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Modelling of wind power

A techno-economic analysis of wind turbine configurations

Master's thesis in Sustainable Energy Systems

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Abstract

Wind power production has increased by a hundredfold during the last twenty years and represents roughly 3 % of the total global electricity production. The recent years, technological changes in wind turbine configurations have enabled higher capacity factors for wind turbines. The aim of this work was to show the effects of different wind turbine configurations on the value of the produced electricity in current power systems, and on the role of wind power in scenarios of future power systems.

Two case studies were conducted in order to analyse the characters of wind power with different perspectives on economy and time, in Denmark and Sweden. The case studies included three models: (i) a power curve model for simulation of wind power production profiles for different wind turbine configurations, (ii) a cost model for wind turbine investment costs, for different wind turbine configurations, and (iii) a power system model, which optimizes the investments and provides the most cost-efficient composition of the electricity production technologies.

The results from the studies of the Danish and Swedish power systems show that wind turbines with lower specific power, than the traditional configurations, are more profitable and generates more value to the power systems even though they have higher levelized cost of electricity. The results shows that wind power can play a major role in future power systems with low carbon emissions. If designing the wind turbines with lower specific power than today, large wind power penetration levels of about 60 and 80 % could be cost-optimal under strict carbon emission regulations in Sweden and Denmark respectively, without interregional transmission lines or electricity storage possibilities.

Keywords: Wind power, specific power, capacity factor, cost optimization, energy system modelling, power curves, cost-optimal.

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Viktor Johansson & Ludwig Thorson, Gothenburg, June 2016

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Introduction

Electricity production from wind power has increased by an average of 25 % per year globally, between the years 1994 and 2015 (BP, 2015). During those years the total global wind power production increased a hundredfold, to exceed 700 TWh in year 2014, corresponding to roughly 3 % of the total global electricity production. In a future scenario from the International Energy Agency (2013), with a large share of renewable power, wind power is forecasted to provide 18 % of the total electricity globally in year 2050. Denmark, which is the country with the highest wind power penetration level in the world, has a target to reach 50 % of electricity production from wind power already in year 2020 (GWEC, 2015). The difficulty in utilizing high shares of wind power is the variability of wind power production. Denmark has the ability to utilize a large amount of wind power today, without shortages in the power system, due to good wind conditions and large interconnections to neighbouring countries.

A large share of wind power in the power system, makes the system complex since it is not demand following, as can be seen in Figure 1.1. There are however several solutions of how to parry the negative effects from the variability of wind power production. Some of these solutions for variation management are: regulating power, demand side management, large scale energy storage, a geographical distribution of wind turbines and transmission capacity to other regions. The need for variation management could however be reduced, by optimizing the configuration of the wind turbines for high wind power penetration levels.

Wind power technology mainly consists of three bladed turbines, common already in the early 1980's, but the technology has been improved since then (Maegaard, Krenz, & Palz, 2013). The wind turbines has been enlarged along with improvements of the electrical subsystems and control units. During the years of development, the wind turbines has increased in height, rotor diameter and generator size (Wiser & Bolinger, 2015). The increased height has made the turbines reach better wind conditions, where the wind speed is higher and more stable. The gain in generator size and rotor diameter has improved the power production for single wind turbines. The swept area has increased in higher proportions than the generator size, which together with the higher towers has led to more stable power production patterns and higher capacity factors.

The aim of this thesis is to show the effects different wind turbine configurations have on current investments, and on the role of wind power in scenarios of future power systems. This will be made to show system effects from the trend of increasing capacity factors. A wind power model will be developed in order to represent the power production from both current and future wind turbines. The model will be used to process wind speed

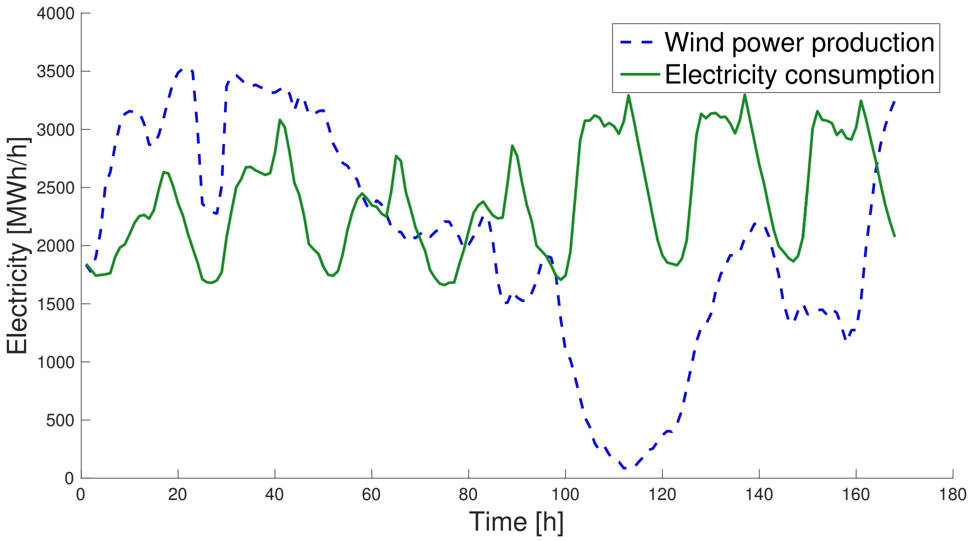

Figure 1.1: The electricity consumption and wind power production for the first week of year 2015 in bidding area DK1 in Denmark (Nord Pool AS, 2016b).

data, for different locations, into power production profiles for different wind turbine configurations. The output from the model will then be used to analyse questions regarding scenarios of future power systems and for estimations of the value of different wind turbine configurations in present markets.

This study will assess how to optimize the revenue from wind power, in order to make profitable investment decisions on the choice of wind turbine configuration. An economic comparison will be made on the turbine configuration which produces the cheapest electricity, compared to the turbine configuration which produce electricity with the highest value. The assessment will be performed on bidding areas in different countries to visualize the effects of wind power on the electricity spot price, and how different wind conditions affects the configuration of the cost-optimal wind turbine.

The study will also comprise an analysis of the role of wind power in scenarios of future power systems with low carbon emissions. The scenarios will be modelled with different accessibility to hydropower and nuclear power in order to see how possible future legislations impacts the applicability of wind power.

The study will include variations of wind turbine configurations. The parameter to be configured is mainly the rotor diameter for a constant generator capacity and hub height[1]. Variations in hub height will also be considered in the work. Data from the bidding area DK1 in western Denmark will be used to analyse a windy region with a current high wind power penetration level, and the bidding area SE3 in the middle of Sweden will be used as a less windy region with a current low wind power penetration level.

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[1] The height of the center of the wind turbine rotor.

2

Theory

The following sections describes the energy in wind, the main parts of a wind turbine, the impacts of combining wind turbines into wind farms and some economics of investments. The energy content as well as the limiting factors of how much wind that can be transformed into electrical power are explained in Section 2.1. The parts: rotor, tower and nacelle are described in Section 2.2. Section 2.3 and 2.4 include details about wind farms and economics of investments in wind turbines, respectively.

2.1 Wind energy

Wind energy can be described by the kinetic energy of the particles in the air. The energy content, E_{wind}, in a mass of air, m_{air}, is described as

$$E_{\text{wind}} = \frac{1}{2} \cdot m_{\text{air}} \cdot v^2, \tag{2.1}$$

where v is the wind speed (Kissell, 2010). Power of the wind, P_{wind}, can be described by the energy in a volume of air that passes an area, A,

$$P_{\text{wind}} = \frac{1}{2} \cdot \rho_{\text{air}} \cdot A \cdot v^3, \tag{2.2}$$

where ρ_{air} is the density of air. The density varies with the altitude and time, since it depends on the temperature and pressure. The average density at ground level of 1.225 kg/m^3 is however widely used at the hub height of wind turbines, since the variations are small (Carrillo, Montaño, Cidrás, & Díaz-Dorado, 2013). The theory of how to model the conversion of wind power into electricity and how to process wind data, is presented in Section 2.1.1 and 2.1.2, respectively.

2.1.1 Wind power modelling

The amount of energy which can be harvested by a wind turbine is expressed by multiplying the power of the wind with the coefficient of performance, C_P. C_P is depending on the blade design as well as the number of blades, and is a function of the blade pitch angle and the tip speed ratio, λ, which is the ratio between the blade tip speed and the wind speed (M. Ragheb & Ragheb, 2011). The C_P value increases with λ until the optimal ratio around 7, which is the point where the negative effects from a high tip speed becomes major to the positive effects. The positive effects from a high λ are good breaking of the wind and high efficiency of the generator. The negative effects are increased noise, blade erosion, drag losses and increased flow around the wind turbine instead of through it. If all the kinetic energy in the wind was to be extracted, the wind would stop completely and no wind would be able to pass through the wind turbine. Therefore, according to Betz law, the theoretical maximum value of C_P is 0.593 (Dixon & Hall, 2014). In reality three bladed wind turbines normally have a maximum C_P value in the span of 0.4 to 0.5, which sometimes also includes mechanical and electrical losses (Carrillo et al., 2013).

A power curve describes the power production of a wind turbine as a function of the wind speed. Power curves could either be provided by the wind turbine manufacturer or be approximated. A real wind power curve, P_{real}, is described as a function of $C_P(v)$, which varies with the wind speed. The approximate cubic power function, P_{cub}, is according to Carrillo et al. (2013) a widely used simplified model of the power curve, even though it slightly overestimate the electricity production. The simplification is to set the C_P value constant at its maximum value, $C_{\text{P,max}}$, for all wind speeds. The difference between a real and an approximate cubic power curve can be seen in Figure 2.1, and the equations for the curves can be seen in Equations 2.3 and 2.4, respectively.

$$P_{\text{real}}(v) = \begin{cases} 0, & \text{if } v_{\text{ci}} > v \text{ or } v > v_{\text{co}}, \\ \frac{1}{2} \cdot C_P(v) \cdot \rho_{\text{air}} \cdot A \cdot v^3, & \text{if } v_{\text{co}} \geq v \geq v_{\text{ci}}, \end{cases} \tag{2.3}$$

$$P_{\text{cub}}(v) = \begin{cases} 0, & \text{if } v_{\text{ci}} > v \text{ or } v > v_{\text{co}}, \\ \frac{1}{2} \cdot C_{\text{P,max}} \cdot \rho_{\text{air}} \cdot A \cdot v^3, & \text{if } v_r \geq v \geq v_{\text{ci}}, \\ P_r, & \text{if } v_{\text{co}} \geq v \geq v_r, \end{cases} \tag{2.4}$$

where P_r is the rated power, v_r is the rated wind speed, v_{ci} is the cut-in wind speed and v_{co} is the cut-out wind speed. Rated power is the maximum capacity of a wind turbine and rated wind speed is the wind speed at which rated power is obtained. The cut-in and cut-out wind speeds are usually around 3 m/s and 25 m/s, respectively. However, the cut-in speed is sometimes increased, due to regulations for protection of animals, such as bats (Carrillo et al., 2013), (Rydell et al., 2012). Both formulas show that the wind turbines are turned off for wind speeds lower than the cut-in wind speed or higher than the cut-out wind speed. In Equations 2.3 and 2.4, the turbine is running on rated power for wind speeds higher than the rated wind speed. However when modelling the real power curve, the variable C_P is limiting the power production at the rated power.

In order to categorizing wind turbines with different rated power and rotor diameters, the term specific power, P_s, could be used. Specific power is the rated power divided by the swept area (Wiser & Bolinger, 2015). Two turbines with the same specific power will produce the same power production pattern at the same hub height and location, but not the same amount of electricity, unless they also have the same rated power. A lower specific power results in a higher capacity factor, since it reaches rated power at a lower wind speed. Figure 2.2 shows how the specific power varies with the rotor diameter for turbines with fixed rated power. The hub height is another important factor for the electricity production from wind turbines, since the wind speed generally increases with height.

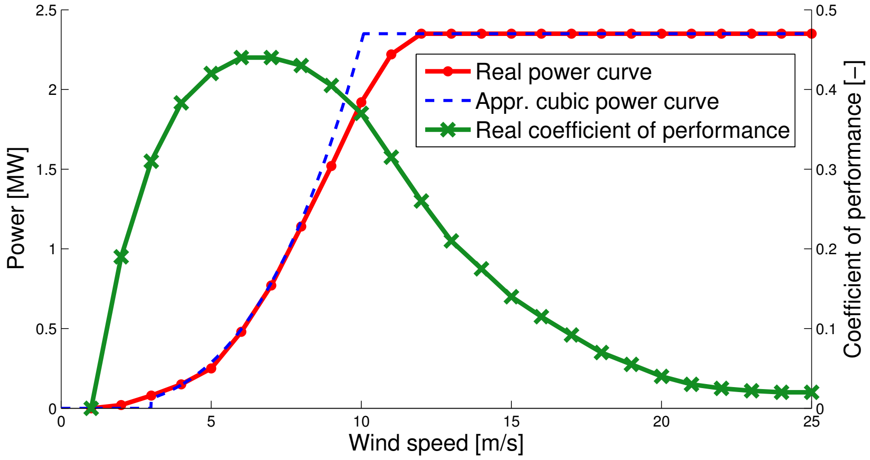

Figure 2.1: The approximate cubic power curve and the real power curve with its associated C_P curve for an Enercon E-103 EP2 / 2.35 MW wind turbine (Enercon, 2016a).

2.1.2 Wind resource

In order to calculate the wind power production from historical wind data, a continuous function of the wind speed, at the hub height, is needed. In order to get accurate measurements of the wind speed, wind power companies set up one or several measuring masts, with anemometers at different heights, before deciding to install wind turbines (Fahleson, 2012). To modify the measured wind data to the desired altitude, the wind shear function is used. The wind shear function is described by

$$\frac{v_2}{v_1} = \left(\frac{h_2 - h_{\text{disp}}}{h_1 - h_{\text{disp}}}\right)^{\alpha}, \tag{2.5}$$

where v_1 is the measured wind speed at the height h_1, v_2 is the unknown wind speed at the hub height h_2, h_{disp} is the displacement height, which is the height at which the wind speed is projected to be zero for modelling purposes, and α is the wind shear exponent, which is depending on the ground roughness (Thapar, Agnihotri, & Sethi, 2011).

2.2 Wind turbine components

The horizontal three bladed turbine has been the dominant design since the breakthrough of wind power in the early 1980s (Maegaard et al., 2013). The size of the turbine has increased substantially over the years and the components are continuously improving. In this section short descriptions of the main parts of a wind turbine, illustrated in Figure 2.3, are presented.

2.2.1 Tower

The tower of a large wind turbine is usually made by circular sections of rolled steel which are mounted on top of each other and joined together with bolts (Engström, Lyrner, Hassanzadeh, Stalin, & Johansson, 2010). The nacelle, combined with the rotor, is mounted on top of the tower, to take advantage of the best possible wind conditions. The tower height is limited by the ability to transport the wide bottom segment under bridges.

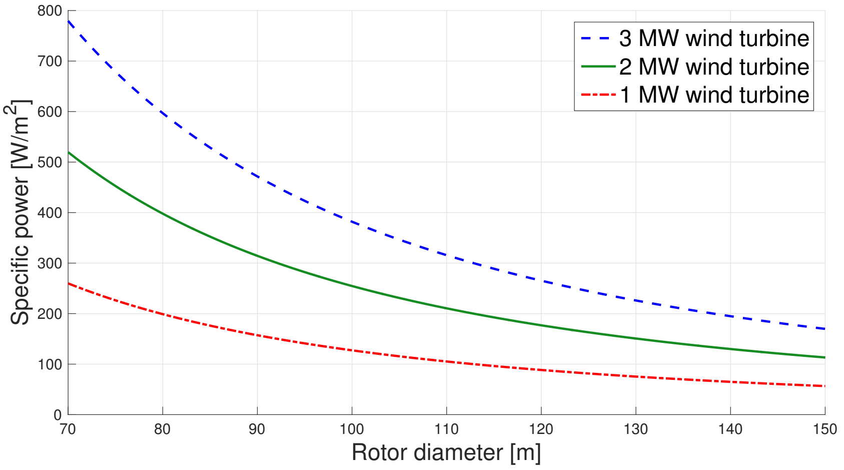

Figure 2.2: The specific power as a function of the rotor diameter, for wind turbines with rated power of 1, 2 and 3 MW.

