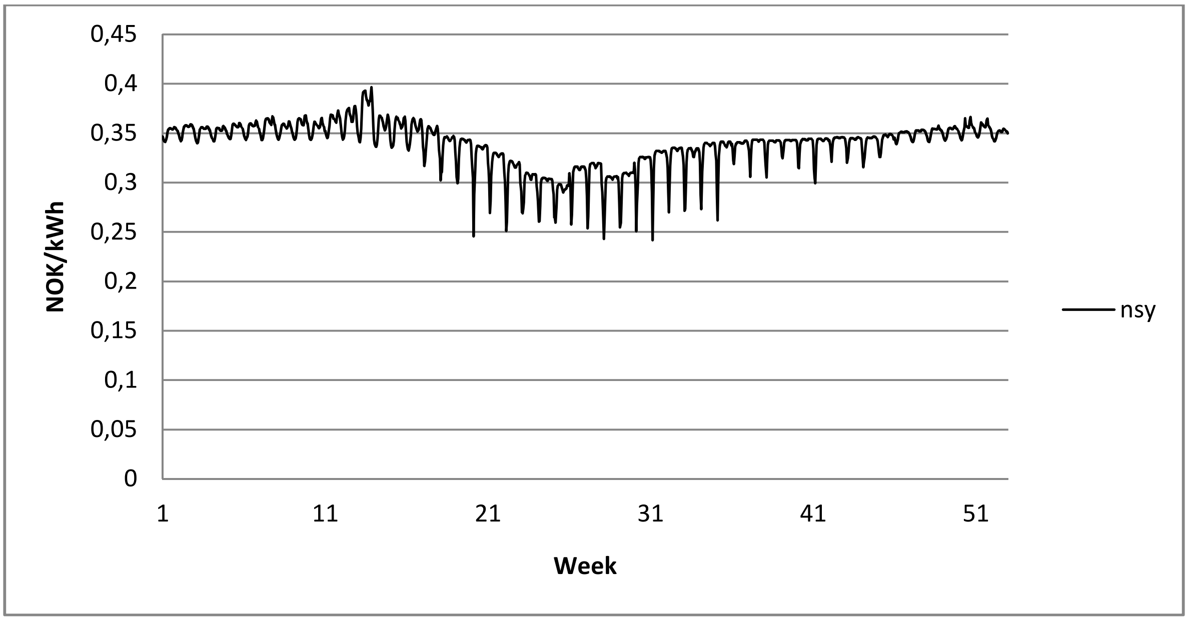

Fig. 7.9: Future price scenario for South-Norway.

For all five price regions, we see the same daily and seasonal tendencies: Higher prices during daytime and winter and lower prices during nights and summertime. We also see a trend of rising prices from the summer weeks towards fall. The more volatile prices for Finnmark can be explained by grid capacity constraints. The average prices are NOK 0,33 for all regions. Finnmark records the both the maximum and minimum prices at NOK 0,47 and NOK 0,02 respectively.

8. Grid parity and future cost development

The purpose of this work has been to study the grid parity for wind power – the point at which the cost of electricity from wind power will equal the cost of producing electricity by traditional means without taking into consideration subsidies. This section compares the levelized production costs derived in Section 6.7.2 with the average price for Norway, Sweden, UK, the Netherlands, Denmark and Germany by the use of a Salter-diagram. In the Salter-diagram the column width represents the production of a given wind project while the column height represents the LPC. The average price is computed from the price data from the scenario in Chapter 7. In the Salter-diagram grid parity is reached at the point where prices are equal the long-run marginal cost.

8.1 Grid parity

Figure 8.1 shows the Salter-diagram based on the 12 Norwegian wind farms addressed in Table 6.5. In order to reach its grid parity the LPC must equate the cost of conventional power production reflected through the energy price. Inspection of Figure 8.1 shows no signs of grid parity.

