Increase in wind power towards 2020

An analysis of how the increase in wind power will affect the hydro power market

Cecilie Margrethe Jonassen

Norwegian University of Life Sciences
Department of economics and resource management
Master Thesis 30 credits 2012

Preface

This thesis has been written to complete a five year master's programme in Industrial Economics at the University of Life Science in Ås. The combination of engineering and economic studies have been of great interest, and provided a broader knowledge of the energy market.

I would like to use this opportunity to thank my supervisor, Olvar Bergland, for his engagement in the research and for always helping when needed. A special thanks to June for your proofreading. I would also like to thank my incredible mom who has been my biggest supporter through my studies. And at last to my future husband, Jon Petter, thank you for being you!

Summary

This research study focuses on the potential increase in wind power caused by incentives made to increase the share of renewable production. There are estimated sensible supply and demand curves based upon the two stage least square regression analysis with the use of instruments. The data used are collected mainly from Nord Pool Spot and Norwegian Water Resources and Energy Directorate. The regression analysis has been done using STATA.

The analysis is based upon two different markets, one hydropower market (NO1) and one combined market consisting of thermal and wind power (DK1). There are made 24 supply and demand curves for each market, one for every hour of the delivery day. There have been done simulations in Matlab with increase in wind power in DK1. The results show that when only increasing the wind power generation the prices will decrease. When expanding the transmission capacity the price effect becomes ambiguous. The increase in wind power will for high inflow periods increase the overflow in the hydro power market.

Table of Contents

1 Background

The standard of living in the Nordic countries is highly dependent on electricity. Due to the increase in climatic changes and high carbon emissions, the European Union implemented the Renewables Directive. The directive enfolds the goals to reduce greenhouse gases with 20 percent compared to the year 1990 and to increase the share of renewables to 20 percent[2]. In addition it attempts to reduce the primary electricity consumption by the year 2020 [2]. In the light of the Renewable Directive, Norway and Sweden signed for a mutual arrangement to start with el-certificates. The 1st of January 2012 this was implemented in Norway[3]. The purpose of the certificates is to give an economic compensation to make production based on renewable energy more profitable. The goal by the end of 2020 is to increase the renewable production with a total of 26.4 TWh in Sweden and Norway combined [3].

All the new Directives combined with the need for environmental friendly ways of production from new sources such as wind power, are developing at high speed. Wind power is a generation of power that is highly stochastic and quite difficult to forecast. Since there is no way of storing the potential energy from the wind, like we store the potential energy in hydro power reservoirs, the wind power is more difficult to handle. Due to this, the wind power will affect the power market in a different way than the regulated power does.

From the report written by “The European Wind Energy Association” [4] it is clear to see that wind power is an energy form that has been increasing extensively during the latter years. In 1995 the total installed capacity in the European Union was 2.5 GW, and by the end of the year 2011 the installed capacity had increased to approximately 94 GW [4].

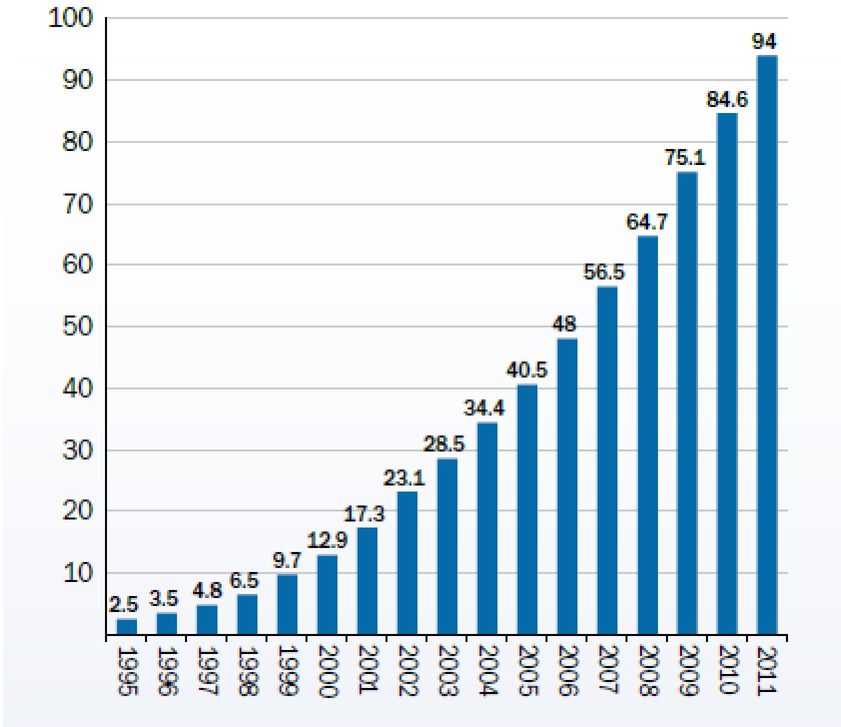

Figure 1: The graph shows the total installed capacity (GW) in the EU from 1995 to 2011[4]