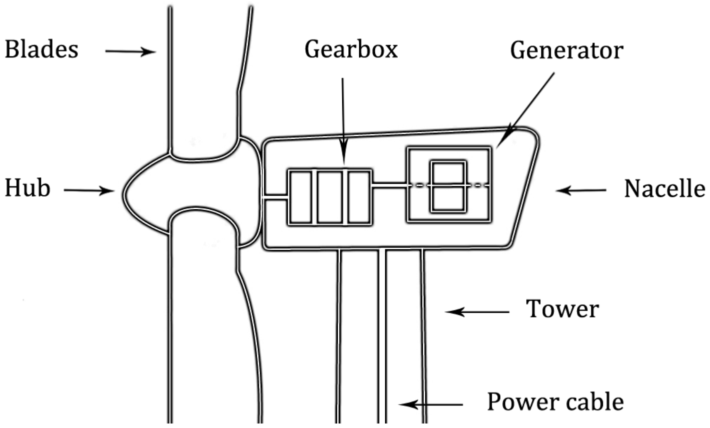

Figure 2.3: The main parts of a wind turbine.

On the inside of the tower, the power cable is hanging from the nacelle and is connected via a transformer, located on the ground, to the grid. The tower is one of the most expensive parts and according to Moné, Stehly, Maples, and Settle (2015), the cost for towers in land-based projects is on average about 13 % of the total cost. The size of the tower is dependent on the hub height, the rotor diameter and the size of the generator. To support the structure, a foundation is build below the tower. The foundation is made of reinforced concrete, where the size of the foundation is depending on the size of the turbine and the wind classification of the site.

2.2.2 Rotor

The rotor is the assembly of the blades mounted on the hub. The blades have similar design as airplane wings and uses the lift force to establish the rotation (Jensen & Branner, 2013). The blades are typically made of composite materials, which allows for a high strength-to-weight ratio (Abdelal & Donaldson, 2013). The blades are of different sizes for different turbine models, ranging up to 68.5 m for onshore turbines, which corresponds to a rotor diameter of 140 m when including the hub (Senvion, 2015). The rotational speed is limited at the tip speed of about 80 m/s to keep the noise level down (Burton, Jenkins, Sharpe, & Bossanyi, 2011). The blade size is limited, due to difficulty of transporting long blades on roads (Cotrell et al., 2014). The length problem could, however, be solved by segmenting the blades, which on the other hand makes the construction more expensive.

2.2.3 Nacelle

The nacelle is installed on the top of the tower, and contains the gearbox, low- and high-speed shafts, mainframe and the generator (Bruhn, Lorensson, & Svensson, 2009). The most common way to configure the turbine is to have a 3-stage gearbox between the rotor and the generator, however in recent years the use of direct drive has increased, since it is decreasing the number of parts needed.

2.3 Wind farm

Wind farms are more cost-efficient compared to installing individual wind turbines, due to economy of scale. Costs for transportation, planning, construction of the parts, and the power electronics for the connection of wind turbines to the grid becomes cheaper in large scale (Burton et al., 2011). The negative effect of wind farms is the loss of production due to wake effects.

When wind passes through a wind turbine, a linearly increasing, cone shaped wake is created behind it, due to the energy extraction (González-Longatt, Wall, & Terzija, 2012). There are two different zones, behind each wind turbine, which are defining the wake effect (Vermeer, Sørensen, & Crespo, 2003). The first is the near wake zone and is defined as the area directly behind the rotor and up to approximately one rotor diameter downstream of the turbine. The second zone is the far wake zone, which is located beyond the near wake. The near wake zone is mainly affecting the coefficient of performance and the process of extracting power. The far wake zone is affecting the other wind turbines inside a wind farm, and it is therefore the important zone when deciding wind turbine spacing, the distance between the wind turbines, for wind farm design (Vermeer et al., 2003). Due to wake effect, commercial wind farms have a turbine spacing of around 7-10 rotor diameters (Bruhn et al., 2009).

2.4 Economics

When analyzing investments with future cash flows, the discount rate and economic lifetime are two important factors. The discount rate, r, is the interest rate which determines the present value of future cash flow. Except from leveling out the inflation, discount rate also includes risks and uncertainties of the investment. The discount rate and the economic lifetime, y, are used, together with the total investment cost, C_{INV}, to derive the annual investment cost, C_{inv},

$$C_{\text{inv}} = C_{\text{INV}} \cdot \frac{r \cdot (1+r)^y}{(1+r)^y - 1}. \tag{2.6}$$

The levelized cost of electricity from a wind turbine, $LCOE$, expresses an equally shared production cost per unit of electricity produced by the turbine. The expression for LCOE is

$$LCOE = C_{\text{varO\&M}} + \frac{C_{\text{inv}} + C_{\text{fixO\&M}}}{AEP}, \tag{2.7}$$

where AEP is the annual electricity production, $C_{\text{varO\&M}}$ is the variable operation and maintenance (O&M) costs, $C_{\text{fixO\&M}}$ is the fixed O&M costs and there are no fuel costs for wind power. The basis for investment decisions can be made more complex by including the variations in spot price. The yearly net profit, $Profit_{net}$, from wind power production could then be calculated with Equation 2.8, this is however without taking into account regulating costs, taxes, other costs or subsidies.

$$Profit_{net} = \sum_{t=1}^{8760} \left(\Big(P_{\text{spot}}(t) - C_{\text{varO\&M}} \Big) \cdot p_{\text{wind}}(t) \right) - C_{\text{inv}} - C_{\text{fixO\&M}}, \tag{2.8}$$

where $P_{\text{spot}}(t)$ is the spot price at hour t, $p_{\text{wind}}(t)$ is the electricity production at hour t and 8760 is the number of hours in a year. The profitability of an investment can be measured by the yearly return on investment, ROI,

$$ROI = \frac{Profit_{net}}{C_{inv}}. \tag{2.9}$$

3

Methods

The method is comprised by two case studies and three models. Explanations of the two case studies: a wind value study and a power system study are presented in Section 3.1. The two case studies are conducted in order to analyse questions regarding both estimations of the value of different wind turbine configurations in present markets and the role of wind power in scenarios of future power systems. Section 3.2 include the description of three models: (i) a power curve model for simulation of wind power production profiles for different wind turbine configurations, (ii) a cost model for wind turbine investment costs, for different wind turbine configurations, and (iii) a power system model, which optimizes the investments and provides the most cost-efficient composition of the electricity production technologies. Section 3.3 describe the input data. The reports by Wiser and Bolinger (2015) and Moné et al. (2015) use 2014 US dollars as currency, the exchange rate is set to 0.75 €/\$, which was the average exchange rate year 2014 (X-RATES, 2016).

3.1 Case studies

Two case studies are conducted in order to analyse the characters of wind power with different perspectives on economy and time. The wind value study is made on current power systems, to analyse the value of produced electricity from wind power, and the power system study is focused on scenarios of future power systems, with a social perspective. Both studies are based on wind speed and power market data from Denmark and Sweden, more specifically the bidding areas DK1 and SE3 which are seen in Figure 3.1. The wind turbine configurations included in both studies have specific power between 247 W/m^2 and 110 W/m^2. The upper limit represents a 1.94 MW wind turbine with a rotor diameter of 100 m (the average installed wind turbine configuration in USA, year 2014) and the lower limit represents a 1.94 MW wind turbine with a rotor diameter of 150 m (Wiser & Bolinger, 2015).

The aim of the wind value study is to compare different sites within the bidding areas, to show potential effects on the optimal wind turbine configuration for different wind speed profiles. The wind value study analyses effects on the choice of wind turbine configuration, based on the impact from wind power on the spot price. The analysis examines which wind turbine configuration produces the largest return on investment (ROI). The study is made on the two bidding areas, DK1 and SE3, to represent areas with different wind conditions and wind power penetration levels, where the sites within the areas are represented by MERRA wind data points (Global Modeling and Assimilation Office (GMAO), 2016). Effects on the optimal wind turbine configuration, which depends on the wind power penetration levels and wind speed profiles, within the different bidding areas, is also

Figure 3.1: A map of the Nord Pool AS (2016a) bidding areas, where DK1 is seen in western Denmark and SE3 is seen as one of the areas in the center of Sweden.

analysed.

Wind power production is calculated for several wind turbine configurations, from historical wind data, with a power curve model, further explained in Section 3.2.1. The revenue from selling the produced wind power, at the historical spot price of the associated hour and bidding area is calculated. The costs for the wind turbines, described in Section 3.2.2, is combined with the revenue, in order to derive the ROI and LCOE for each wind turbine configuration.

The power system study analyse the effect of different wind turbine configurations in scenarios of future power systems. The study also analyses the possible role of wind power in the system, depending on the turbine configuration and the yearly average wind speed of the area. The analysis optimize the power system for a set of wind turbine configurations together with other power technologies, to study the cost-optimal power system composition, with a carbon emission reduction of 99 % compared to the year 1990 level. The two bidding areas, DK1 and SE3, are modelled to represent a windy region and a less windy region. The results are produced with the power system model, presented in Section 3.2.3, including wind power production profiles and investment costs from the models presented in Section 3.2.1 and 3.2.2, respectively.

3.2 Models

Three models are used to perform the two case studies, a power curve model, a cost model and a power system model. The power curve model, which is converting wind speed data to wind power in the two case studies, is presented in Section 3.2.1. The cost model which is used to describe the investment costs in both cases, is described in Section 3.2.2. The power system model, which is a linear programing model presented in Section 3.2.3, is used for the power system study.

3.2.1 Power curve model

Power curves are modelled with a modification of the approximate cubic power curve. The modification is made in order to better match the real Enercon (2016b) power curves around the rated wind speed. In the ordinary approximate cubic power function, the C_P value is set to its maximum value from cut-in wind speed until it reaches rated power. In this modification, the C_P value linearly decreases to one third of $C_{P,max}$ in a span of 7 m/s. The decline starts 2 m/s before the rated wind speed, calculated with $C_{P,max}$, and the curve is no longer C_P dependent when it reaches rated power. A modelled power curve is seen in Figure 3.2, which can be compared to the approximate cubic power curve in Figure 2.1.

An aggregation of power curves is made to account for wind farm and regional effects. Internal losses for wind farms, which represents wake effects, and external losses which represents availability and electrical losses, are included. The external losses are assumed to affects the total output at all wind speeds with an equal percentage. The internal losses are assumed to affect the power output until it reaches rated power. The variations within a MERRA wind data point is accounted for by a normal distribution of wind speed input data (Olauson & Bergkvist, 2015). The wind data is extrapolated to desired heights with the wind shear function, described in Equation 2.5. The matlab code of the power curve model is seen in Appendix B.1

3.2.2 Cost model

A cost model for the investment and installation cost of wind turbines is developed from costs presented by Moné et al. (2015). The model is a polynomial regression of the wind turbine costs for five different wind turbine configurations with diameters in the span of 87.2 m to 111.1 m. The model and the data points from which it origins are seen in Figure 3.3. The wind turbine investment and installation cost model, $C_{INV}(D)$, is a function of the rotor diameter, D, for a generator size of 1.94 MW and hub height of 80 m, seen in Equation 3.1. The rated power is the average value for new onshore installations in USA 2014 and the hub height of 80 m is the height used in the Moné et al. (2015) report. Engström et al. (2010) add 29 % on the investment costs when increasing the hub height from 80 to 125 m, in this report the 29 % is used for increasing the hub height to 120 m, which is not included in Equation 3.1.

$$C_{INV}(D) = 0.0587 \cdot D^2 - 4.93 \cdot D + 1140. \qquad [€/MW] \tag{3.1}$$

3.2.3 Power system model

The power system model is a simplified version of the model developed by Göransson, Goop, Odenberger, and Johnson (n.d.). It uses linear optimization to achieve the minimal system cost, with a carbon emission reduction of 99 % compared to the year 1990 level, where the constraints and objectives are represented by linear equations. The objective of the model is to minimize the investment and dispatch costs for a bidding area in one year, with a temporal resolution of one hour. The model contains constraints for start-up and ramping times. It has has perfect transmission within the bidding area, without interconnections to other areas. The model generates an optimal system composition without any

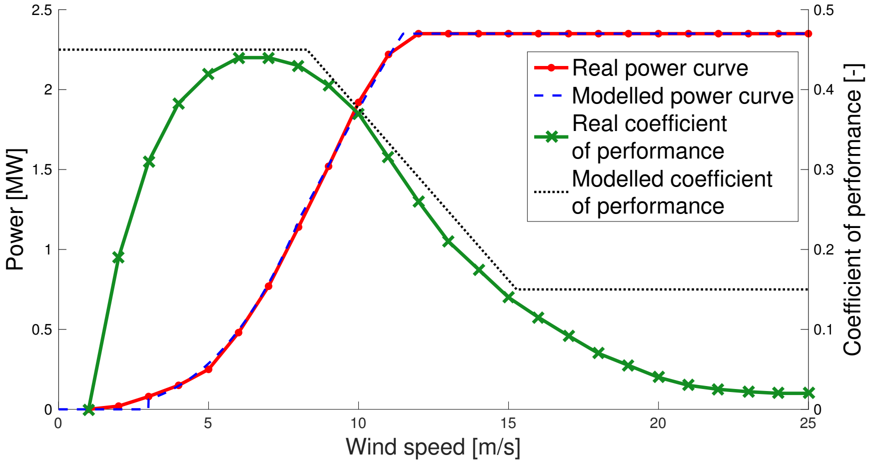

Figure 3.2: The modelled power curve with its associated modelled C_P curve and the real power curve with its associated C_P curve for an Enercon E-103 EP2 / 2.35 MW wind turbine (Enercon, 2016a).

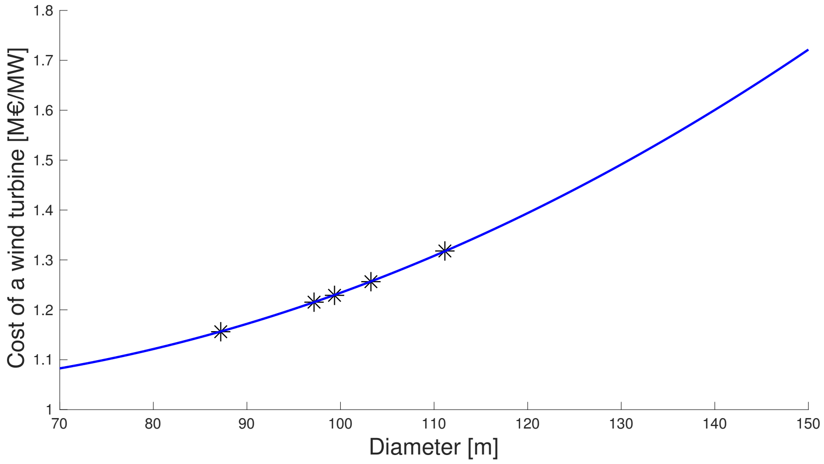

Figure 3.3: The modelled cost for 1.94 MW wind turbines with diameters ranging from 70 to 150 meters and a hub height of 80 m. The stars represents the data points from which the cost model origins. The the wind turbine configurations represents specific powers from 504 W/m^2, for the smallest diameter, to 110 W/m^2, for the largest diameter.

pre-existing power plants, also known as a green field model. Several power technologies: biogas CCGT (combined cycle gas turbine), biogas GT (gas turbine), biomass, hard coal CCS[1], hard coal with biomass CCS, hydropower with storage, natural gas (NG) CCGT, nuclear power and wind power are modelled with current costs and predicted learning rates in order to let the model find the optimal system composition for year 2050. For detailed information of the equations used in the model see Appendix A.1, and for technology and fuel properties see Appendix A.2. The wind power profiles, for different turbine configurations, are generated in the power curve model, described in Section 3.2.1, with costs from the cost model, described in Section 3.2.2.

3.3 Input data and assumptions

This section contains explanations of the data and the assumptions used in the two case studies. Historical wind speed and power market data, presented in Section 3.3.1, is used as input to the wind power production calculations and the economical calculations. Wind power parameters and other power technologies for system modelling are presented in Section 3.3.2 and 3.3.3, respectively. Processing of the data from Section 3.3.1 into comparative key figures, is presented in Section 3.3.4. The key figures are used for comparisons between current power systems and the results from the case studies.

3.3.1 Historical wind speed and power market data

The historical wind speed data is used to calculate wind power production for different wind speed profiles in the power curve model and the power market data is used for economical calculations. All historical data have the temporal resolution of one hour. The data sets: consumption, elspot prices, production and wind power are retrieved from Nord Pool AS (2016b), for the years 2013 to 2015 in the bidding areas DK1 and SE3.

The electricity spot price and wind power production in DK1 for a part of year 2013, can be seen in Figure 3.4. Both the spot price and the wind power production have large variations and from Figure 3.4 it is difficult to see any possible correlations between the parameters. To find a potential correlation, an electricity spot price-duration curve is made for DK1 year 2013, and it is seen together with the associated wind power production in Figure 3.5. The wind power production is formed with a moving average[2], from subsets of 200 data points. The same figure as for DK1, but for SE3 in year 2015, is seen in Figure 3.6. In DK1, an inverse relation can be observed between the spot price and the wind power production, where the price is low when the production is high and vice versa. In SE3, no clear relation is visible, except from the wind production being low when the price is high. The difference in relation between the regions is shown with the wind value factor, which describes the value of electricity from wind power compared to the average electricity price. Wind power gets paid about 10 - 15 % less than average electricity in DK1 during the years 2013 to 2015, and about 3 % less than average electricity in SE3 during year 2015.