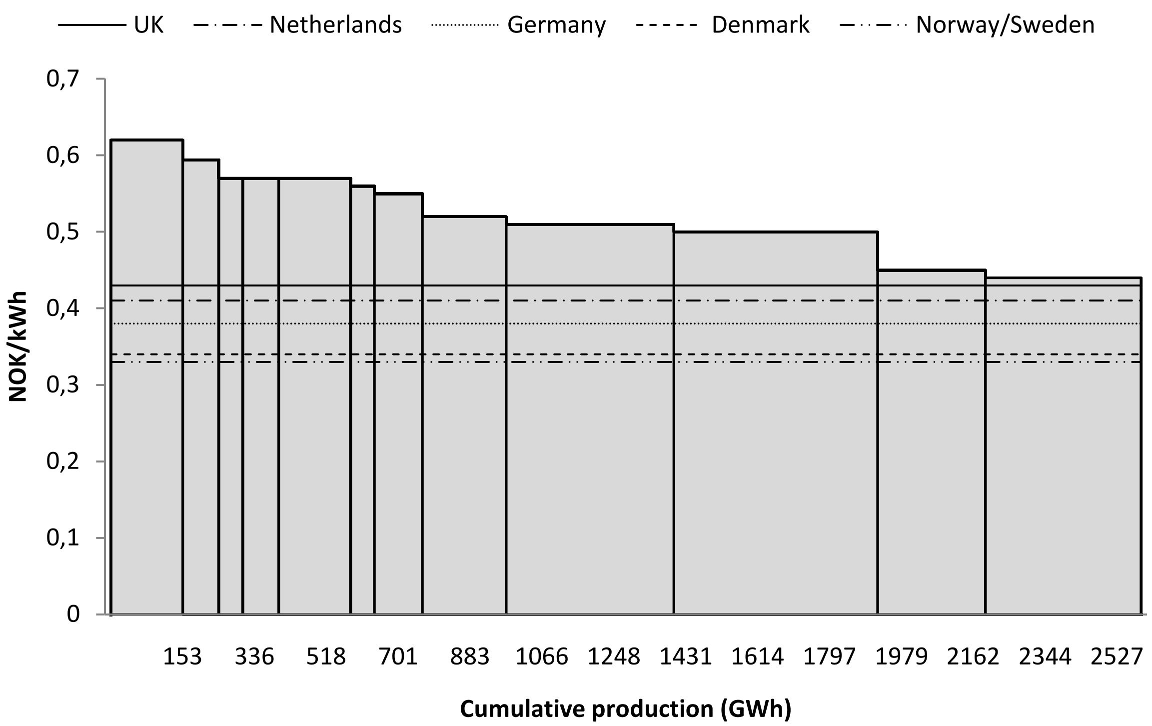

Fig. 8.1: Salter-diagram.

8.2 Future cost development

Experience curve methodology describes how cost declines with cumulative production, where cumulative production is used as an approximation for the accumulated experience in producing and employing a technology (Neij et al., 2003). Characteristic for the experience curves is that cost is reduced by a constant percentage with each doubling of the total number of units produced. Generally, an experience curve is expressed as

$$C_{CUM} = C_0 \cdot CUM^b$$

where C_{CUM} is the cost per unit as a function of output, $C_0$is the cost of the first unit produced, CUM is the cumulative production over time, and b is the experience index. For each doubling of the cumulative production ($CUM_2 = 2CUM_1$) the relative cost reduction will be

$$\frac{C_{CUM1} - C_{CUM2}}{C_{CUM1}} = 1 - 2^b$$

where $2^b$is called the progress ratio. The progress ratio is used to express the progress of cost reduction for different technologies. For example, a progress ratio of 90 percent means that costs are reduced with 10 percent each time the cumulative production is doubled.

In our analysis, for the best case wind farm to reach its grid parity, the LPC must decrease by more than 32 percent. By the means of experience curve methodology this is equivalent to progress ratio of 78 percent. As pointed out above, wind power is capital intensive. In the capital cost function, the wind turbine constitutes of 75-80 percent of the total cost. Hence, in order to see future cost decreases one must investigate the development in turbine costs. Studies on experience curves for the wind turbine industry report the progress ratio to be 92 percent for Denmark and 98 percent for Germany (Neij et al., 2003). This means that costs are expected to be reduced with between 2 and 8 percent each time the cumulative production is doubled. Therefore, even if it was the case that the cumulative production of wind power would double during a time span of 20 years, we should not expect the industry to reach its grid parity. Figure 8.2 shows the Salter-diagram for an 8 decrease in the LPC-level, still as a function of a discount rate at the 6 percentage level. Even if it was the case that the cumulative production of wind power would double during a time span of 20 years, we should not expect the industry to reach its grid parity.