Because of the increase in unregulated power and the inertia of the thermal system a thought and a discussion of Norway acting as a green battery is becoming of greater interest in Europe. Since Norway is a nation where most of the electricity production is produced using hydropower and a large share of this is storage power. The possibility of combining the intermittent wind power with pumped hydro power is an interesting thought. This would mean that when there is high wind Norway could import the cheap wind power and pump the water back up into the reservoirs. When the wind stops blowing, and there becomes a lack of supply, Norway would then start producing the hydro power and sell power back at a higher price. But the possibility of this is a different discussion, and will not be discussed further here. But on the path towards an integration of the wind power, it is of great interest to actually see how the market is affected by the increase in wind power.

The markets considered in this thesis are divided into two. One market with production generated mainly from hydro power and one market which consist of thermal and wind power. The countries taken into account in this thesis are Norway (NO1), which is the hydro power market, and Denmark (DK1), which is the thermal and wind power market. The simulations are done on the historical data from the years 2004 until 2011.

1.1 Research question

It is on the basis of all the new incentives and the trend in increasing wind power where my interest in this matter started. The questions focused in this thesis are:

- How will the increase in wind power affect the prices in Norway and Denmark?
- How will this increase in wind power affect the hydro power market?
- What would be the case if there are no bottlenecks in the transmission capacity?

2 Microeconomic theory

Chapter 2.1 and 2.2 will cover the basic supply and demand theory and optimizing of social welfare. While chapter 2.3will cover the price elasticity.

2.1 Demand and supply

The amount of quantity supplied, and the price calculated in the market are dependent on both the consumers demand as well as the supply from the producers. The demand curve is formed by the consumers willingness to buy different quantities at different prices. The producers are willing to produce/sell different quantities at different prices, depending on their marginal cost from production, which forms the supply curve. This is illustrated graphical in figure (2) with the quantity at the horizontal axis, and price at the vertical axis.

2.2 Social welfare and equilibrium

To understand the meaning of the social welfare (social surplus) the consumer- and producer surplus is introduced and illustrated in figure 2. The market price is the price that the consumers pay and the producers receive for the given quantity Qx. The consumer surplus (CS) is a measurement of how much the consumers welfare increases when the consumer is increasing his or hers consumption. The difference between the consumers willingness to pay, and the actual price the consumer has to pay for the quantity, is the consumer surplus. The producer surplus (PS) is the difference between the price the producer receives, and the price that he is willing to sell for.

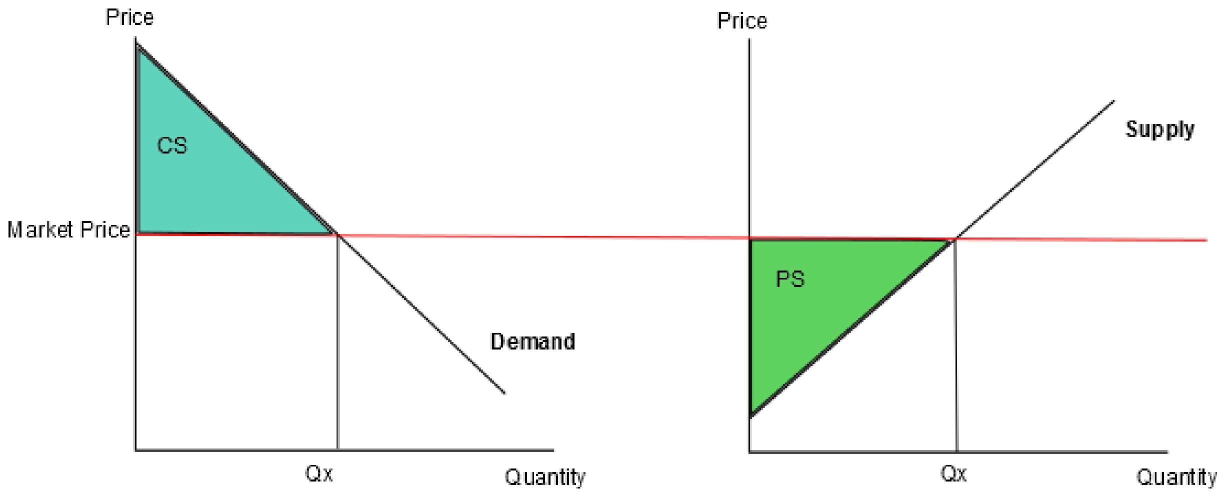

Figure 2: A simple demand/supply curve dependent on quantity and price. At a quantity Qx the consumer is willing to pay Px.

Combined the producer- and consumer surplus equals the social surplus (social welfare). The intersection of supply and demand, illustrated in figure 4, is called the equilibrium. In the equilibrium solution, the social welfare is maximized and the social optimal price (P_s) and quantity (Q_s) is found.