The wind data used is reanalysis data, with the spatial resolution of 0.5 degrees longitude

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[1] Carbon capture and storage, a method to reduce the carbon emissions to the atmosphere, for thermal power production technologies.

[2] The average values for subsets of N values. The first average value is the average of $n_1 + n_2 + ... + n_N$, the second average value is the average of $n_2 + n_3 + ... + n_{N+1}$ and so on. It is used for smoothing curves.

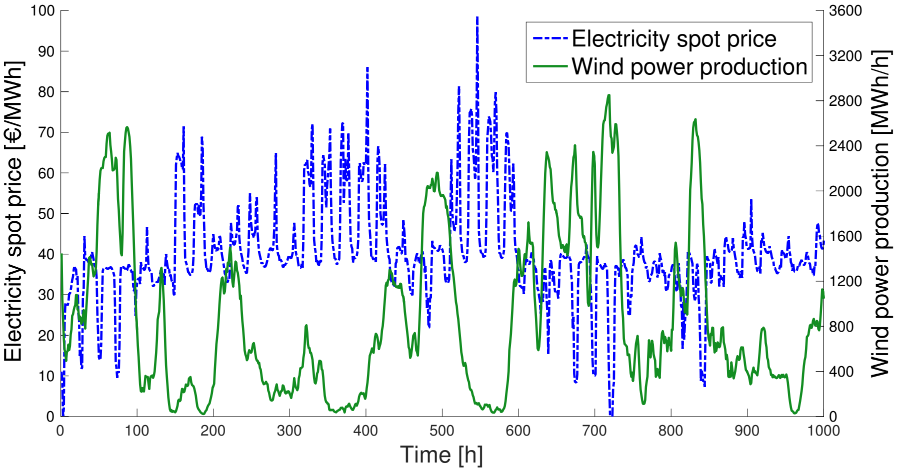

Figure 3.4: The electricity spot price and the corresponding wind power production in DK1 for the first 1000 hours during year 2013.

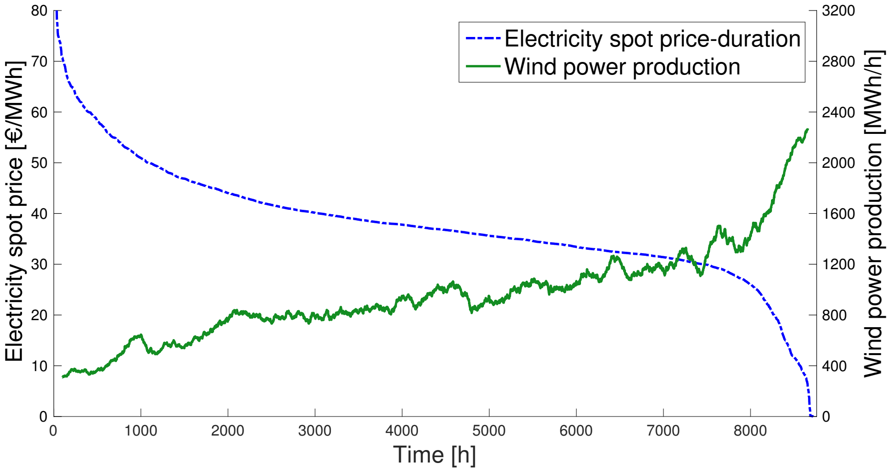

Figure 3.5: The electricity spot price-duration curve in DK1 for year 2013, with the moving average of 200 data points of the corresponding wind power production. The left y-axis is cut at 0 and 80 €/MWh, but the lowest and the highest values can be seen in Table 3.1.

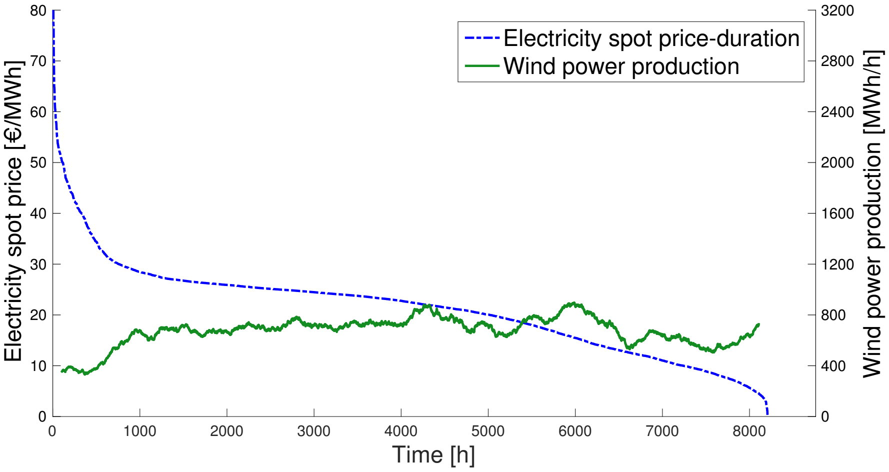

Figure 3.6: The electricity spot price-duration curve in SE3 for year 2015, with the moving average of 200 data points of the corresponding wind power production. The y-axis is cut at 80 €/MWh, but the highest value can be seen in Table 3.1.

and 0.67 degrees latitude. The data contains wind speeds at 2 and 10 meters above displacement height as well as at 50 meters above ground (Global Modeling and Assimilation Office (GMAO), 2016). The measurements at 10 meters above displacement height and 50 meters above ground level are used as references values in the wind shear extrapolation. Wind data was analysed for the years 2001 to 2015. Year 2013 was found to the be an average windy year, the wind speed profile of year 2013 was therefore used in the power system study. The years 2013 to 2015 are used in the wind value study due to the accessibility of power market data for the same years.

3.3.2 Wind power parameters

In the power curve model, several parameters are determined. $C_{P,max}$ is set to 0.45, which is a middle value in the ordinary span, and the density of air is set constant at 1.225 kg/m^3 for all heights. The cut-in and cut-out speeds are set to 3 and 25 m/s, respectively, and the wind speeds are normalized around the average wind speed, with a standard deviation of 1 m/s for the regional aggregation.

Data from Energistyrelsen (2016) is used to find the installed capacity and average configuration of wind power in the region DK1, with a daily resolution. The wind power has reached a maximum of 94 % of its installed capacity, during the years 2013 to 2015 (Nord Pool AS, 2016b). The external losses are therefore set to 6 %. Internal losses are set to 11.5 %, in order to make the total losses 16.7 % as in Moné et al. (2015). The running cost is set to 7.5 €/MWh, the economic lifetime is set to the technical lifetime of 20 years and discount rate for the wind value study is set to 8.7 % (Wiser & Bolinger, 2015), (Moné et al., 2015).

3.3.3 Power technologies for system modelling

In the power system model, a wide range of other power technologies than wind power are used to model the power system. Descriptions of the different technologies which includes cost, economical lifetime, and other technological specific characteristics are presented in Appendix A.2. The discount rate used in the power system model is 5 %, which differs from the wind value study, to model the benefit from the societal perspective. The model neither include solar power nor subsides for wind power. To preform the linear optimization of the power system, GAMS (General Algebraic Modelling System), a modelling tool for mathematical programming and optimization, is used (GAMS, 2016). The access to hydropower in the region SE3 is assumed to 7.0 GW with a capacity factor of 52.5 %, which was the maximum transmission capacity and capacity factor of the transmission lines from bidding area SE2 to SE3 year 2015.

3.3.4 Comparison data

Several key figures are calculated for comparison to the results of the two case studies.The key figures for DK1 and SE3, for the years 2013 to 2015, are seen in Table 3.1. Historical wind power production data for SE3 is only available from the 24th of Jan 2015 to the 31st of Dec 2015, some key figures are therefore only available for year 2015.

Wind power capacity is the total installed capacity in the end of the year (Energistyrelsen, 2016). In the case of SE3, the installed wind power capacity was only available from Corbetta, Mbistrova, and Ho (2016) for entire Sweden, and was therefore calculated by assuming that the highest hourly wind power production in each Swedish bidding area was equally close to the maximum capacity. The lowest and highest hourly wind power production are the minimum and maximum amount of the installed wind power capacity that was producing power during one hour. Yearly average wind speed at 80 m is the modelled average wind speed for the entire bidding area.

The capacity factor was calculated from the wind power production and the wind power capacity. Wind power penetration level is the share of the yearly power consumption, covered by wind power production. The highest hourly wind power penetration is a measure of the largest electricity production of wind power, compared to the electricity consumption for one hour. The lowest and highest spot prices are the lowest and highest hourly price of electricity during the year. The wind value factor is the weighted yearly average spot price for wind power, divided by the yearly average spot price.

Table 3.1: Key figures for the wind power production and the power market in DK1 and SE3 for the years 2013 to 2015.

	DK1			SE3		
	2013	2014	2015	2013	2014	2015
Yearly average spot price [€/MWh]	39.0	30.7	22.9	39.3	31.5	21.4
Yearly wind power production [TWh/h]	8.5	10.3	10.8	-	-	5.9
Wind power capacity [MW]	3731	3810	4005	-	-	2083
Lowest hourly wind power production [%]	0.2	-0.1	0.0	-	-	0.2
Highest hourly wind power production [%]	94.3	94.2	93.5	-	-	87.8
Capacity factor [%]	28.6	31.3	31.7	-	-	32.2
Wind power penetration level [%]	42.5	51.1	54.4	-	-	7.0
Highest hourly wind power penetration [%]	193.7	182.5	196.6	-	-	24.1
Yearly average wind speed at 80 m [m/s]	8.08	8.27	8.78	5.20	5.13	5.64
Lowest hourly spot price [€/MWh]	-62.0	-60.3	-31.4	1.4	0.6	0.3
Highest hourly spot price [€/MWh]	2000	160.0	99.8	109.5	105.4	150.1
Wind value factor [%]	85.7	88.4	85.9	-	-	96.9

4

Results

Key findings from the wind value study show that the optimal wind turbine configuration has a specific power of about 15 to 20 W/m^2 less than the specific power of the minimized LCOE configuration. This is due to the higher wind value factor since the wind turbines with low specific power make better use of the low wind speeds, when the electricity price is high, compared to wind turbines with high specific power. In the power system study, the 110 W/m^2 configuration results in the highest cost-optimal wind power penetration levels for all scenarios. The results from the wind value study and the power system study are further described in Section 4.1 and 4.2, respectively.

4.1 The wind value study

This study assesses how to optimize the revenue from wind power, in order to make profitable investment decisions through the choice of wind turbine configuration. A decrease in specific power increases electricity production per unit of installed capacity as well as wind value factor, which is the average payment for produced electricity from wind turbines, but comes at the price of an increased investment cost per unit capacity. The wind value factor as a function of varying specific power, for one site in DK1 during year 2013 can be seen in Figure 4.1. The figure also shows the ROI curve, from which a comparison of the turbine configurations for the maximum ROI and the minimized LCOE can be made. In the case of minimizing LCOE of the wind turbines, the electricity production and investment cost are optimized without optimizing the income. When the turbine configuration is optimized for ROI, the specific power is lower than in the case of minimized LCOE. The optimal specific power is 146 and 164 W/m^2, for a site with yearly average wind speed of 7.9 m/s, for the maximized ROI and minimized LCOE turbine configurations, respectively. The maximized ROI is -14.9 and about 0.3 percentage points lower for the configuration with minimized LCOE. The maximized ROI is negative because of low electricity prices and would need subsides in order to be profitable. The wind value factor increases from 0.889 to 0.926 when decreasing the specific power from 247 to 110 W/m^2, for this site in DK1 year 2013.

Wind power production, as electricity production-duration curves, for three different wind turbine configurations at a specific site, are seen in Figure 4.2. A lower specific power increases the normalized power production and thereby the capacity factor, as seen in Figure 4.3. The capacity factor increase from 29 to 62 % from the highest to lowest specific power, which are represented by rotor diameters of 70 and 150 m, respectively.

The maximized ROI is plotted for the yearly average wind speed at all sites, in Figure 4.4.

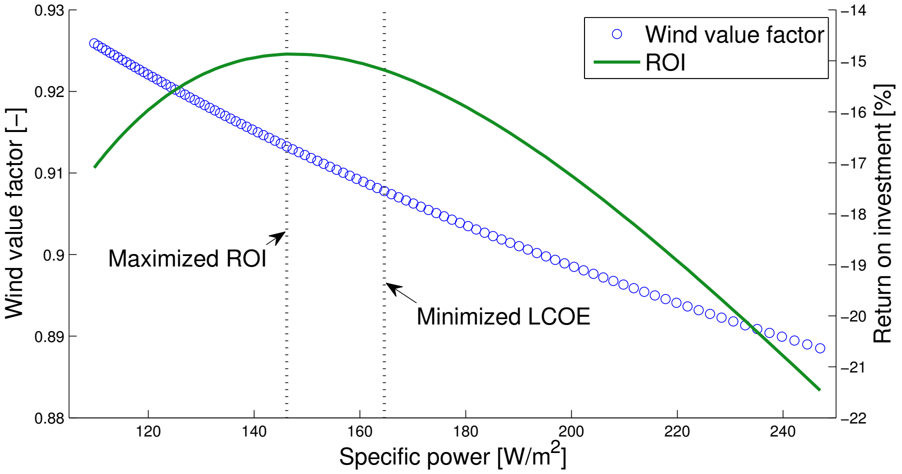

Figure 4.1: The blue rings show the specific power and the green line represents the ROI for a site with an average wind speed of 7.9 m/s, in DK1 year 2013. The dashed lines highlights the specific power for the turbine configurations which generates maximized ROI and the minimized LCOE.

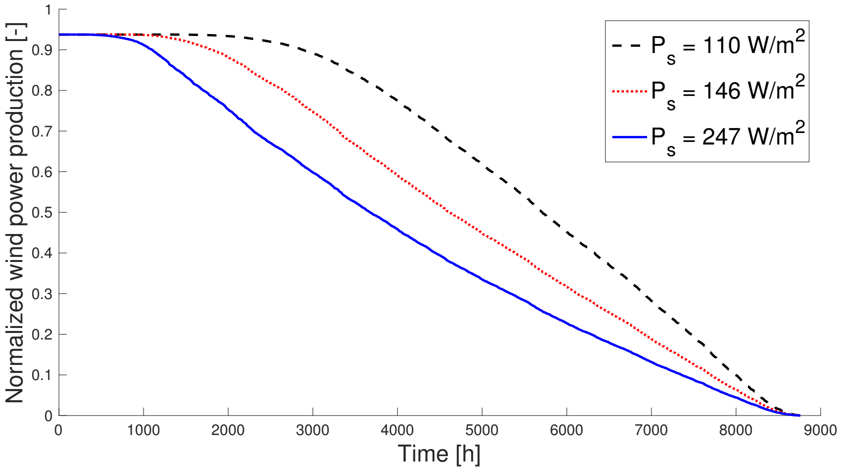

Figure 4.2: The normalized electricity production-duration curves for three different wind turbine configurations, at a site with a yearly average wind speed of 7.9 m/s.

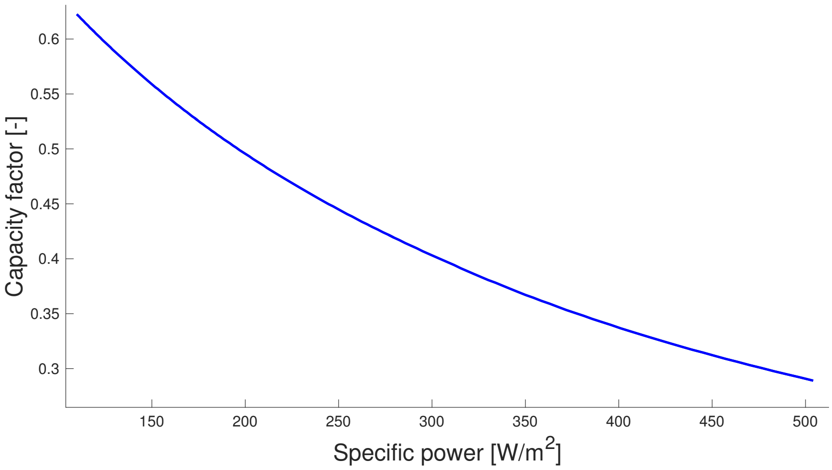

Figure 4.3: The capacity factor as a function of specific power, at a site with a yearly average wind speed of 7.9 m/s.