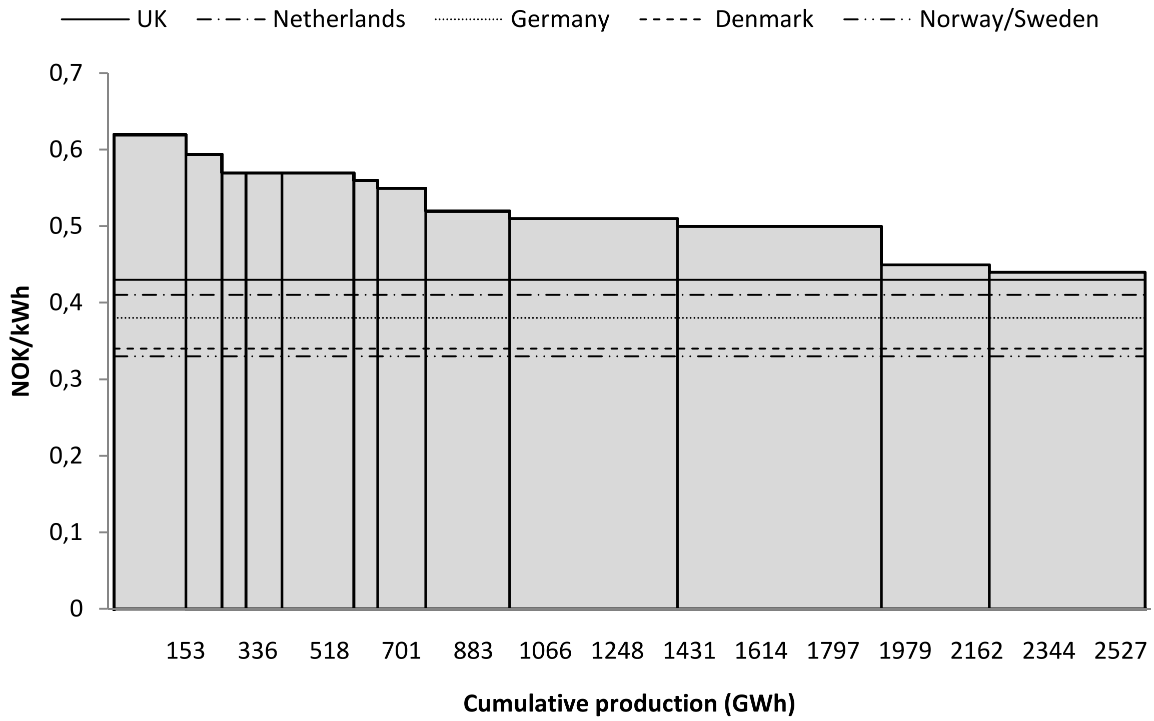

Fig. 8.2: Salter-diagram for an 8 percent decrease in the LPC-level and a discount rate of 6 percent.

9. Concluding remarks

During the last 20 years Europe has seen a rapid increase in the development of wind power. During this period total generation from wind energy has increased from 0,7 TWh to more than 100 TWH and wind power is by far the energy resource with highest relative growth rate. The large growth is largely attributed to the growing attention to environmental problems and security of supply. Especially, does the Stern-review (Stern, 2006) point out that a combination of higher carbon prices and the promotion of new renewable technology is needed in order to stabilize the emission of CO2 below 550 CO2e[11]. Concerns regarding the security of supply and environmental issues were also the underlying motivation when Norway introduced its target for the restructuring of the energy sector. Among these targets was the production of 3 TWh from wind power by 2010.

Since the long-run marginal costs of wind power generally have exceeded the market price, the development of wind power has been highly reluctant on subsidies. Several support schemes have been development, but the two most common are the feed-in tariff and direct subsidies. Norwegian wind power development has to a large extent been driven by direct subsidies. By 2009, the Norwegian wind power industry has been subsidized with more than NOK 1600 million, which has generated more than 1,7 TWh[12].

Wind power is a capital intensive energy source. Between 70-80 percent of the total cost is related to the upfront capital cost, whereas much as 40-70 percent of costs is related to operation, maintenance and fuel for conventional power technology.