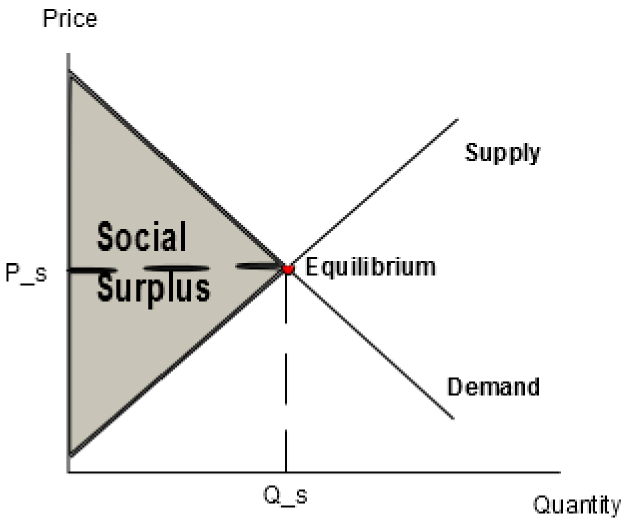

Figure 3: Social surplus and the equilibrium solution. The intersection between the supply and demand curves is called the equilibrium price and quantity, and the maximisation of the social welfare is found here.

The Norwegian energy law § 1-2 [5] states, that it is there to ensure that all parts of the energy chain is carried out in a social efficient manner. This includes the production process, transformation, transmission, turnover, distribution, and the consumption of energy. All private and public interests that are affected shall be taken into account. To obey to this law the market price (system price) will be set in the social optimal solution as done by the Nord Pool Spot. Setting of the system price will be explained more thoroughly in chapter 4.

2.3 Price elasticity

Electricity is defined as a necessary good. This implies that the change in price of electricity is not going to affect the quantity demanded to the same extent as luxury goods. The price elasticity is defined as:

$$E_p = \frac{Percentage\ change\ i\ quantity}{percentage\ change\ in\ price}$$

If the Ep < 1 we have inelastic demand, which would be the case for the demanded quantity of electricity. In an extreme case where an increase in price did not affect the quantity demanded at all it would mean that we have a perfectly inelastic demand and a vertical demand curve. In the short run it there would be difficult to react upon the price changes since for many purposes there is a lack of good short run subsidies for electricity. In Norway, where the electricity is used a lot as thermal power, the possibility to decrease electricity consumption and instead use subsidies such as wooden oven or oil boiler would make the consumers more price sensitive. While the Danish consumers, which are not using electricity to the same extent for heating purposes, would possible be more independent of the price than the Norwegian consumers.

3 Power in different markets

Chapter 3 is meant for a brief understanding of the different markets, their technologies and their marginal costs.

3.1 Norway - Hydro power market

The main production in Norway comes from hydro power, and a large share of these plants has storage capacity. From the period May 2011 to April 2012, the electricity generation in Norway was 142.6 TWh [6]. From table 1 it is shown clearly that the main generation came from hydro power. Even though some new installations of renewable power have been installed during the later years, the hydro power is still dominating the electricity generation in the Norwegian market.

Table 1: The table shows the electricity production in Norway from May 2011 to April 2012 divided into type of production. (data gathered from SSB [6]).

Resource	Power generation (GWh)	Percentage
Hydro power	137 594	96,52%
Thermal power	3 598	2,52%
Wind power	1 367	0,96%

The hydro plant takes the advantage of using the potential energy in water stored at high levels. When the water falls through a shaft to a lower level, it hits a turbine that starts rotating. The turbine is connected to a generator that generates electricity, and the electricity is then distributed to the transmission grid. Compared to power generation that uses inputs such as coal and oil, the hydropower generation has very low marginal costs. Since water is a free resource, and other marginal costs such as maintenance costs and costs associated with start-/stop are small, it is often argued[7] that the marginal cost is equal to zero. Instead the hydropower producers operate with a water value. The water value represents the opportunity cost of using the water today, instead of using the water tomorrow. This means that the water value represent the value of the water stored in the reservoirs. In chapter 6 the effect the amount of water stored in the reservoirs dos have on the price is clearly illustrated.

3.2 Denmark – Thermal- and wind power

Electricity from wind power is made when the turbine blades rotates due to the wind. The mechanical energy is then transferred from the turbine through the drive shaft, and is then converted to electrical energy in a generator before it is distributed to the transmission grid. The effect (P) made from a wind power park is calculated as follows[8]:

$$P = \frac{1}{2}\pi r^2 \rho v^3$$

Where ρ is the symbol for the density of air, πr^2 is the area covered by the turbine blades and v is the symbol for wind speed. This formula illustrates the importants of the wind speed affecting the potential production, where wind speed is of third grade. Still it is important to remember the turbines are not able to use all of the incoming wind. The wind speed needs to be at least 4-5m/s for the blades to rotate. Here there is also a week point; when the wind speed exceeds 25 m/s the common wind turbines are shut down to avoid "wear and tear" on the turbines[8]. The marginal costs of producing wind are even lower than the ones from hydro power. After the turbine being installed there are few to none costs associated with the generation. Still there will always be some costs running any power plant, and this will be illustrated in the figure 4.