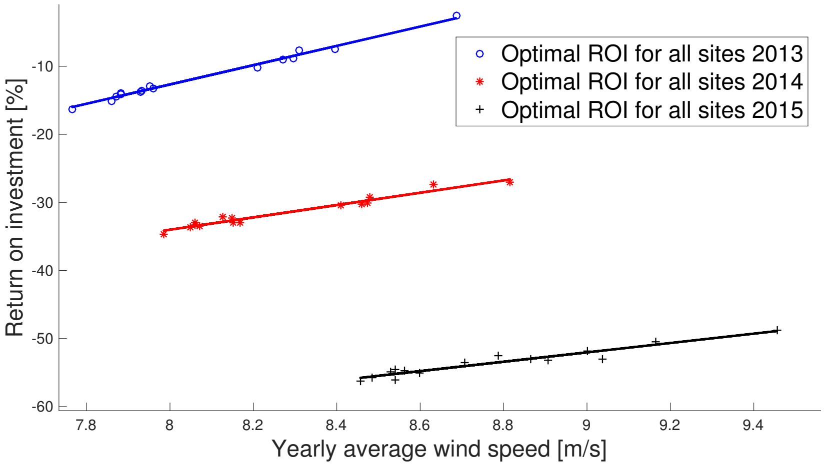

Figure 4.4: The optimal ROI in DK1 for the site specific yearly average wind speed for all sites, for the three years 2013 to 2015. Each marker represents a site within DK1. The spot price and yearly average wind speed varies between the years.

The ROI depends on the yearly average wind speed, the spot price and variations in the wind speed between sites in the same bidding area during the year. The difference in ROI between the years mostly depend on difference in spot price. The difference between the trendlines for the years 2013 and 2014 is similar to the difference between sites with lowest and highest wind speeds in year 2013. This indicates that the difference in spot price and in windiness of a site affects the profitability in similar magnitude. Different wind profiles for sites with the same yearly average wind speed seem to be of little importance for the value of produced electricity. There is no turbine at any site and year which generates a positive ROI, according to the model, this is because of low electricity prices and that no subsidies for wind power are included. A lower discount rate and a longer economic lifetime would increase the ROI, since it would lower the annual costs of investments.

In Figure 4.5, the specific power was plotted against the average wind speed for all sites in DK1, for both the minimized LCOE and maximized ROI wind turbine configuration. The optimal specific power increases with increasing average wind speed. The optimal specific power for the maximized ROI is 146 to 166 W/m^2 for sites with yearly average wind speeds between 7.8 and 8.7 m/s in year 2013. This is 15 to 20 W/m^2 lower than for the minimized LCOE.

Subsidies of wind power, where the compensation is a fixed number per produced amount of electricity for example feed-in tariffs, gives some incentives to invest in wind turbines with higher specific power than the optimal configuration without subsidies, as can be seen in Figure 4.6. Such subsidies counteracts the positive effects from investing in wind turbines with lower specific power than the wind turbines with lowest LCOE, due to the decreased dependence on the spot price for the revenue. The subsidies makes the hours of high wind speeds more valuable than the hours of low wind speeds.

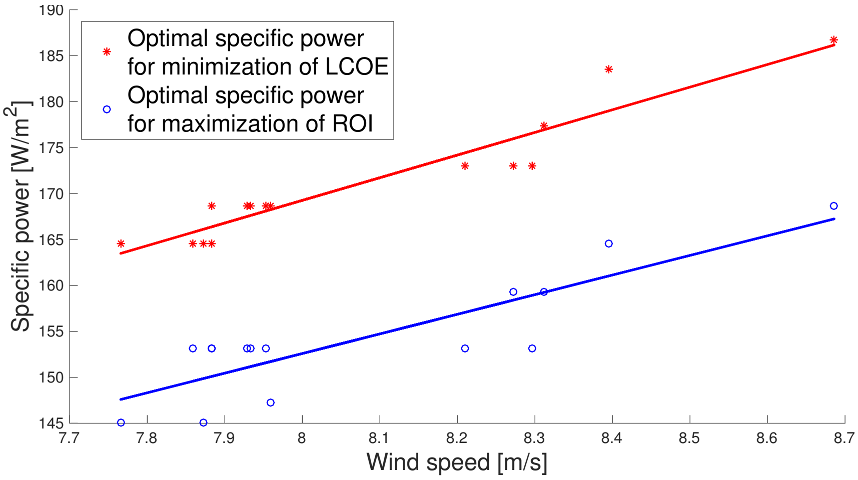

Figure 4.5: The optimal specific power for the turbines with maximized ROI and minimized LCOE as functions of the yearly average wind speed of all sites in DK1, year 2013.

The real wind turbine fleet in DK1 in the end of 2015 has an average specific power and hub height of 380 W/m^2 and 64 m, respectively. To verify the power curve model, the model was run with the total wind power capacity equally split all over DK1. The result was normalized to the real wind power production and the Pearson product-moment correlation coefficient between the modelled and real electricity production curves was 0.965, which indicates a strong correlation. In order to model the current turbine fleet with the cost model, the hub height needs to be 80 m. The wind turbine configuration with a specific power of 504 W/m^2 results in a similar electricity production pattern with an equal correlation coefficient. A sample of the real and modelled wind power can be seen in Figure 4.7.

For SE3, the cost-optimal specific power was lower than 110 W/m^2, the lower limit of the study, for most sites due to low wind speeds, therefore the comparison of different sites within the bidding area was not included for SE3 in the wind value study. The low wind speeds incentivises a lower specific power for the minimized LCOE configurations, compared to in DK1 where the wind speeds are higher. For the site with highest yearly average wind speed the wind turbine configuration with maximized ROI has a specific power of 122 W/m^2, which is 6 W/m^2 lower than for minimized LCOE, as can be seen in Figure 4.8. The maximized ROI is -30.4 % and the wind value factor increases from 0.937 to 0.954 when decreasing the specific power from 247 to 110 W/m^2, for this site in SE3 year 2013.

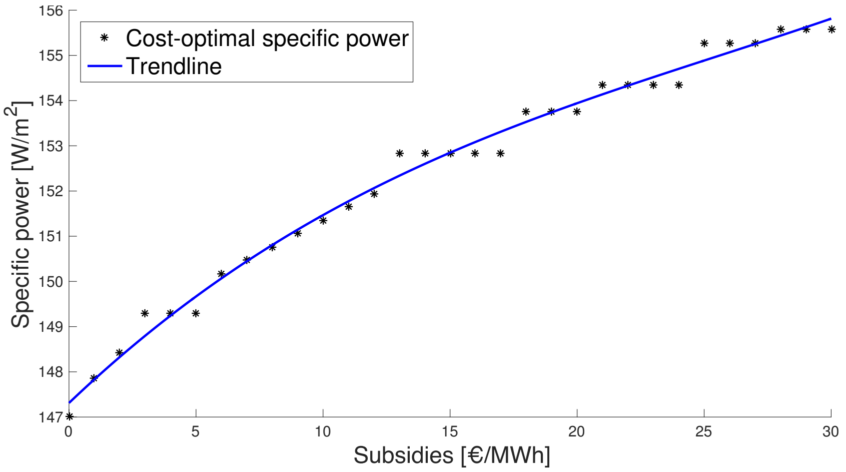

Figure 4.6: The optimal specific power for maximized ROI, with varying subsidies. At a site with a yearly average wind speed of 7.9 m/s in DK1, year 2013.

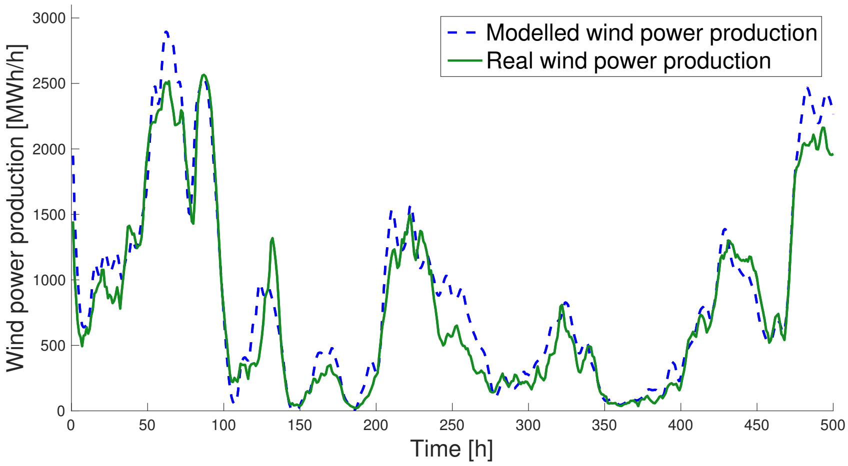

Figure 4.7: The real wind power production and the modelled wind power production with a specific power of 504 W/m^2 in DK1 for the first 500 hours of year 2013.

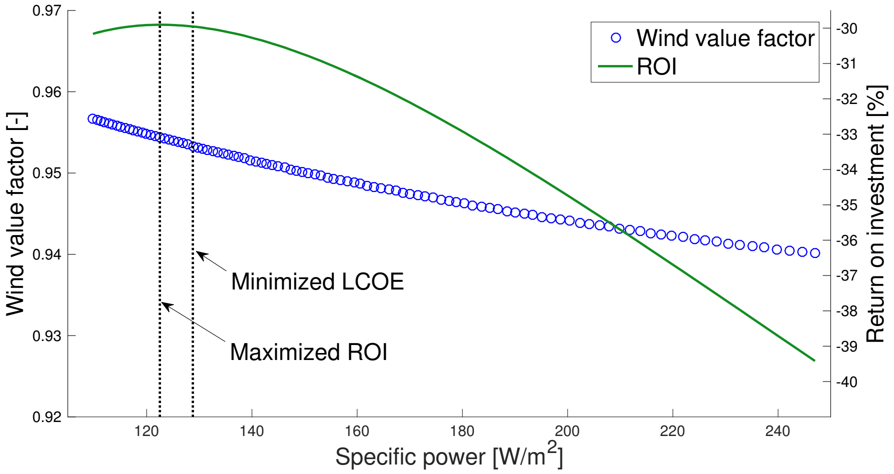

Figure 4.8: The blue rings show the specific power and the green line represents the ROI for a site with an average wind speed of 6.3 m/s, in SE3 year 2013. The dashed lines highlights the specific power for the turbine configurations which generates maximized ROI and the minimized LCOE.

4.2 The power system study

This study uses the power system model, which optimizes the investments and provides a dispatch model of the power systems in the bidding areas DK1 and SE3. The hub height, access to hydropower, access to nuclear power and a learning rate[1] for wind power was varied for the different scenarios, seen in Table 4.1. Each scenario, except the DK1 reference scenario, was modelled with six wind turbine configurations with the specific powers: 247, 204, 172, 146, 126 and 110 W/m^2. The configurations represents 1.94 MW generators with the rotor diameters: 100, 110, 120, 130, 140 and 150 m. The wind turbine configuration with a specific power of 146 W/m^2 is used when comparing the power system compositions for the different scenarios. This is an assumption of a slow development of the wind power technology towards lower specific power, compared to the wind turbine configurations of today. The DK1 reference scenario was modelled with a specific power of 504 W/m^2.

The cost-optimal Wind power penetration level increase with decreased specific power, in all scenarios for both bidding areas, which is seen in Figure 4.9 and 4.14. The difference in wind power penetration level between the configurations with lowest and highest specific power are between 11 and 26 percentage points for all scenarios. The results for the DK1 and SE3 scenarios are presented in Section 4.2.1 and Section 4.2.2, respectively. The installed capacities, electricity production mix, capacity factors, system costs, average cost of electricity and yearly average wind speed at the sites of the wind turbines, can be seen for each scenario in Appendix A.3.

4.2.1 Results for DK1

The wind power penetration levels as functions of the specific power for the three DK1 scenarios: DK1 future base, DK1 no learning and DK1 120 m hub height, can be seen in Figure 4.9. The DK1 future base scenario results in the power system with the lowest total cost. However, the difference is quite small between the three cases. There is only a few percent less wind power in the DK1 no learning scenario, despite the consequence of 15 % more expensive wind power investments. The small change implies that the power

Table 4.1: The scenarios in the power system study.

Scenario	Bidding area	Hub height [m]	Hydropower	Nuclear power	Learning rate
DK1 future base	DK1	80		×	×
DK1 no learning	DK1	80		×	
DK1 120 m hub height	DK1	120		×	×
DK1 reference	DK1	80			
SE3 future base	SE3	80		×	×
SE3 with hydro	SE3	80	×	×	×
SE3 no learning	SE3	80		×	
SE3 no nuclear	SE3	80			×
SE3 no nuclear with hydro	SE3	80	×		×
SE3 120 m hub height	SE3	120		×	×

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[1] The cost reduction for a technology over time.

system is saturated with wind power already in the DK1 no learning scenario. In the scenario DK1 120 m hub height, the lower penetration level indicates that wind speed does not increase enough with the height to make up for the more costly investments.

The total system costs are presented for different wind turbine configurations in Figure 4.10. The system costs are reduced with decreased specific power. The optimum wind turbine configuration is close to a specific power of 110 W/m^2, except for in the DK1 120 m hub height scenario where optimum is reached at a specific power of 126 W/m^2, even though it does not result in the highest wind power penetration level. In that scenario it would therefore not be cost-optimal to invest in wind turbines with lower specific power than 126 $W/m2$.

In the future base scenario with a wind turbine configuration of 146 W/m^2, DK1 gets a wind power penetration level of 79 % (102 % if including the curtailed wind power), with some additional electricity production from other power technologies for the hours with low wind speeds. More than 100 % of the regional load could be covered by wind power, if the curtailed wind power production could be stored or transmitted to other bidding areas. The installed capacity of wind power, in the future base scenario, is 3530 MW, about 10 % less than the actual installed capacity in DK1 for year 2015. The capacity factor of the wind turbines of the DK1 future base scenario is 47 % (61 % if including the curtailed wind power), which can be compared to a 32 % capacity factor in DK1, year 2015. The reasons for the increased capacity factor are lower specific power and a higher average hub height in the modelled scenarios, compared to the actual wind turbine fleet in DK1 year 2015. The wind power penetration levels for the DK1 scenarios can be seen in Figure 4.11 and a sample of the electricity production pattern for the DK1 future base scenario can be seen in Figure 4.12.

The DK1 reference scenario was simulated with a wind turbine configuration of 504 W/m^2, without cost reduction from learning since it should simulate year 2015, but with the emission limit for 2050. The wind turbine configuration was chosen, since it generates a similar power production profile as Denmark's actual wind turbine fleet, as described in Section 4.1. The validation scenario reached a wind power penetration level of 41 % (45 % if including the curtailed wind power) compared to the actual DK1 wind power penetration level of 55 %, for year 2015. The distribution of the electricity production and a sample of the dispatch can be seen in Figure 4.11 and 4.13, respectively. The low wind power penetration level in the validation case, depends on several features in the model, partly because no interregional trade is included, which reduces the flexibility of the power system. This indicates that the average wind turbine configuration in DK1 is not optimized for such a large wind power penetration level as 55 %, but it can still be functional due to the good transmission capacity to neighbouring regions.

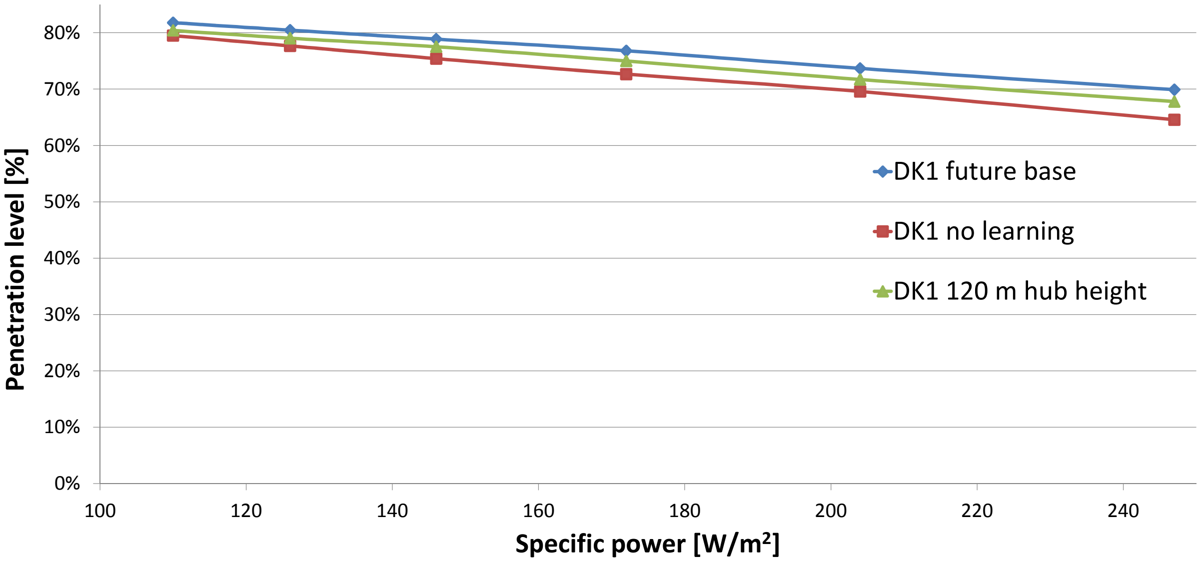

Figure 4.9: The modelled wind power penetration level for three DK1 scenarios with six different wind turbine configurations.