The purpose of this work has been to study the so-called grid parity – the point at which the cost of electricity from wind power will equal the cost of producing electricity by traditional means without taking into consideration subsidies. The future price has been estimated for the five price regions along the Norwegian coast and the long-run marginal cost for 12 Norwegian wind farms has been calculated. The average price for Norway is estimated at 0,33 NOK/kWh. The long-run marginal cost for the 12 wind farms is calculated between 0,49 NOK/kWh and 0,71 NOK/kWh with a discount rate of 6 percent. Given stable costs, wind power will not reach its grid parity.

[11] See footnote 4 on CO2e.
[12] 700 GWh are not yet developed.

For the best case wind farm to reach its grid parity, following experience curve methodology, the progress ratio must be found to be less than or equal to 78 percent. The wind power industry is capital intensive. In the capital cost function, the wind turbine constitutes of 75-80 percent of the total. Hence, in order to see future cost decreases one must investigate the development in turbine costs. Studies on experience curves for the wind turbine industry report the progress ratio to be 92 percent for Demark and 98 percent for Germany. This means that costs are reduced with between 2 and 8 percent each time we the cumulative production is doubled. Again, we cannot conclude that Norwegian wind power will reach its grid parity within the next 15-20 years.

When compared to early feed-in schemes used in Germany from 1990 to 1997, the Norwegian subsidy regime established in 2000 seems to generate more wind power in terms of GWh during the 7 consecutive years (see Section 4.2). This thesis does not provide a thorough analysis on the topic, it has not even been the scope of the thesis. However, as the use of direct subsidies for the benefit of Norwegian wind power development continues, more data will be available and these indications should be subject for further research.

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Appendix A

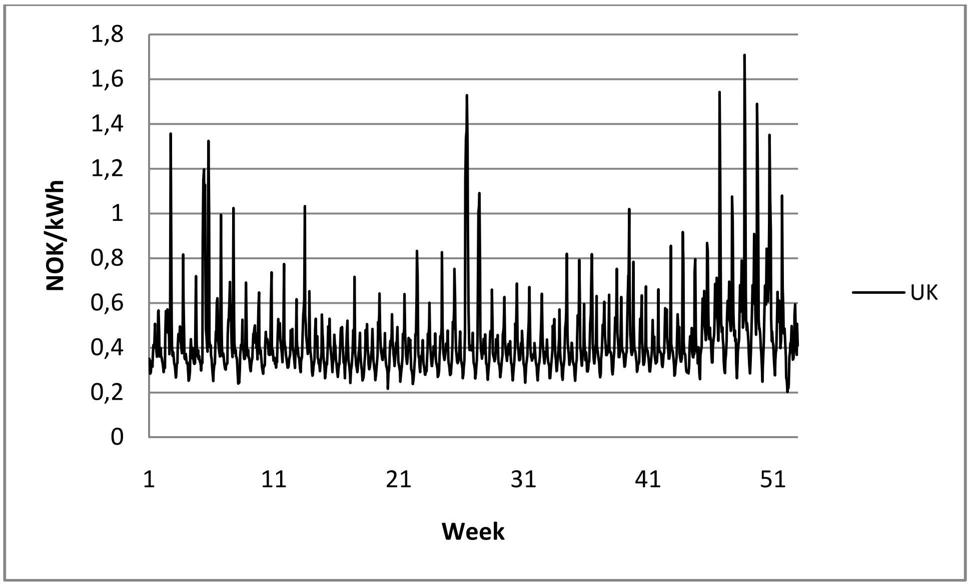

Fig. A.1: Future prices UK.