Thermal power is produced burning sources such as oil, gas or coal in a boiler. The steam produced from the combustion goes through a turbine where the steam expands and thereby doing work on the turbine. The turbine is connected to a generator which generates electricity sent out on the transmission grid. The marginal costs associated with thermal power are high compared to the wind- and hydropower plants. The high costs are because of the price on the inputs such as coal, oil and gas. There are also high starts and stop costs due to the inertia in thermal production. The inertia will cause the suppliers of thermal power plants difficulties in regulating up and down, at short notice, making thermal power difficult to coordinate with the intermittent wind power. The marginal cost (supply curve) given in a combined market is shown by figure 4.

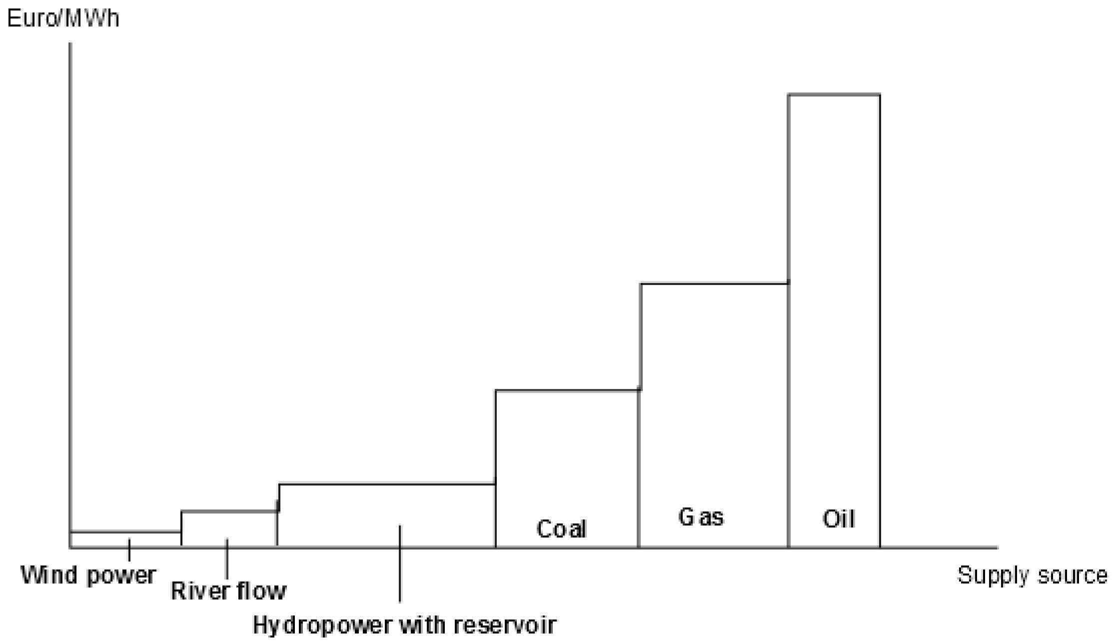

Figure 4: Merit Order. The figure illustrates the marginal cost of producing power for the different power plants. The thermal power plants have the highest marginal cost while wind power and river flow have the least marginal costs.

The figure 4 is illustrates the aggregated supply curve (marginal cost) in a market with different types of power production. The figure is often referred to as the merit order, and it is starting with the energy production that has the lowest marginal cost.

4 Price theory

This chapter will cover the basic knowledge of how the price and produced quantity is found in a combined market. The theory in this chapter is based upon the chapter 5 in Finn Førsunds book “Hydropower economics”[7].

The aggregated supply curve is shown as a merit order in figure 5. Where the demand curve intersects with the supply curve, we find the equilibrium price, P. This price is given to all producers, which in turn means that the producers with the lowest marginal cost will get the highest producer surplus, while the gas plant producers will get their price equal to their marginal cost.