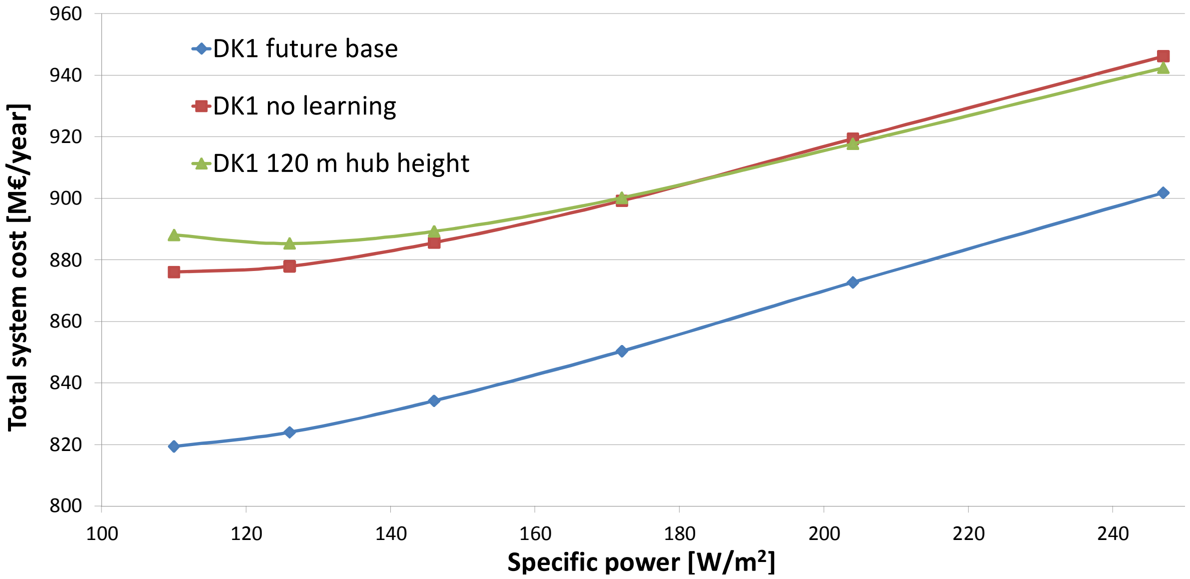

Figure 4.10: The system costs for the DK1 scenarios with six different wind turbine configurations.

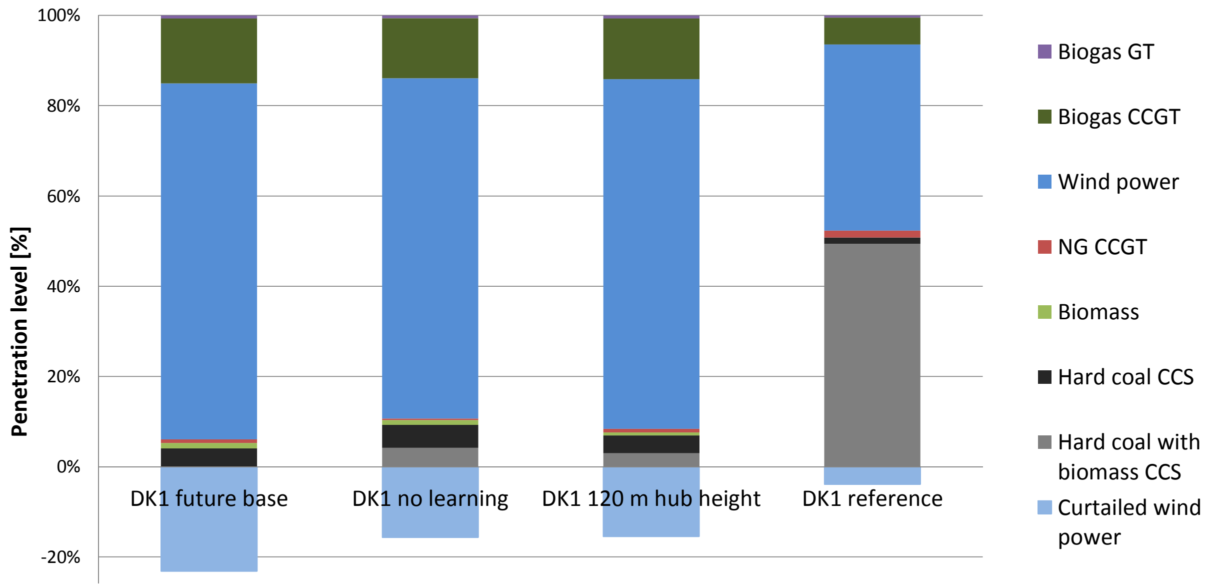

Figure 4.11: Modelled penetration levels for all technologies in the DK1 scenarios with the wind turbine configuration of 146 W/m^2 (504 W/m^2 in the DK1 reference scenario).

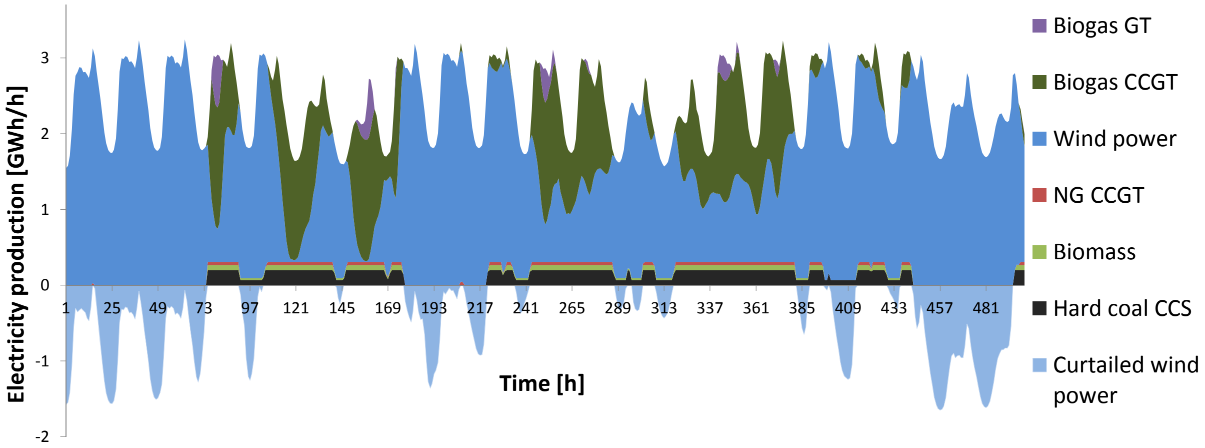

Figure 4.12: A sample of the modelled electricity production pattern for three weeks of year 2050, in the DK1 future base scenario.

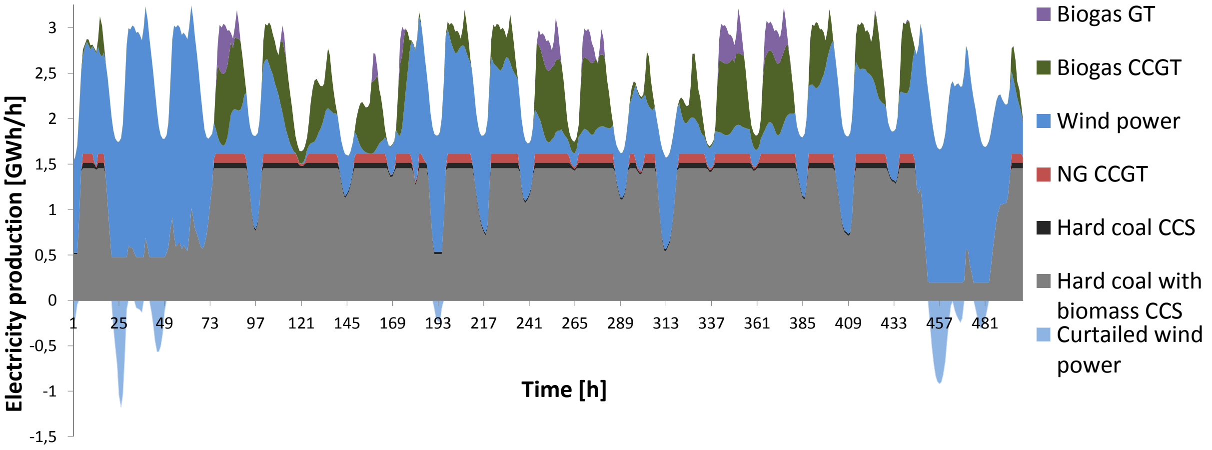

Figure 4.13: A sample of the modelled electricity production pattern for three weeks of year 2015, in the DK1 reference scenario.

4.2.2 Results for SE3

The wind power penetration levels as functions of the specific power for the six SE3 scenarios: SE3 future base, SE3 no learning, SE3 120 m hub height, SE3 with hydro, SE3 no nuclear and SE3 hydro no nuclear, can be seen in Figure 4.14. The wind power penetration levels are in all SE3 scenarios lower than for the three DK1 scenarios, seen in Figure 4.9. The penetration level of wind power doubles between the highest and lowest specific power, in the first four scenarios in SE3. The SE3 with hydro is the scenarios with lowest system cost in SE3. It reaches a wind power penetration level of 50 % for lowest specific power, which is about 30 percentage points less than the DK1 future base scenario.

The SE3 future base scenario results in wind power penetration levels between 18 and 32 % for the different wind turbine configurations. The difference in penetration level between the SE3 future base and SE3 no learning scenario is about 25 %, which shows that the SE3 power system composition is sensitive regarding the wind turbine investment costs. In SE3, wind speed increase a lot when increasing the hub height to 120 m, which results in a lower total cost and about 30 % more electricity from wind power in the SE3 120 m hub height scenario than in the SE3 future base scenario.

When adding hydropower to the model, the wind power penetration level increase even more than when increasing the hub height to 120 m. The introduction of the flexible hydropower with a high capacity factor benefits wind power, since it has the ability to act fast on the variations in the wind power production. When nuclear power is prohibited without access to hydropower, wind power almost doubled and the rest of the base load is substituted by hard coal with biomass CCS, which is assumed to be a more flexible technology compared to nuclear power. The system costs increased slightly, in the scenario SE3 without nuclear, compared to the SE3 future base scenario. The most favorable scenario for high wind power penetration level is when prohibiting nuclear power when having access to hydropower. In the SE3 hydro no nuclear scenario wind power provides more than half of the electricity demand for the three lowest specific power configurations.

The total power system costs are presented in Figure 4.15. The wind turbine configuration with a specific power of 110 W/m^2 results in the lowest power system costs for all scenarios. The system cost reductions decreases with decreasing specific power and 110 W/m^2 is close to the optimum configuration for all scenarios. The 110 W/m^2 configuration does not seem to be as close to cost-optimal configuration as in the scenarios for DK1, since the costs still declines.

In the SE3 future base scenario with the wind turbine configuration of 146 W/m^2, wind power does not provide as large share of the electricity as in the DK1 future base scenario. Wind power provides an intermediate share of 26 % of the electricity demand (28 % if including the curtailed wind power), with nuclear power as the base load. The penetration levels for the technologies in the SE3 scenarios are seen in Figure 4.16 and a sample of the electricity production pattern for the SE3 future base scenario is seen in Figure 4.17.

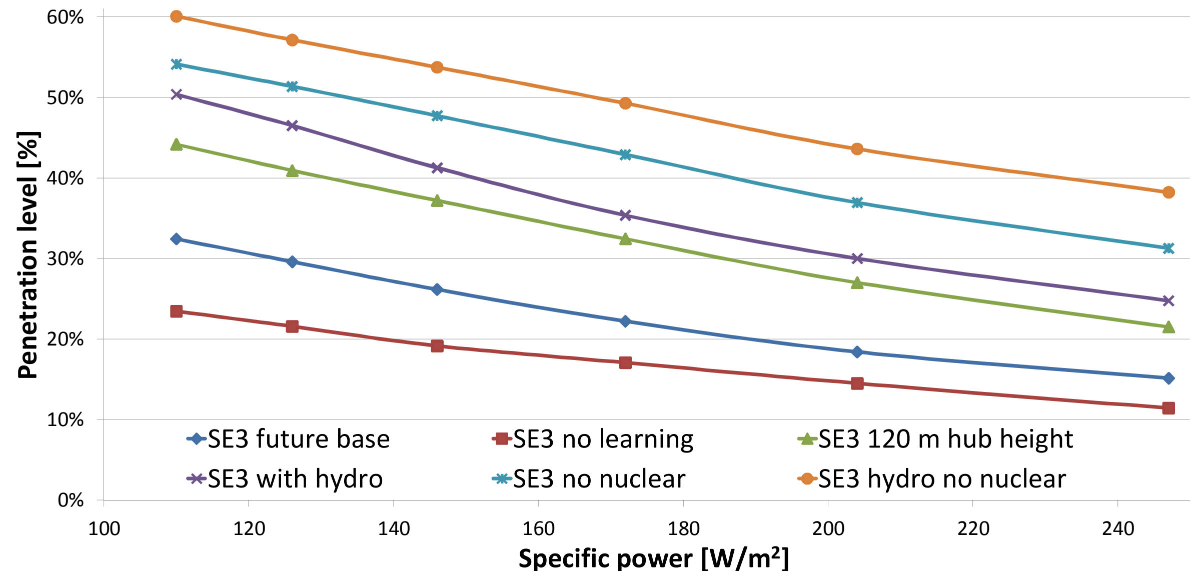

Figure 4.14: The modelled wind power penetration levels for the six SE3 scenarios with six different wind turbine configurations.

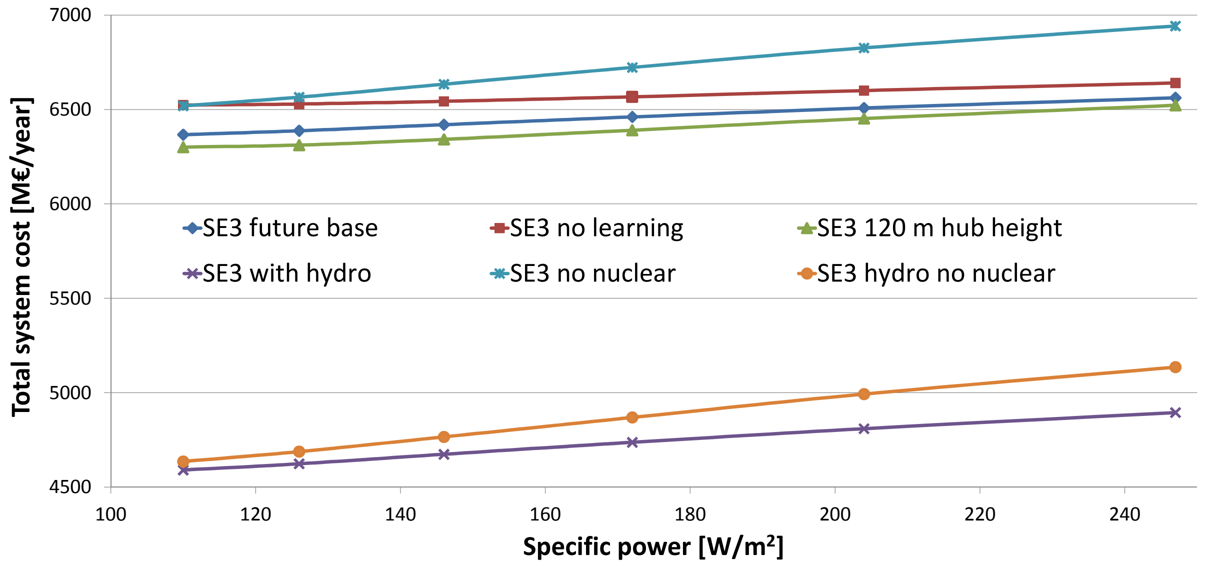

Figure 4.15: The system costs for the SE3 scenarios with six different wind turbine configurations.