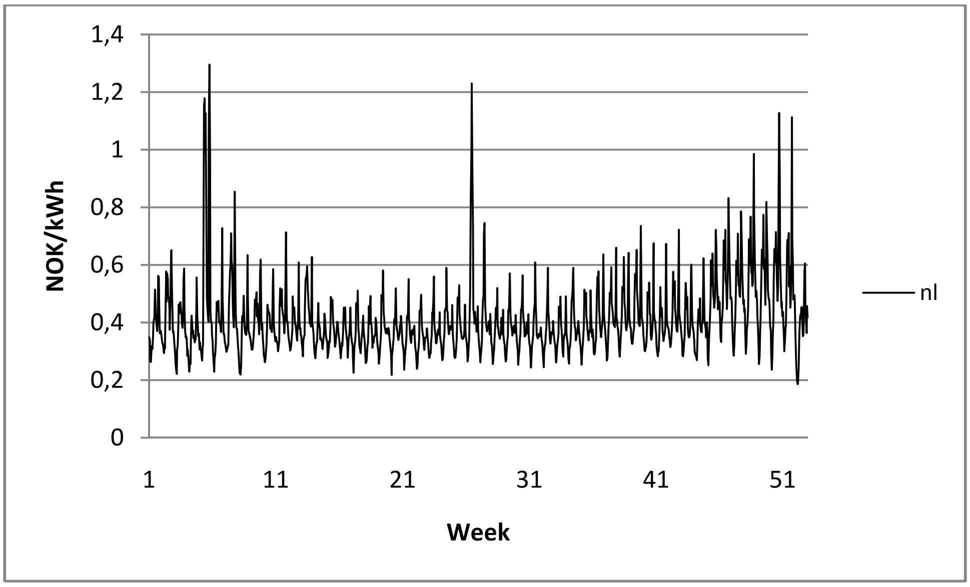

Fig. A.2: Future prices the Netherlands.

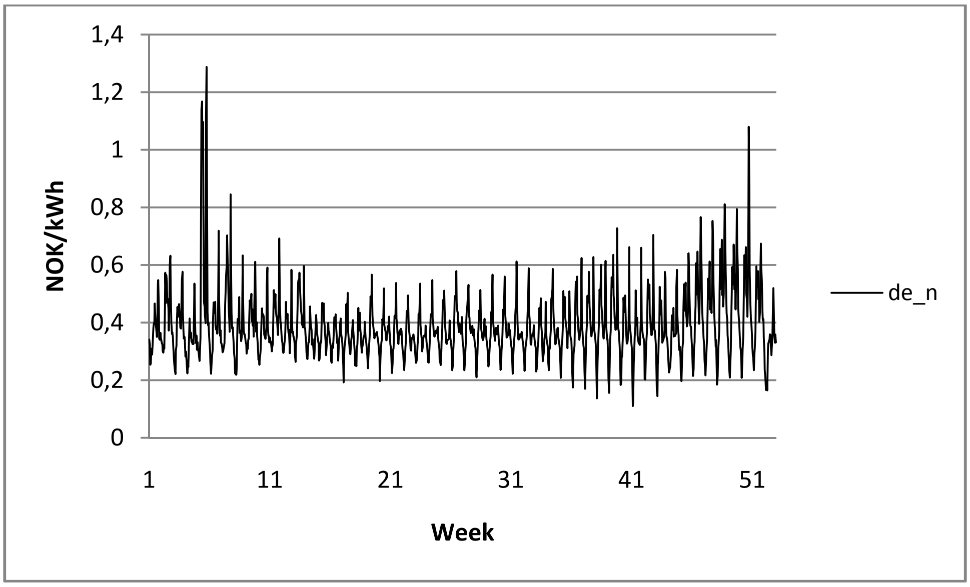

Fig.: A.3: Future prices North-Germany.