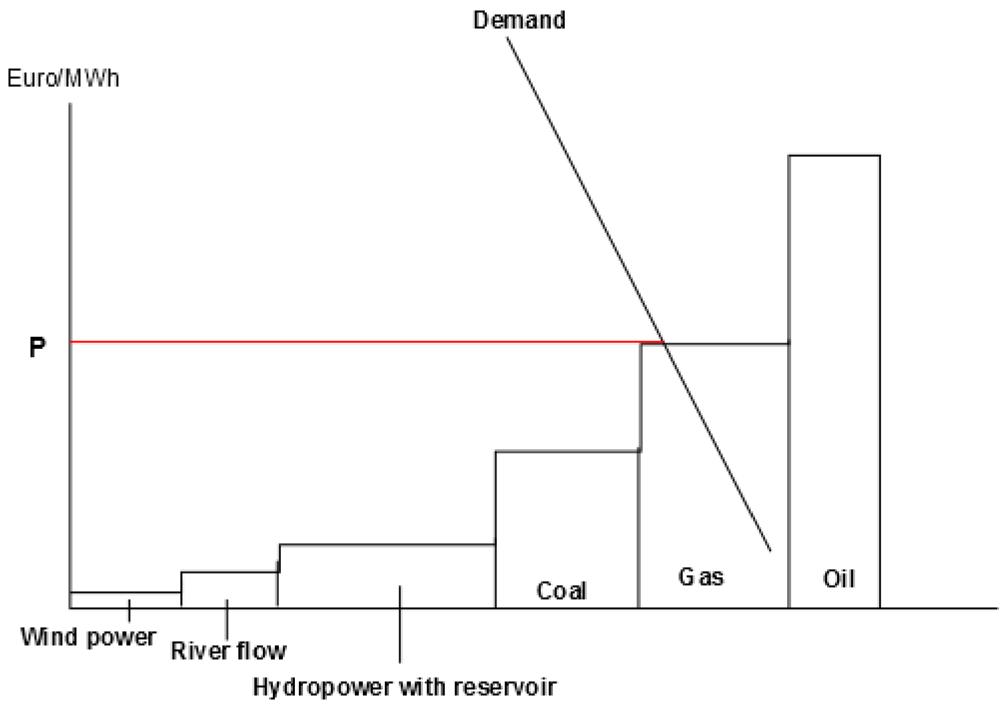

Figure 5: The figure illustrates the price set in a mixed market with a certain supply and demand.

As discussed in chapter 2 the wind production will increase in the coming years. If all other production is kept equal to the scenario in figure 5 the amount of wind power sold to a lower marginal cost will shift the other production sources to the right as shown in figure 6. The demand curve which in figure 5 was intersecting with the supply at a price P_0 is now reduced to price P_1 in figure 6. The increase in wind generation will then cause some of the coal plants and all of the gas plants to stop producing until the price rise above their marginal cost.

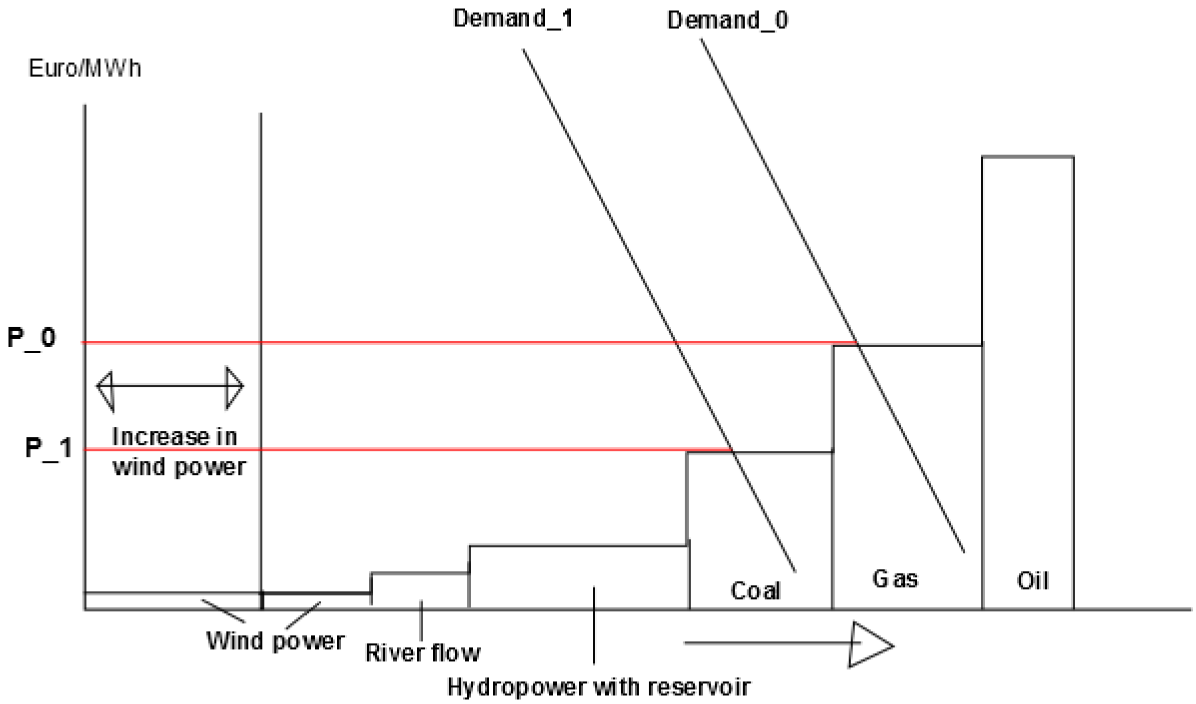

Figure 6: The figure illustrates the shift in price from P_0 to P_1 when there are increased wind power generation.