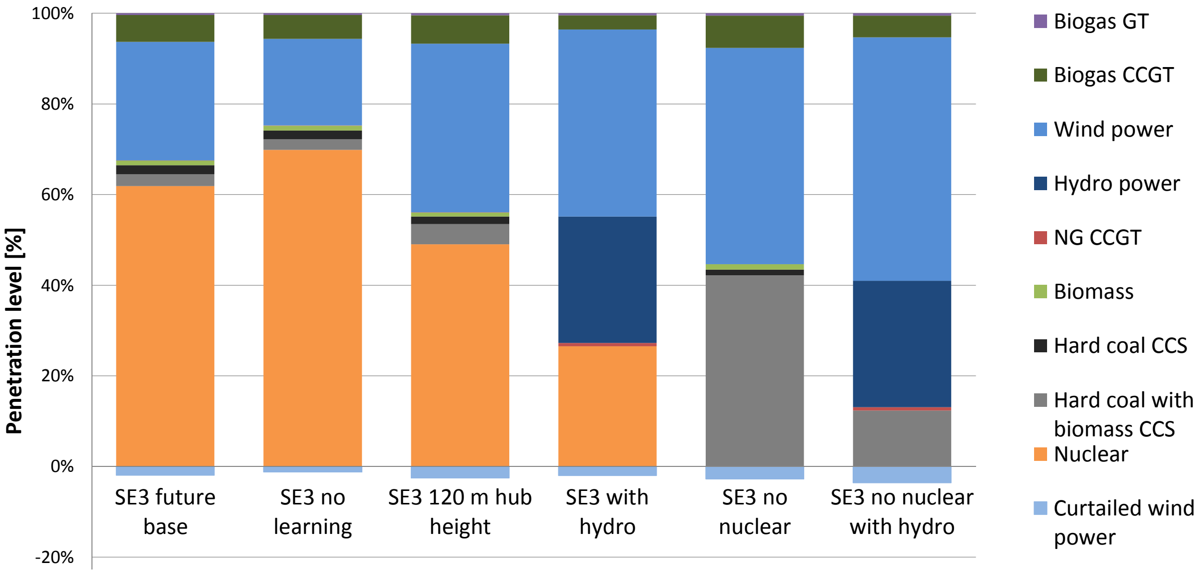

Figure 4.16: Modelled penetration levels for all technologies in the SE3 scenarios with the wind turbine configuration of 146 W/m^2.

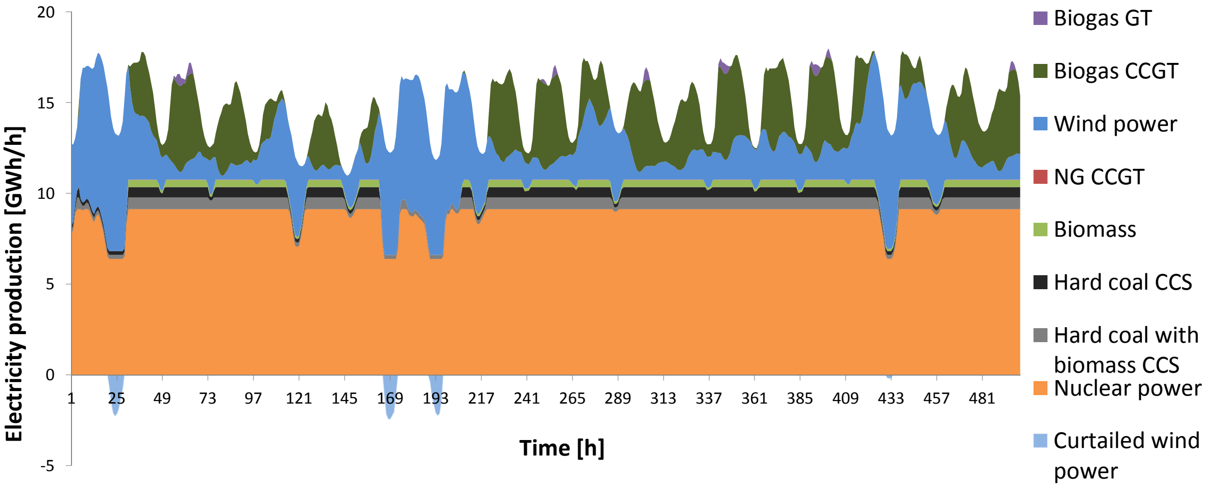

Figure 4.17: A sample of the modelled electricity production pattern for three weeks of year 2050, in the SE3 future base scenario.

5

Discussion

This study shows that ROI is maximized for a lower specific power than for the wind turbines with minimized LCOE. Both the wind turbines with maximized ROI and minimized LCOE has lower specific power than the average wind turbine installed in USA 2014 (247 W/m^2). The results also shows that wind turbines with low specific power are more cost-efficient for future power systems, than the wind turbines installed today. The optimal wind power penetration level increases with a decreasing specific power.

The difference between the wind turbine configurations with maximized ROI and minimized LCOE seems to be due to the inverse relation between the wind power production and electricity spot price, which is seen in the wind value factor. The wind value factor is higher, and has a lower dependence on the specific power, in SE3 than in DK1, which could be an effect of the lower wind power penetration level. The ROI in DK1 is higher than in SE3, which mostly depends on the difference in yearly average wind speed, and not the spot price since it is similar in the two bidding areas. The difference in ROI between DK1 and SE3 would have been larger if the wind value factor had been equal in the bidding areas.

The optimal specific power is, according to the studies, lower in SE3 than in DK1. This together with the relation between yearly average wind speed and optimal specific power in Figure 4.5 shows that the optimal wind turbine configuration is depending on the yearly average wind speed of the site. This is also indicated in the power system study, where the optimal configuration seems to be lower in SE3 than in DK1, even though in this study the 110 W/m^2 configuration is best for both regions. It would be interesting to include even lower specific power in order to find the cost-optimal wind turbine configurations for the different scenarios.

Nuclear power is a technology with a traditionally low ability to change its power output. A system with nuclear power is slow to react on sudden changes from intermittent power sources and therefore limits the cost-optimal amount of wind power in the power system. Hydropower is a very flexible electricity source and can work as a balancing power source, which can allow high wind power penetration levels.

In this study it is shown there is a difference between the optimal wind turbine configuration for one year profitability and for the cost-optimal future power system, with low carbon emissions. In DK1, the optimal wind turbine configuration for the wind value and for the power system has specific powers of 146 to 166 W/m^2 and 110 W/m^2, respectively. The future power systems benefits from lower specific power than the most profitable configurations today, due to the higher capacity factors, which leads to less investments in other electricity production technologies and less use of other fuels.

Today's feed-in tariffs, where the wind power is paid an equal amount per produced unit of electricity independent on the system requirements, slightly reduces the incentive to produce power at hours with low wind speeds. Instead the subsidies incentivises installations of wind turbines with a specific power between the cost-optimal configuration, without subsidies, and the configuration with minimized LCOE.

5.1 Assumptions and limitations

The model of the future power system contains some technologies, and fuels that are assumed to be commercial by year 2050, but that today has some uncertainties. For example CCS is not yet commercial in the power sector, and the future expansion is uncertain due to social acceptance and costs. Biogas is another example which is used in large quantities in several scenarios in this study. But in the future it is difficult assume how much biogas that could be used in the power system, since biogas might also be used by other sectors such as transportation and agriculture.

The wind power cost model originates from Moné et al. (2015), and is calculated from their given example which do not include any details of material change due to larger rotor diameters. The extrapolation of the cost is uncertain and the real prices might change substantially compared to the cost model. Another wind power cost model would result in other cost-optimal wind turbine configurations. The increase in wind power penetration levels and the cost reductions for lower specific power could then be overestimated, but a sensitivity analysis of the investment costs is included in the DK1 no learning and SE3 no learning scenarios.

The lowest specific power of 110 W/m^2, which corresponds to a rotor diameter of 150 m is not likely to be design with a hub height of 80 m. This is because the very short distance between the tip of the blade and the ground, which is 5 m. It is still included since the effect of low specific power is of interest in this study. The low specific power could also be reached by lowering of the rated power, this is however not covered by the cost model.

Different discount rates are used in the two cases, wind value study and the power system study. The difference is due to the fact that the power system study is made to show the optimal scenarios for the society, while the wind value study was made to see how actual investments are affected by the wind turbine configuration. Also the economic lifetime of 20 years is discussable, some reports use 25 or 30 years, but since the technology is under development it is difficult to know what effects the configuration choices would have. The discount rate and economic lifetime of the wind turbines has a large effect on the profitability and competitiveness of wind power, since the investment and installation costs are major to the variable costs. But discount rate and economic lifetime only have a small effect on the cost-optimal wind turbine configuration.

The C_P value have a significant effect on the power curve modelling, since the error in the cubic power function is located at the most frequent wind speeds. The modelled C_P value was made to match the real power curve for one given wind turbine with the same specific power. For the other modelled configurations, the C_P curve was modelled to match the trend for the different Enercon (2016b) turbine configurations. The information of how the C_P curve behaves with different specific power is inadequate and it is difficult to predict how the C_P curve would look like for a wind turbine with very low specific power. Therefore this model has a higher uncertainty at lower specific power and might be overestimating the power curve, for today's technology, by getting lower rated wind speed than in reality.

The comparison between the real and modelled wind power production was done to show the accuracy in time and magnitude. The real installed wind power capacity neither has the same configuration, nor is equally spread in each site, which are two simplifications of the modelled data. Despite the simplifications of the model, it shows a high correlation with the real wind power production.

The low spatial resolution of the wind data results in large areas with equal wind speeds. Even though regional wind speed variations are somewhat included, the low spatial resolution might overestimate or underestimate the real wind power potential. The variations of the wind speed profiles are however well consistent with the actual wind production as could be seen in the validation cases. Neither protected areas or other inoperable areas are regarded, since the sites are large with low resolution.

The power system study only models single regions without any transmission possibilities. This makes it more inflexible since excess electricity from wind power has to be curtailed and times with low wind power production needs to be covered by back-up power, like biogas CCGT. If several regions were modelled, import and export could reduce the need for back-up power and utilize some of the otherwise curtailed electricity from wind power. Depending on the cost of the transmission infrastructure and how well it could be utilized, modelling several regions might reduce the total system cost.

5.2 Future studies

During this work several interesting topics for further studies has appeared. Some has to do with power system modelling and wind speed data. Other side tracks are interesting for verification of the technical specifications for wind turbines with low specific power.

It would be very interesting to see what effects wind turbines with low specific power could have in larger and more complex power system models, where demand side management, regional variations in wind speed and access to other technologies is included in the model. In order to make a more realistic model it would be good to use wind speed data from micro scale, to see what results that would have on the magnitude of installed wind power in scenarios of future power systems.

Also a study of the coefficient of performance for wind turbines with low specific power, done with fluid dynamics and structural simulations, would be very interesting and needed in order to verify and improve the power curve model used in this report. The lifetime of wind turbines operating on rated power during a large share of the year needs to be analysed. This report has not included wind speed variations in lower temporal resolution than one hour, it would therefore be interesting to study the frequency control and grid compatibility of wind turbines with low specific power. A cost function, including also variability in generator capacity, hub height and rotor diameter, could provide an optimal configuration for each site.

6

Conclusion

This study models wind power in the power systems of today and in different scenarios of future power systems. The aim of this study was to analyse how the value of produced electricity from wind power change for different wind turbine configurations. The aim was also to see how the changes in the wind turbine configuration affects the wind power penetration level and the use of other technologies in scenarios of future power systems.

The results shows that wind power can play a major role in future power systems with low carbon emissions. If designing the wind turbines with lower specific power than today, large wind power penetration levels of about 60 and 80 % could be cost-optimal under strict carbon emission regulations in SE3 and DK1 respectively, without interregional transmission lines or electricity storage possibilities. The optimal wind power penetration level depends on the wind speeds and what other technologies that are allowed or available in the area.

The cost-optimal wind turbine configuration has a lower specific power in the power system study, modelling future power systems, than in the wind value study, estimating the value of different wind turbine configurations in present markets, due to large differences in the models. Investments in wind turbines with maximized profitability and minimized LCOE are not cost-optimal for the system, but still lowers the system costs for all analysed scenarios compared to the average wind turbine configuration installed in USA 2014. The study shows that a high wind power penetration steers the investments of wind power towards the future cost-optimal wind turbine configuration, according to the scenarios.

Wind power gets paid less than the average electricity production technologies, if the wind power production affects the electricity spot prices. The wind value factor does however increase with a decreasing specific power. This could be a driver for investing in wind turbines with lower specific power than the wind turbines with minimized LCOE, in power systems with high wind power penetration levels.

The studies showed that the cost-optimal wind turbine configuration is dependent on the yearly average wind speed. The electricity spot price and the wind value factor are also important parameters to include in the study before choosing wind turbine configuration for an investment.

In areas with high displacement height and high ground roughness, the hub height becomes an important factor and can have a large effect on the optimal wind power penetration level. In areas with low ground roughness, the extra costs for increasing the height can be larger than the increased value from higher wind speeds.

To conclude, wind turbine configuration has a large effect on the capacity factor and on the optimal wind power penetration. It is therefore important to include the specific power and different costs for different wind turbine configurations when modelling power systems, making policies and in investment decisions.

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Appendix A

Power system model

A description of the power system model along with input data for the different technologies and detailed results of the scenarios are presented in the appendix.

A.1 Model description

The power system model is described by a number of parameters and equations. The objective function of the power system model is to minimize the total system cost

$$c_{\text{tot}} = \sum_{i \in I} \sum_{t \in T} \left(C_{\text{run}}(i,t) \cdot p(i,t) + c_{\text{cycl}}(i,t) \right) + \sum_{i \in I} C_{\text{inv}}(i) \cdot s(i) \ , \tag{A.1}$$

where:[1]

I is the set of all power producing technologies,

T is the set of all hours during a year,

$C_{\mathbf{run}}(i,t)$ is the running cost of technology i at time t [€/MWh],

$C_{\mathbf{inv}}(i)$ is the annualised investment cost of technology i [€/kW],

$c_{\mathbf{cycl}}(i,t)$ is the cycling cost of technology i at time t [€],

$p(i,t)$ is the produced electricity by technology i at time t [MWh],

$s(i)$ is the installed capacity of technology i, [kW], and

$e(i,t)$ is the emissions for technology i at time t [kg CO_2/h].

All decision variables are required to be positive.

The power production has to balance the demand, which is ensured by the constraint

$$\sum_{i} p(i,t) \geq D(t) \qquad \forall t \in T \ , \tag{A.2}$$

---

[1] Decision variables to be determined by the optimisation are denoted with lower-case letters and the input variables are denoted with upper-case letters.

where $D(t)$ is the electricity demand at time t. The power production technologies are limited by their installed capacity through

$$p(i,t) \leq s(i) \qquad \forall t \in T,\, i \in I\,. \tag{A.3}$$

Wind power is also limited by the wind power profiles,

$$p(i,t) \leq W(i,t) \cdot s(i) \qquad \forall t \in T,\, i \in I_{\text{wind}}\,, \tag{A.4}$$

where I_{wind} is the set of wind turbine configurations and $W(i,t)$ is the availability of technology i at time t as a fraction of installed capacity.

To account for cycling costs, thermal power production technologies are limited by

$$p(i,t) \leq p_{\text{active}}(i,t) \qquad \forall t \in T,\, i \in I_{\text{th}}\,, \tag{A.5}$$

where I_{th} is the set of thermal power production technologies and $p_{\text{active}}(i,t)$ is the active capacity of technology i at time t. The cycling costs are described by

$$c_{\text{cycl}}(i,t) = c_{\text{start}}(i,t) + c_{\text{part-load}}(i,t) \qquad \forall t \in T,\, i \in I_{\text{th}}\,, \tag{A.6}$$

where $c_{\text{start}}(i,t)$ are start-up costs and $c_{\text{part-load}}(i,t)$ are part-load costs. Start-up costs are incurred when the active capacity is changed

$$c_{\text{start}}(i,t) \geq C_{\text{start}}(i) \cdot p_{\text{start}}(i,t) \qquad \forall t \in T,\, i \in I_{\text{th}}\,, \tag{A.7}$$

where $C_{\text{start}}(i)$ is the start-up cost coefficient [€/kW] for technology i and $p_{\text{start}}(i,t) \geq 0$ is the change in active capacity of technology i at time t, constrained by

$$p_{\text{start}}(i,t) \geq p_{\text{active}}(i,t) - p_{\text{active}}(i,t-1) \qquad \forall t \in T,\, i \in I_{\text{th}}\,. \tag{A.8}$$

Part-load costs are determined by the different between active capacity and electricity production through

$$c_{\text{part-load}}(i,t) \geq C_{\text{part-load}}(i) \cdot (p_{\text{active}}(i,t) - p(i,t)) \qquad \forall t \in T,\, i \in I_{\text{th}}\,, \tag{A.9}$$

where $C_{\text{part-load}}(i)$ is the part-load cost coefficient [€/kW] for technology i.