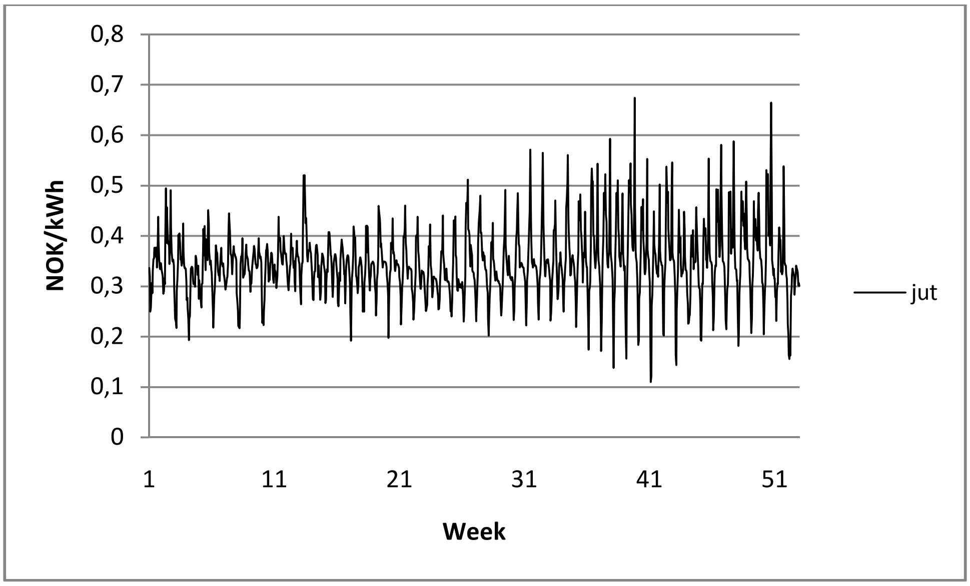

Fig. A.4: Future prices Denmark.

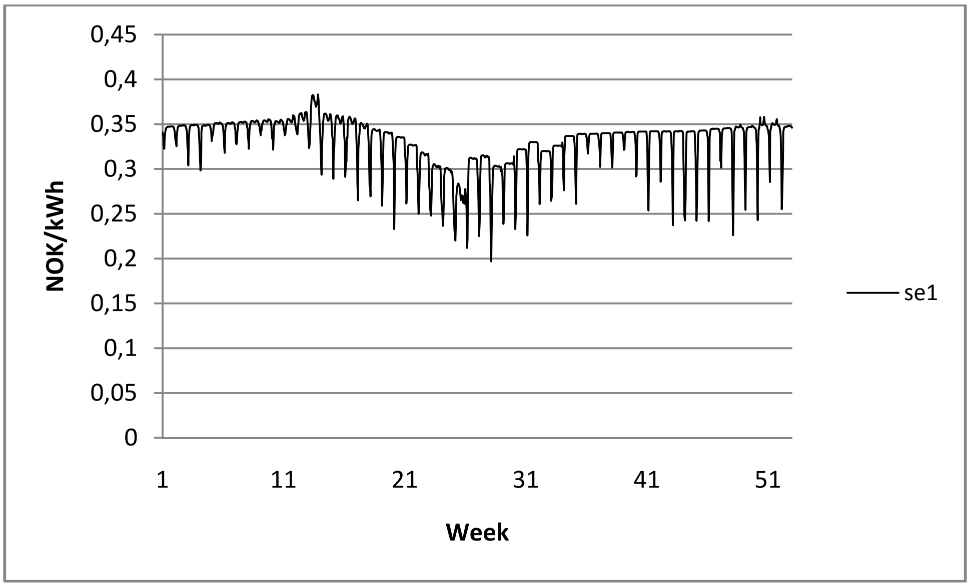

Fig.: A.5: Future prices Sweden region 1.

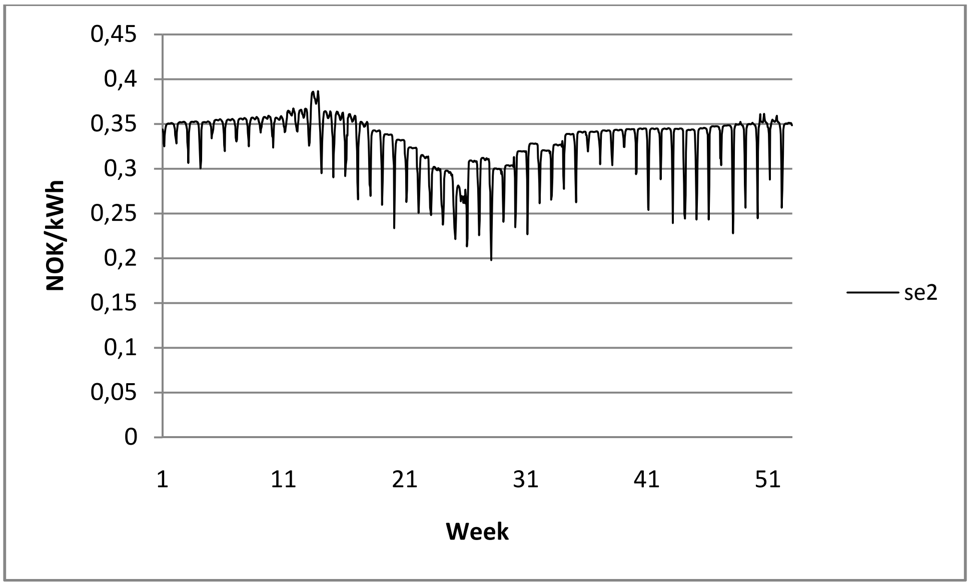

Fig. A.6: Future prices scenario Sweden region 2.