4.1 Nord Pool Spot

"Nord Pool Spot" runs the leading power market in Europe. The market called Elspot, is a market trading electricity with physical delivery for the next day. The prices are set, based upon the transfer capacities, given by the transmission operators, the offered supply, and the asked demand from members trading in the market. All the supply and demand from all members are aggregated into one supply and one demand curve, as illustrated in figure 7. The supply curve is based upon the merit order, and the demand is based upon the willingness to buy as explained in chapter 2. There is made one aggregated supply and demand curve for each of the 24 delivery hours. The system price is set in the intersection between the aggregated supply, and the aggregated demand curve, which is where we find the social optimal solution described in chapter 2. Area prices are also calculated for each of the next days delivery hours. The area prices are further explained in chapter 4.3. [9]

Figure 7: The system price is found where the aggregated demand and supply curve intersects. (Nord Pool Spot [9])

4.2 Elspot areas

The Norwegian power market is divided into different bidding areas or so called Elspot areas. The regulation law "system operation in the power system" §5 states that Elspot areas are made to deal with bottlenecks in the regional and national grid[10]. Today, Norway is divided into five Elspot areas. These five areas were not implemented before 15th of March 2010[1]. The estimations done in chapter 5 are using data from the old bidding area NO1, which was the case before 11th of January 2010[1]. The figure 8 and 9 illustrates the new and old Elspot areas. As seen from this; NO1, NO2 and NO5 are actually the old NO1. The Danish market is divided into two Elspot areas, DK1 and DK2.

Figure 8: Elspot areas. The old Elspot areas showing NO1 used in the estimations and anlysis in this thesis. [1]

Figure 9: Elspot areas. The new areas rom 15th of March 2010, and is still the current Elspot areas (2012). [1]

4.3 System price and area prices

The system price given by Nord Pool Spot is the price in the equilibrium solution assuming that there is none bottlenecks in our transmission grid. This means that when setting the price there is assumed to be unlimited available transfer capacity from one Elspot area to another. An opposite case is when we are not able to transfer all the capacity from one Elspot area to another, and we get area prices. In reality this often is the case. One example is the weak transmission grid in Norway which has divided Norway into five different Elspot areas. Figure 10, provided by Statnett, which shows the capacity transferred from the different Elspot areas and the exchange volume transferred between countries. The price in Elspot area NO1 is for the 8th of august 2012 during the hours between 11 and 12'o clock set to 12.65 euro per MWh. The price in NO2 in the same hour is 15.94 euro per MWh. Price areas are not necessary the same as the Elspot areas. A price area is defined as an area where the price is equal[11]. In many cases a price area consists of more than one Elspot area. From the figure 10 there are equal price in four of the five Elspot areas, this means that NO1, NO5, NO3 and NO4 makes one price area and NO2 is a different price area.