The production has to fulfil the emission regulation by

$$\sum_t \sum_i e(i,t) \leq E_{\text{tot}} \qquad \forall t \in T,\, i \in I_{\text{th}}\,, \tag{A.10}$$

where E_{tot} is the total allowed emissions for one year [kg], $\eta(i)$ is the efficiency for technology i and $e(i,t)$ is described by

$$e(i,t) \geq E(i) \cdot p(i,t)/\eta(i) + E_{\text{start}}(i) \cdot p_{\text{start}}(i,t) \qquad \forall t \in T,\, i \in I_{\text{th}}\,, \tag{A.11}$$

where $E(i)$ is the emissions [kg/MWh] for technology i and $E_{\text{start}}(i)$ is the start-up emission coefficient [kg] for technology i.

A.2 Technology parameters

Fuels and technologies included in the power system model, except wind power, and their features are presented in Table A.1 and A.2, respectively. The economical and technical features are: Fuel type, Lifetime, Investment cost, O&M var cost, O&M fix cost, Start-up time, Min load, Start-up cost, Start-up fuel, Start-up fuel type, Part load cost, η_{2015} (efficiency year 2015) and η_{2050} (expected efficiency year 2050). Hard coal CCS and hard coal with biomass CCS are technologies with carbon capture and storage, with a capture rate of 87.7 %. The carbon intensity of the fuel mix in the hard coal with biomass CCS, together with the capture rate, makes the technology carbon neutral, but not renewable. The data origins from the Ph.D. thesis by Göransson (2014).

Costs for transporting and storing carbon dioxide was set to 5.8 €/tonne and 5.4 €/tonne, respectively. The total electricity demand for year 2050 was set to 18.4 TWh for DK1 and 115.5 TWh for SE3 with the load profile from year 2011. Carbon emissions were limited to 1 % of the emissions year 1990, with the regional share based on the regional GDP. Yearly learning rate for wind power was set to 0.395 %.

Table A.1: Fuel properties.

Fuel type	Lower heating value [MJ/kg]	Carbon intensity [kg CO_2/MWh]
Biogas	21	0
Biomass	19	401*
Hard coal	25.2	342
Natural gas	46.5	207
Oil	42.8	264
Uranium	-	0

* The carbon dioxide from biomass is considered carbon neutral, but is needed for calculation of the ratio of biomass needed in order to make the hard coal with biomass CCS technology carbon neutral.

Table A.2: The features for all technologies included in the power system model, except wind power.

Technology	Fuel type	Lifetime [years]	Investment cost [€/kW]	O&M$_{var}$ cost [€/MWh]	O&M$_{fix}$ cost [€/(kW·year)]
Biogas CCGT	Biogas	30	755	0.8	50
Biogas GT	Biogas	30	378	0.7	50
Biomass	Biomass	40	1856	2.1	50
Hard coal CCS	Hard coal	40	3003	2.1	90.5
Hard coal with biomass CCS	Hard coal 89.4, Biomass 10.6 %	40	3463	2.1	107.6
Hydro (storage)	Water	500	2060	1	47
NG CCGT	Natural gas	30	780	0.8	12.96
Nuclear power	Uranium	60	5148	0	154.4

Technology	Start-up time [h]	Min load	Start-up cost [€]	Start-up fuel [MWh]	Start-up fuel type	Part load cost [€/kW]	η 2015	η 2050
Biogas CCGT	6	0.2	42.9	0.05	Biogas	0.5	0.62	0.71
Biogas GT	0	0.5	20.2	0.45	Biogas	0.5	0.37	0.42
Biomass	12	0.35	56.9	2.93	Oil	1.9	0.41	0.50
Hard coal CCS	12	0.35	56.9	2.93	Oil	1.9	0.36	0.43
Hard coal with biomass CCS	12	0.35	56.9	2.93	Oil	1.9	0.34	0.41
Hydro (storage)	0	0	0	-	-	-	-	-
NG CCGT	6	0.2	42.9	0.05	Natural gas	0.5	0.62	0.71
Nuclear power	24	0.7	400	-	-	1	0.39	0.43

A.3 Detailed results

Installed capacity, penetration level and capacity factor for the different technologies are presented for all scenarios and wind turbine configurations in this section. System cost, average cost of electricity and yearly average wind speed at the sites where the wind turbines are installed can be seen in the table notes.

Table A.3: Installed capacity, Penetration level and capacity factors for each technology in the DK1 future base scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	1.37	1.47	1.57	1.60	1.61	1.61	12.1	13.3	14.4	14.4	14.2	14.0	18.7	19.1	19.2	18.9	18.6	18.3
Biogas GT	0.95	0.99	1.02	1.04	1.06	1.07	0.5	0.6	0.6	0.7	0.7	0.7	1.2	1.3	1.3	1.4	1.4	1.5
Biomass	0.09	0.09	0.08	0.07	0.05	0.03	1.6	1.6	1.5	1.2	0.9	0.5	38.2	38.2	38.3	38.4	38.3	37.8
Hard coal CCS	0.25	0.27	0.29	0.20	0.11	0.05	5.2	5.7	6.1	4.0	2.3	1.0	44.4	44.4	44.5	43.5	42.6	42.5
Hard coal with biomass CCS	0.41	0.21	0.02	0	0	0	10.5	5.1	0.5	0	0	0	53.7	51.5	49.3	0	0	0
Hydro (storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG CCGT	0.01	0.01	0.01	0.05	0.09	0.11	0.1	<0.1	<0.1	0.8	1.5	2.0	37.1	37.4	37.7	37.3	36.9	36.8
Nuclear power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind power	3.74	3.69	3.64	3.53	3.41	3.30	69.9	73.7	76.8	78.9	80.5	81.8	39.4	42.0	44.3	47.0	49.6	52.1
(Incl. curtailment)	-	-	-	-	-	-	(89.0)	(95.1)	(100.0)	(102.1)	(103.0)	(103.5)	(50.1)	(54.2)	(57.7)	(60.8)	(63.5)	(65.9)

247 W/m^2 Total cost = 902 M€, average electricity cost = 48.9 €/MWh, average wind speed for installed capacity = 8.57 m/s.
204 W/m^2 Total cost = 873 M€, average electricity cost = 47.3 €/MWh, average wind speed for installed capacity = 8.57 m/s.
172 W/m^2 Total cost = 850 M€, average electricity cost = 46.1 €/MWh, average wind speed for installed capacity = 8.56 m/s.
146 W/m^2 Total cost = 834 M€, average electricity cost = 45.3 €/MWh, average wind speed for installed capacity = 8.55 m/s.
126 W/m^2 Total cost = 824 M€, average electricity cost = 44.7 €/MWh, average wind speed for installed capacity = 8.54 m/s.
110 W/m^2 Total cost = 819 M€, average electricity cost = 44.4 €/MWh, average wind speed for installed capacity = 8.53 m/s.

Table A.4: Installed capacity, Penetration level and capacity factors for each technology in the DK1 no learning scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	1.20	1.33	1.41	1.49	1.54	1.56	10.4	11.6	12.6	13.3	13.7	13.8	18.2	18.4	18.8	18.8	18.7	18.6
Biogas GT	0.94	0.96	0.99	1.00	1.03	1.05	0.6	0.6	0.6	0.6	0.7	0.7	1.2	1.2	1.3	1.3	1.4	1.4
Biomass	0.07	0.09	0.07	0.06	0.05	0.02	1.3	1.6	1.3	1.1	0.9	0.4	38.1	38.3	38.5	38.3	38.4	37.7
Hard coal CCS	0.20	0.21	0.24	0.24	0.20	0.18	4.4	4.5	5.0	5.1	4.3	3.9	44.7	44.5	44.5	44.6	44.7	44.8
Hard coal with biomass CCS	0.62	0.45	0.30	0.17	0.09	0.03	16.8	11.8	7.6	4.2	2.1	0.8	57.2	54.6	53.1	51.6	50.6	50.3
Hydro (storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG CCGT	0.02	0.02	0.01	0.02	0.04	0.05	0.4	0.3	0.2	0.3	0.7	0.9	36.9	37.2	37.5	37.6	37.9	38.0
Nuclear power	0.05	0	0	0	0	0	1.7	0	0	0	0	0	79.1	0	0	0	0	0
Wind power	3.22	3.18	3.18	3.15	3.11	3.07	64.6	69.6	72.7	75.4	77.7	79.5	42.3	45.2	48.0	50.4	52.5	54.5
(Incl. curtailment)	-	-	-	-	-	-	(76.6)	(83.5)	(87.4)	(91.1)	(94.0)	(96.2)	(50.1)	(54.2)	(57.8)	(60.9)	(63.6)	(65.9)

247 W/m^2 Total cost = 946 M€, average electricity cost = 51.3 €/MWh, average wind speed for installed capacity = 8.57 m/s.
204 W/m^2 Total cost = 919 M€, average electricity cost = 49.9 €/MWh, average wind speed for installed capacity = 8.58 m/s.
172 W/m^2 Total cost = 899 M€, average electricity cost = 48.8 €/MWh, average wind speed for installed capacity = 8.57 m/s.
146 W/m^2 Total cost = 886 M€, average electricity cost = 48.0 €/MWh, average wind speed for installed capacity = 8.56 m/s.
126 W/m^2 Total cost = 878 M€, average electricity cost = 47.6 €/MWh, average wind speed for installed capacity = 8.55 m/s.
110 W/m^2 Total cost = 876 M€, average electricity cost = 47.5 €/MWh, average wind speed for installed capacity = 8.54 m/s.

Table A.5: Installed capacity, Penetration level and capacity factors for each technology in the DK1 120m hub height scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	1.28	1.38	1.47	1.52	1.53	1.50	11.1	12.3	13.1	13.4	13.4	12.6	18.2	18.6	18.7	18.6	18.4	17.7
Biogas GT	0.95	0.99	1.01	1.03	1.07	1.12	0.5	0.6	0.6	0.7	0.7	0.7	1.2	1.3	1.3	1.4	1.4	1.4
Biomass	0.08	0.06	0.05	0.04	<0.01	0	1.4	1.1	0.9	0.7	0.1	0	38.3	38.5	38.3	38.2	38.0	0
Hard coal CCS	0.21	0.23	0.22	0.19	0.15	0.10	4.5	4.9	4.7	4.0	3.2	2.1	44.8	44.6	44.5	44.4	44.8	45.5
Hard coal with biomass CCS	0.53	0.36	0.21	0.12	0.10	0.11	14.3	9.1	5.3	3.0	2.5	2.6	56.5	54.1	52.2	51.3	51.5	50.8
Hydro (storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG CCGT	0.02	0.02	0.03	0.04	0.06	0.09	0.3	0.3	0.5	0.8	1.1	1.5	37.2	37.6	37.8	37.9	37.9	37.5
Nuclear power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind power	3.11	3.10	3.08	3.05	2.98	2.92	67.8	71.7	75.0	77.5	79.0	80.4	45.8	48.7	51.2	53.5	55.9	58.0
(Incl. curtailment)	-	-	-	-	-	-	(79.7)	(85.1)	(89.6)	(93.0)	(94.3)	(95.5)	(53.9)	(57.8)	(61.2)	(64.1)	(66.7)	(68.9)

247 W/m^2 Total cost = 942 M€, average electricity cost = 51.1 €/MWh, average wind speed for installed capacity = 9.11 m/s.

204 W/m^2 Total cost = 918 M€, average electricity cost = 49.8 €/MWh, average wind speed for installed capacity = 9.10 m/s.

172 W/m^2 Total cost = 900 M€, average electricity cost = 48.8 €/MWh, average wind speed for installed capacity = 9.09 m/s.

146 W/m^2 Total cost = 889 M€, average electricity cost = 48.2 €/MWh, average wind speed for installed capacity = 9.08 m/s.

126 W/m^2 Total cost = 885 M€, average electricity cost = 48.0 €/MWh, average wind speed for installed capacity = 9.07 m/s.

110 W/m^2 Total cost = 888 M€, average electricity cost = 48.2 €/MWh, average wind speed for installed capacity = 9.07 m/s.

Table A.6: Installed capacity, Penetration level and capacity factors for each technology in the SE3 future base scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	4.34	4.50	4.69	4.74	4.81	4.84	5.3	5.5	5.8	5.9	6.0	6.1	16.1	16.0	16.2	16.4	16.5	16.6
Biogas GT	2.71	2.98	3.27	3.61	3.87	4.08	0.3	0.3	0.3	0.4	0.4	0.4	1.5	1.5	1.4	1.4	1.4	1.4
Biomass	0.30	0.34	0.34	0.39	0.37	0.34	0.8	0.9	1.0	1.1	1.0	0.9	36.4	36.8	37.1	36.6	36.7	36.3
Hard coal CCS	0.54	0.52	0.54	0.58	0.52	0.48	1.8	1.7	1.8	2.0	1.8	1.6	44.8	44.0	44.0	45.0	45.0	45.1
Hard coal with biomass CCS	0.44	0.57	0.57	0.64	0.79	0.93	1.7	2.2	2.3	2.6	3.2	3.8	51.3	52.0	52.4	53.3	53.3	53.1
Hydro (storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG CCGT	0.05	0.06	0.04	0.01	0.03	0.05	0.1	0.1	0.1	<0.1	0.1	0.1	34.6	34.7	35.4	35.5	35.6	35.8
Nuclear power	10.96	10.37	9.79	9.14	8.59	8.12	74.8	70.7	66.5	61.9	57.9	54.6	90.0	89.9	89.6	89.2	88.9	88.6
Wind power	7.09	7.76	8.71	9.60	10.16	10.45	15.1	18.4	22.2	26.2	29.6	32.4	28.1	31.3	33.6	35.9	38.4	40.9
(Incl. curtailment)	-	-	-	-	-	-	(16.2)	(19.9)	(24.0)	(28.2)	(31.8)	(34.8)	(30.1)	(33.8)	(36.3)	(38.7)	(41.3)	(43.8)

247 W/m^2 Total cost = 6562 M€, average electricity cost = 56.8 €/MWh, average wind speed for installed capacity = 6.26 m/s.
204 W/m^2 Total cost = 6508 M€, average electricity cost = 56.4 €/MWh, average wind speed for installed capacity = 6.24 m/s.
172 W/m^2 Total cost = 6461 M€, average electricity cost = 56.0 €/MWh, average wind speed for installed capacity = 6.11 m/s.
146 W/m^2 Total cost = 6420 M€, average electricity cost = 55.6 €/MWh, average wind speed for installed capacity = 6.02 m/s.
126 W/m^2 Total cost = 6387 M€, average electricity cost = 55.3 €/MWh, average wind speed for installed capacity = 5.97 m/s.
110 W/m^2 Total cost = 6367 M€, average electricity cost = 55.1 €/MWh, average wind speed for installed capacity = 5.92 m/s.

Table A.7: Installed capacity, Penetration level and capacity factors for each technology in the SE3 with hydro scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	2.58	3.01	3.33	3.54	3.77	3.93	1.9	2.4	2.8	3.1	3.5	3.7	9.9	10.4	11.1	11.6	12.2	12.6
Biogas GT	2.80	3.22	3.67	4.17	4.55	4.78	0.2	0.3	0.4	0.4	0.5	0.5	1.1	1.2	1.3	1.3	1.4	1.3
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hard coal CCS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hard coal with biomass CCS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro (storage)	7.00	7.00	7.00	7.00	7.00	7.00	27.9	27.9	27.9	27.9	27.9	27.9	52.5	52.5	52.5	52.5	52.5	52.5
NG CCGT	0.47	0.48	0.47	0.47	0.47	0.45	0.6	0.7	0.7	0.8	0.8	0.8	16.6	18.5	20.3	22.1	23.2	24.0
Nuclear power	6.06	5.32	4.55	3.70	2.94	2.38	44.5	38.7	32.9	26.5	20.8	16.7	96.8	95.9	95.1	94.3	93.3	92.5
Wind power	11.16	12.15	13.28	14.64	15.51	15.76	24.8	30.0	35.4	41.3	46.5	50.4	29.2	32.5	35.1	37.2	39.5	42.1
(Incl. curtailment)	-	-	-	-	-	-	(25.5)	(31.3)	(37.1)	(43.3)	(48.8)	(52.7)	(30.1)	(33.9)	(36.8)	(39.0)	(41.4)	(44.1)

247 W/m^2 Total cost = 4895 M€, average electricity cost = 42.5 €/MWh, average wind speed for installed capacity = 6.26 m/s.

204 W/m^2 Total cost = 4809 M€, average electricity cost = 41.7 €/MWh, average wind speed for installed capacity = 6.26 m/s.

172 W/m^2 Total cost = 4737 M€, average electricity cost = 41.1 €/MWh, average wind speed for installed capacity = 6.19 m/s.

146 W/m^2 Total cost = 4674 M€, average electricity cost = 40.5 €/MWh, average wind speed for installed capacity = 6.08 m/s.