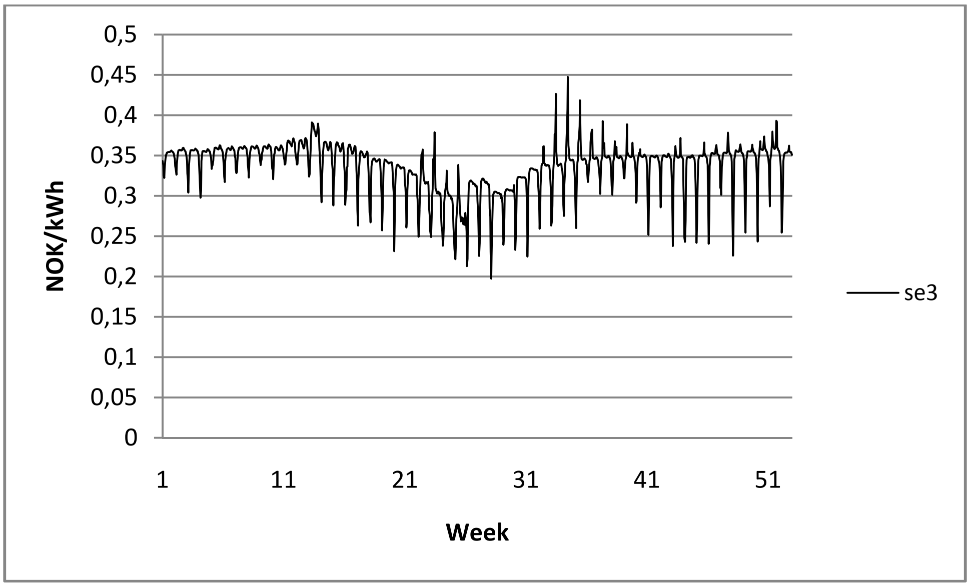

Fig. A.7: Future price scenario Sweden region 3.

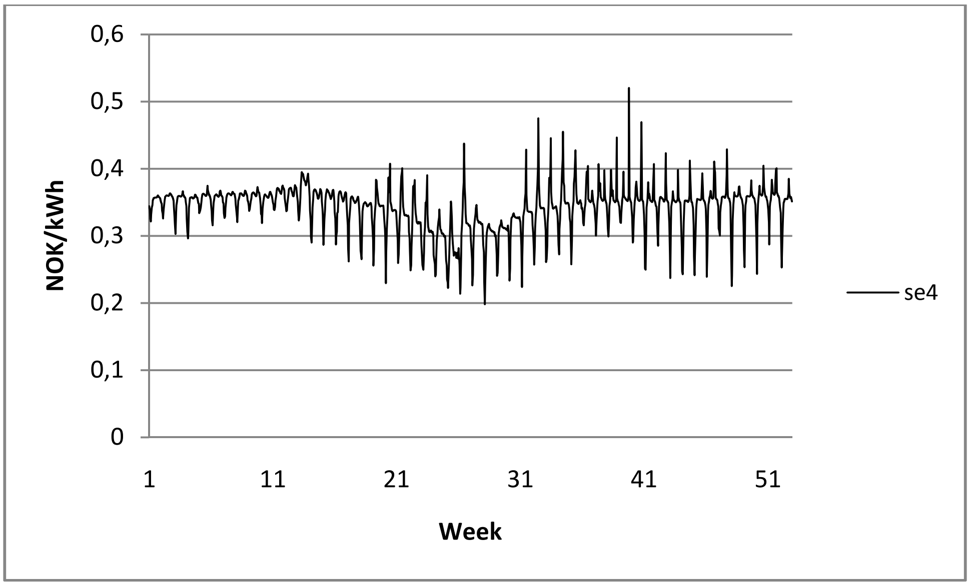

Fig. A.8: Future price scenario Sweden region 4.