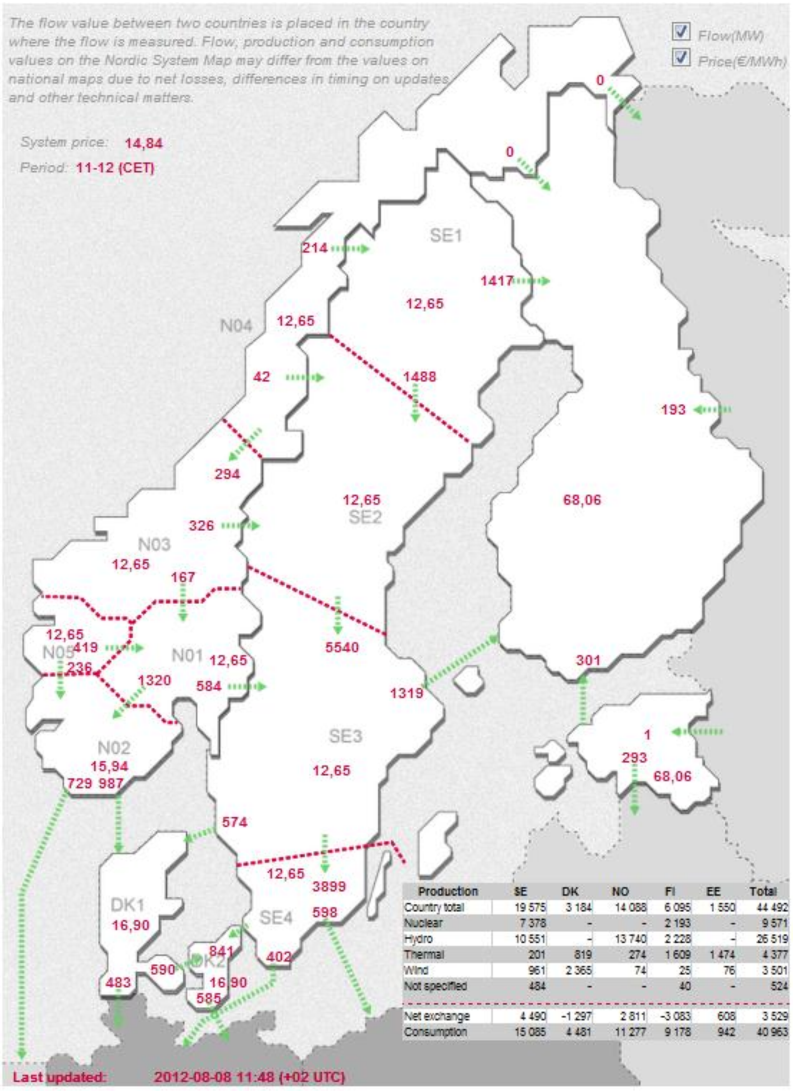

Figure 10: The figure illustrates the Nordic power flow and area prices at the 8th of August 2012 in the hour 11 to 12o'clock. [12]

The green arrows in the figure illustrate the way the power is transferred. Power flows from an area with low prices towards a high price area.

When there is a high supply of wind power, the power needed to be transferred may then be higher than the possible transmission capacity between Norway and Denmark. The price in Denmark will then most likely decrease at a higher rate than the price in Norway. This will then cause price areas. This price effect from high wind power is one of the things simulated later on in chapter 9 and 10.

5 The estimation of the market model

Before the modeling of the actual price effect from increased wind power is shown, good supply- and demand curves need to be estimated for the Norwegian (NO1) and Danish (DK1) market. With the use of the software program Stata the estimated equations for supply and demand have been estimated and tested for significance of the variables and instruments. This is done based on the method used for calculation of the system price and area prices set at Nord Pool Spot in the day ahead market. The market model is based upon one supply and one demand curve for each hour during the day and in each market. This makes a total of 96 estimated curves. All the results from the estimation and the test are found in the electronic attachment. The code written for the estimation (a so called do-file) is found in appendix 2. The data set, do-file made for the estimations and all the results from estimation are also attached as an electronic appendix.

5.1 Data/Sources

The data set[1]named nphour.dta is used for the estimations and simulations, and is found as an electronic attachment to this thesis.

The temperature and day length data for Norway and Denmark are collected from "Weather underground"[13]. The data for the reservoir filling and inflow is collected from Norwegian Water Resources and Energy Directorate (NVE)[14]. The oil prices from U.S. are from Energy Information Administration (EIA)[15]. Both the oil prices and carbon prices are converted from dollar to euro. For the exchange rate the European Central Bank have been used[16].

The rest of the data are mainly gathered from a server at Nord Pool Spot[17] containing historical data from production, system and area prices, exchange volumes, CO_2 allowances and several other variables. The variables are shown for each hour during the day (hour 1 to hour 24) and the estimation and simulation are based on the year 2008 to the end of 2011. The estimation for the supply and demand in the two markets, NO1 and DK1, is based upon the data from 12th of April 2004 until 13th of April 2008 (found as an index idz in the data set). The estimation is done before the exchange cable between Norway and Netherlands were

[1] The Data set are acquired by Olvar Bergland, UMB

introduced in the power market and narrowed down because of some lack of data for temperatures in the time period prior to April 2004.

Since we are using a double log on the variables later on, wind generation and the prices in NO1 and DK1 which are equal to zero is set to 0.1 before taking the log. The heating degree values, that are less than one, will give negative values when implementing the log. Therefore, the log of heating degrees which are lower than 1, is set to zero.

Norwegian summer holidays are often centralized during the three last weeks in July. In the data set nphour.dta the weeks 28, 29 and 30 are in each year defined to be the summer holiday dummy for Norway called “dsumm”. For the Danish market, the summer holiday is more spread out and covers the months June, July and August. The dummy dksumm is therefore defined to cover the weeks 27 to 34.

Most of the data is given as hourly data, while some of the data is daily or weekly data. System and area prices, import/export, production/generation and temperature data is hourly. The variables Oil price, carbon price, day length, industrial production index, trend, sinus and cosinus are day based data. The reservoirs levels, collected from NVE, are week based data.

An overview of the main variables used in the estimation is presented in table 2.

Table 2: A overview of the variables.