126 W/m^2 Total cost = 4623 M€, average electricity cost = 40.0 €/MWh, average wind speed for installed capacity = 6.01 m/s.

110 W/m^2 Total cost = 4591 M€, average electricity cost = 38.9 €/MWh, average wind speed for installed capacity = 5.98 m/s.

Table A.8: Installed capacity, Penetration level and capacity factors for each technology in the SE3 no learning scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	3.98	4.22	4.30	4.39	4.43	4.39	4.9	5.1	5.2	5.3	5.3	5.3	16.3	16.1	15.8	15.8	15.8	15.8
Biogas GT	2.50	2.72	2.94	3.12	3.34	3.52	0.3	0.3	0.3	0.3	0.4	0.4	1.5	1.5	1.5	1.4	1.4	1.4
Biomass	0.37	0.28	0.33	0.37	0.37	0.38	1.0	0.7	0.9	1.0	1.0	1.1	35.9	35.7	36.4	36.8	37.0	37.3
Hard coal CCS	0.60	0.60	0.54	0.57	0.60	0.58	2.1	2.1	1.8	1.9	2.0	2.0	45.2	45.0	44.6	44.6	44.6	44.5
Hard coal with biomass CCS	0.22	0.39	0.53	0.60	0.60	0.66	0.8	1.5	2.0	2.4	2.4	2.6	50.1	50.8	51.4	51.9	52.1	52.3
Hydro (storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG CCGT	0.03	0.03	0.05	0.03	0.02	0.02	0.1	0.1	0.1	0.1	<0.1	0.1	34.2	34.6	34.4	34.8	35.0	34.9
Nuclear power	11.64	11.09	10.64	10.24	9.89	9.58	79.4	75.7	72.5	69.8	67.3	65.2	90.0	89.9	89.9	89.9	89.7	89.7
Wind power	5.24	5.96	6.37	6.58	7.02	7.22	11.4	14.5	17.1	19.2	21.6	23.5	28.7	32.1	35.3	38.4	40.5	42.8
(Incl. curtailment)	-	-	-	-	-	-	(12.0)	(15.3)	(18.2)	(20.4)	(22.9)	(24.8)	(30.1)	(33.9)	(37.5)	(40.9)	(43.1)	(45.4)

247 W/m^2 Total cost = 6641 M€, average electricity cost = 57.5 €/MWh, average wind speed for installed capacity = 6.26 m/s.
204 W/m^2 Total cost = 6600 M€, average electricity cost = 57.2 €/MWh, average wind speed for installed capacity = 6.26 m/s.
172 W/m^2 Total cost = 6567 M€, average electricity cost = 56.9 €/MWh, average wind speed for installed capacity = 6.26 m/s.
146 W/m^2 Total cost = 6543 M€, average electricity cost = 56.7 €/MWh, average wind speed for installed capacity = 6.25 m/s.
126 W/m^2 Total cost = 6529 M€, average electricity cost = 56.5 €/MWh, average wind speed for installed capacity = 6.15 m/s.
110 W/m^2 Total cost = 6524 M€, average electricity cost = 56.5 €/MWh, average wind speed for installed capacity = 6.09 m/s.

Table A.9: Installed capacity, Penetration level and capacity factors for each technology in the SE3 no nuclear scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	4.95	5.24	5.40	5.46	5.59	5.65	6.0	6.5	6.9	7.1	7.4	7.5	15.8	16.4	16.9	17.3	17.5	17.6
Biogas GT	3.43	3.81	4.24	4.61	4.84	5.00	0.4	0.4	0.4	0.5	0.5	0.5	1.4	1.4	1.4	1.3	1.3	1.3
Biomass	0.36	0.37	0.37	0.45	0.49	0.54	1.0	1.0	1.0	1.2	1.4	1.5	36.6	36.0	36.5	36.8	37.3	37.3
Hard coal CCS	0.35	0.39	0.42	0.38	0.35	0.33	1.2	1.3	1.4	1.3	1.2	1.1	45.2	45.5	44.3	44.4	44.4	44.0
Hard coal with biomass CCS	10.12	9.40	8.59	7.92	7.35	6.90	60.0	53.7	47.3	42.2	38.2	35.2	78.1	75.2	72.5	70.2	68.4	67.3
Hydro (storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG CCGT	0.09	0.04	0	0	0	0	0.2	0.1	0	0	0	0	33.2	34.2	0	0	0	0
Nuclear power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind power	14.24	15.28	16.73	17.44	17.55	17.36	31.3	36.9	42.9	47.7	51.4	54.1	28.9	31.9	33.8	36.1	38.6	41.1
(Incl. curtailment)	-	-	-	-	-	-	(32.5)	(38.8)	(45.2)	(50.5)	(54.5)	(57.4)	(30.1)	(33.4)	(35.6)	(38.2)	(40.9)	(43.6)

247 W/m^2 Total cost = 6942 M€, average electricity cost = 60.1 €/MWh, average wind speed for installed capacity = 6.26 m/s.
204 W/m^2 Total cost = 6826 M€, average electricity cost = 59.1 €/MWh, average wind speed for installed capacity = 6.21 m/s.
172 W/m^2 Total cost = 6723 M€, average electricity cost = 58.1 €/MWh, average wind speed for installed capacity = 6.06 m/s.
146 W/m^2 Total cost = 6634 M€, average electricity cost = 57.5 €/MWh, average wind speed for installed capacity = 5.98 m/s.
126 W/m^2 Total cost = 6565 M€, average electricity cost = 56.9 €/MWh, average wind speed for installed capacity = 5.93 m/s.
110 W/m^2 Total cost = 6519 M€, average electricity cost = 56.5 €/MWh, average wind speed for installed capacity = 5.91 m/s.

Table A.10: Installed capacity, Penetration level and capacity factors for each technology in the SE3 hydro no nuclear scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	3.68	4.11	4.35	4.52	4.67	4.86	3.3	3.9	4.4	4.8	5.0	5.4	11.8	12.6	13.3	13.9	14.3	14.7
Biogas GT	3.65	4.02	4.42	4.78	5.00	5.19	0.4	0.4	0.5	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.3	1.3
Biomass	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hard coal CCS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hard coal with biomass CCS	4.48	3.70	3.82	2.08	1.50	0.93	29.5	23.4	17.3	12.4	8.7	5.3	86.8	83.5	80.7	78.3	76.3	75.3
Hydro (storage)	7.00	7.00	7.00	7.00	7.00	7.00	27.9	27.9	27.9	27.9	27.9	27.9	52.5	52.5	52.5	52.5	52.5	52.5
NG CCGT	0.41	0.39	0.37	0.36	0.36	0.36	0.7	0.7	0.7	0.7	0.8	0.8	21.8	24.2	25.6	26.9	27.7	28.5
Nuclear power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind power	17.53	18.13	19.24	19.63	19.53	19.29	38.2	43.6	49.3	53.8	57.1	60.1	28.7	31.7	33.8	36.1	38.6	41.0
(Incl. curtailment)	-	-	-	-	-	-	(40.0)	(46.2)	(52.4)	(57.4)	(61.0)	(64.3)	(30.1)	(33.6)	(35.9)	(38.5)	(41.2)	(43.9)

247 W/m^2 Total cost = 5135 M€, average electricity cost = 44.5 €/MWh, average wind speed for installed capacity = 6.26 m/s.

204 W/m^2 Total cost = 4993 M€, average electricity cost = 43.2 €/MWh, average wind speed for installed capacity = 6.23 m/s.

172 W/m^2 Total cost = 4869 M€, average electricity cost = 42.2 €/MWh, average wind speed for installed capacity = 6.11 m/s.

146 W/m^2 Total cost = 4766 M€, average electricity cost = 41.3 €/MWh, average wind speed for installed capacity = 6.03 m/s.

126 W/m^2 Total cost = 4688 M€, average electricity cost = 40.6 €/MWh, average wind speed for installed capacity = 5.98 m/s.

110 W/m^2 Total cost = 4636 M€, average electricity cost = 40.1 €/MWh, average wind speed for installed capacity = 5.95 m/s.

Table A.11: Installed capacity, Penetration level and capacity factors for each technology in the SE3 120 m hub height scenario. The total cost, average cost of electricity and average wind speed for each wind turbine configuration are seen in the table notes.

Technology	Installed capacity [GW]						Penetration level [%]						Capacity factor [%]					
	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2	247 W/m^2	204 W/m^2	172 W/m^2	146 W/m^2	126 W/m^2	110 W/m^2
Biogas CCGT	4.38	4.54	4.74	4.84	4.96	4.97	5.4	5.7	6.0	6.3	6.5	6.6	16.1	16.4	16.7	17.0	17.3	17.5
Biogas GT	3.22	3.61	3.95	4.25	4.52	4.79	0.4	0.4	0.4	0.5	0.5	0.5	1.4	1.4	1.4	1.4	1.4	1.4
Biomass	0.33	0.34	0.29	0.30	0.27	0.22	0.9	0.9	0.8	0.8	0.7	0.6	37.2	37.0	36.5	35.9	35.9	36.5
Hard coal CCS	0.64	0.55	0.49	0.50	0.57	0.57	2.2	1.9	1.7	1.7	1.9	1.9	44.8	44.7	45.1	44.9	44.8	44.6
Hard coal with biomass CCS	0.51	0.68	0.91	1.08	1.12	1.24	2.0	2.7	3.7	4.4	4.7	5.2	52.3	52.7	53.3	54.1	54.9	55.0
Hydro (storage)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG CCGT	0	0.03	0.05	0.03	0	0	0	0.1	0.1	0.1	0	0	0	35.3	35.7	36.1	0	0
Nuclear power	9.94	9.07	8.16	7.34	6.73	6.20	67.7	61.4	54.8	49.0	44.7	41.0	89.8	89.2	88.6	88.1	87.6	87.1
Wind power	8.15	9.34	10.37	11.04	11.38	11.59	21.5	27.0	32.4	37.2	40.9	44.2	34.8	38.1	41.2	44.4	47.4	50.2
(Incl. curtailment)	-	-	-	-	-	-	(22.8)	(28.8)	(34.7)	(39.8)	(43.8)	(47.3)	(36.8)	(40.6)	(44.1)	(47.5)	(50.8)	(53.8)

247 W/m^2 Total cost = 6522 M€, average electricity cost = 56.5 €/MWh, average wind speed for installed capacity = 7.02 m/s.
204 W/m^2 Total cost = 6452 M€, average electricity cost = 55.9 €/MWh, average wind speed for installed capacity = 6.98 m/s.
172 W/m^2 Total cost = 6390 M€, average electricity cost = 55.3 €/MWh, average wind speed for installed capacity = 6.93 m/s.
146 W/m^2 Total cost = 6342 M€, average electricity cost = 54.9 €/MWh, average wind speed for installed capacity = 6.90 m/s.
126 W/m^2 Total cost = 6312 M€, average electricity cost = 54.7 €/MWh, average wind speed for installed capacity = 6.89 m/s.
110 W/m^2 Total cost = 6301 M€, average electricity cost = 54.6 €/MWh, average wind speed for installed capacity = 6.88 m/s.

Table A.12: Installed capacity, Penetration level and capacity factors for each technology in the DK1 reference scenario. The total cost, average cost of electricity and average wind speed are seen in the table notes.

Technology	Installed capacity [GW]	Penetration level [%]	Capacity factor [%]
Biogas CCGT	0.79	6.0	15.9
Biogas GT	0.80	0.5	1.2
Biomass	0	0	0
Hard coal CCS	0.06	1.4	46.5
Hard coal with biomass CCS	1.45	49.4	71.5
Hydro (storage)	0	0	0
NG CCGT	0.10	1.6	32.9
Nuclear power	0	0	0
Wind power	2.88	41.2	30.1
(Incl. curtailment)	-	(45.1)	(33.0)

504 W/m^2 Total cost = 1082 M€, average electricity cost = 58.7 €/MWh, average wind speed for installed capacity = 8.57 m/s.

Appendix B

Power curve model

B.1 Matlab code

```
% Average configuration 2014, USA
% (2014 cost of wind energy review, NREL 2015)
hub_height = ...     % Height the hub [m]
diameter = ...       % Rotor diameter [m]
rated_power = ...    % Rated power [MW]

% disph = displacement height
% wind_speed_10m = wind speed 10 m above displacement height
% wind_speed_50m = wind speed 50 m above ground level

% Altitude extrapolation of the wind to hub_height
%(Critical analysis of methods for mathematical modelling of
% wind turbines, 2011)
alpha = log10(wind_speed_50m./wind_speed_10m)./log10(50/10);
% The calculated alpha value based on 50 m and 10 m
wind_speed_hub_height = wind_speed_50m.*((hub_height-disph)./...
                        (50-disph)).^alpha; % The extrapolated
                                            % wind speed at
                                            % hub height

steps = 1000;
v = 1:1/steps:36; % The wind vector (0 to 35 m/s)
Cp_max = 0.45;    % Coefficient of power. (Review of power
                  % curve modelling for wind turbines, 2013)
rho = 1.225;      % Density of air [kg/m3], (Review of power
                  % curve modelling for wind turbines, 2013)
                  % and (Modelling the Swedish wind power
                  % production using MERRA reanalisys data, 2015)

% Losses corresponds to 16.7 % losses
% (2014 cost of wind energy review, NREL 2015)
losses_int = 0.115; % Wake losses
losses_ext = 0.06;  % Availability and el. losses (Production DK
                    % areas 2013, NordPool (2016) and Master data
                    % register for wind turbines at the end of
                    % dec 2015, Energistyrelsen (2016))
```

```
v_rated = (rated_power*1e6./ ...
          (diameter.^2/4*pi*rho*1/2*Cp_max)).^(1/3);
% Rated wind speed calculated with the cubic power function

CP=zeros(length(diameter),length(v));

% Constructing Cp-curves
% (Overview of ENERCON platform, Enercon (2016))
for i = 1:length(diameter)
  v_cp = ceil(v_rated(i)*100)-2*steps;
  CP(i,:) = 0.15;
  CP(i,1:v_cp) = ones(1,v_cp)*Cp_max;
  CP(i,v_cp+1:v_cp+7*steps) = linspace(Cp_max,0.15,7*steps);
end

cutin = 3*steps+1;        % Cutin wind speed, Add 1 because
                          % v(1) = 0 , (Review of power
                          % curve modelling for wind
                          % turbines, 2013)
cutout = [25*steps+1 ...
          25*steps+2];    % Cutout (starting and ending
                          % wind speed) [m/s], Add 1 because
                          % v(1) = 0 , (Review of power curve
                          % modelling for wind turbines, 2013)
P = zeros(length(diameter),length(rated_power),length(v));
specific_power = rated_power'*1e6*(1./(diameter.^2/4*pi));

% Normal distribution of the regional wind power
normsteps = -3*steps:1:3*steps;
norm = normpdf(normsteps,0,1*steps);
                             % Standard deviation of 1 m/s,
                             % (Modelling the Swedish wind
                             % power production using MERRA
                             % reanalisys data, 2015)

% Creating power curves, (Critical analysis of methods for
% mathematical modelling of wind turbines, 2011)
for i = 1:length(diameter)
  for j = 1:length(rated_power)
    for k = 1:length(v)
         P(i,j,k) = ((1-losses_int)*CP(i,k)*0.5*pi*rho* ...
            diameter(i)^2/4*((k-1)/steps)^3)*1e-6;
        if P(i,j,k)>rated_power(j)
            P(i,j,k) = rated_power(j);
        end

        if k < cutin
            P(i,j,k)=0;
        elseif k>cutout(2)  % Ending cut-out
            P(i,j,k) = 0;
        elseif k>cutout(1)  % Starting cutout,
```

```
                            % stepwise going down to P = 0
            P(i,j,k) = rated_power(j)* ...
                    (1-1/(cutout(2)-cutout(1))*(k-cutout(1)));
        end

    end
  end
end

P_agg = zeros(length(diameter),length(rated_power),length(v));
% Creating regional aggregated power curves.
for i = 1:length(diameter)
  for j = 1:length(rated_power)
    for k = 1:length(v)-3*steps
      if k < 1*steps + 1
          P_agg(i,j,k) = 0;
        elseif k < 2*steps + 1
           P_agg(i,j,k) = sum(norm(2*steps+1:length(norm)) ...
           .*reshape(P(i,j,normsteps(2*steps+1:length(norm)) ...
           +k),[4*steps+1 1])')*(1-losses_ext);
        elseif k < 3*steps + 1
           P_agg(i,j,k) = sum(norm(steps+1:length(norm)).* ...
           reshape(P(i,j,normsteps(steps+1:length(norm))+k) ...
           ,[5*steps+1 1])')*(1-losses_ext);
        else
           P_agg(i,j,k) = sum(norm.*reshape(P(i,j,normsteps ...
           +k),[6*steps+1 1])')*(1-losses_ext);
      end
    end
  end
end
```