Variable name	Description
year	Year
week	Week
day	Day
hour	Hour
lnprice_no1	Log of price in NO1
lnprice_dk1	Log of price in DK1
no1_inflow	NO1 inflow (GWh)
no1_normcont	NO1 normal res (smooth)
lnrel_reservoir_no1	Log of relative reservoir filling
gen_dk1_wind	Generation of wind
lngen_dk1_thermal	Log of total thermal generation in DK1
idz	Sample index (NO1 pre NorNed)
tsin	Trigonometric cycle (sine)
tcos	Trigonometric cycle (cosine)
dsumm	Dummy for summer vacation in NO1
dksumm	Dummy for summer vacation time in DK1
dwkday	Dummy for workingdays
lndlength	log of daylength in Oslo
dlight	Dummy for daylight in on Oslo
lnipi	Log of Industrial Production Index
lnpoil	Log of oil price
lnpcoal	Log of coal price
lnco2_p	Log of CO2 spot price
co2_d	Dummy for CO2 market
lnheatdeg_osl	Log of heatingdegree in Oslo
lnheatdeg_osl_2	lnheatdeg_osl squared
lnheatdeg_cph	Log of heating degree in CPH
lnheatdeg_cph_2	lnheatdeg_cph squared
tempx_osl	temperature in Oslo
tempx_cph	temperature in Copenhagen

5.2 Supply and demand

The supply and demand model is based upon microeconomic theory. The supply and demand is estimated on a linear logarithmic form (or a so called “double log”). This is done for the purpose of using the coefficients estimated to be able to see the elasticity of the curves and how each variable is influencing this. The data is time series data. There are three endogenous variables determined in the model. Which is the price for electrical power, the quantity supplied and the quantity consumed. Variables such as temperature, day length, inflow etc. are exogenous variables determined outside the model. There is an error term also added to catch up the variations that are not picked up through the other variables in the equation.

As described in chapter 2 the quantity supplied by the producers is based upon their marginal costs of producing. Since the marginal, based upon the merit order, is supposed to reflect the price for the producer the price would be equal to marginal cost ($MC = P_{supply}$). When using the inverse supply function the general solution can be written as:

$$MC = P_{supply} = \alpha + \beta_1 * q + \beta_2 * Z + u$$

Where α is the constant variable which mathematically illustrates where the curve is intersected with the y-axis (the y-axis is here represented as the price). Or said in another way the intersection represents the quantity independent marginal cost. Example on such costs could be the start-/stop cost and maintenance costs that are not included in the model. β_1 is the coefficient for the endogen variable quantity, q, and β_2 is the coefficient for the exogenous variable Z. The error term is represented as u.

The demand function represents, as discussed in chapter 2, the willingness to buy a certain amount for a certain price.

$$q_{demand} = \alpha + \beta_1 * P + \beta_2 * Z + u$$

The α is here the constant coefficient, while β_1 and β_2 are respectively the coefficient for the endogenous price variable, P, and the exogenous variable, Z. u is the error term.

The variables price and quantity are as mentioned endogenous. This meaning that the explanatory variable is correlated with the error term. Due to the endogenity problem a standard OLS would be inconsistent and we need to use the two stage least squares with instruments to estimate the variables in our supply and demand functions. As written by Hills "… if we use a weak instrument, or an instrument that is invalid in the sense that it is not uncorrelated with the regression error, then IV estimation can be as bad, or worse, than using the least squares estimator"[18]. Therefor three tests are done together with the regression in Stata. Information about these test are gathered from the book "Principles of Econometrics" written by Hills [18]. The first test is the Hausman test for endogenity. The null hypothesis is that the correlation between the explanatory variable and the error term is equal to zero, and the alternative hypothesis is the contrary. The second test is the test for weak instruments. As stated by Hills: "A common rule of thumb is that if the F-test statistic takes a value less than 10, or if the t-statistic is less than 3.3, the instrument is weak"[18]. The third and last test is to test for the validity of the instrument. In order to be a valid instrument, the instrument has to be uncorrelated with the error term in the regression.

It was also found prof for heteroscedasticity and autocorrelation (HAC). HAC is therefore used and adjusted with 7 lags to catch up possible week variations.

6 Which factors do affect the price?

In order to estimate a good demand function, for a short time perspective, it is important to find out what factors that may be affecting the willingness to buy. The supply curve is in reality the marginal cost for the suppliers. So the question "what may affect the suppliers marginal cost?" is important to find a good estimate for the supply curve. The marginal cost will differ from different kinds of power generation. Therefore it will be divided into supply in a hydropower market, supply in a thermal market, and supply from wind power.

6.1 Supply hydro power (NO1)

The reservoir level may be a restriction and the reservoir level will therefore be an important factor of how much the producers are willing to supply. This will subsequently have an impact on the price. I have chosen to make a variable that is called "relative reservoir". This variable gives an indicator of how much water there is in the reservoir compared to an estimated normal reservoir level. Is the inflow this year so low that there might be a problem with lack of water in the reservoir, or on the contrary is there so much inflow so there is a potential threat for overflow? The relative reservoir variable is calculated as follows:

$$Relative\ reservoir = \frac{reservoir\ level}{normal\ reservoir}$$

Figure 11 for the effect of relative reservoir level compared to the price in NO1 illustrates an interaction between the relative reservoir level and the price. When the reservoir level is high, the prices are low, and when the reservoir level drops, the price is increasing. The irregularities in the price that are not captured in the relative reservoir filling, may be caused by factors such as the lack of transmission, high wind production etc.

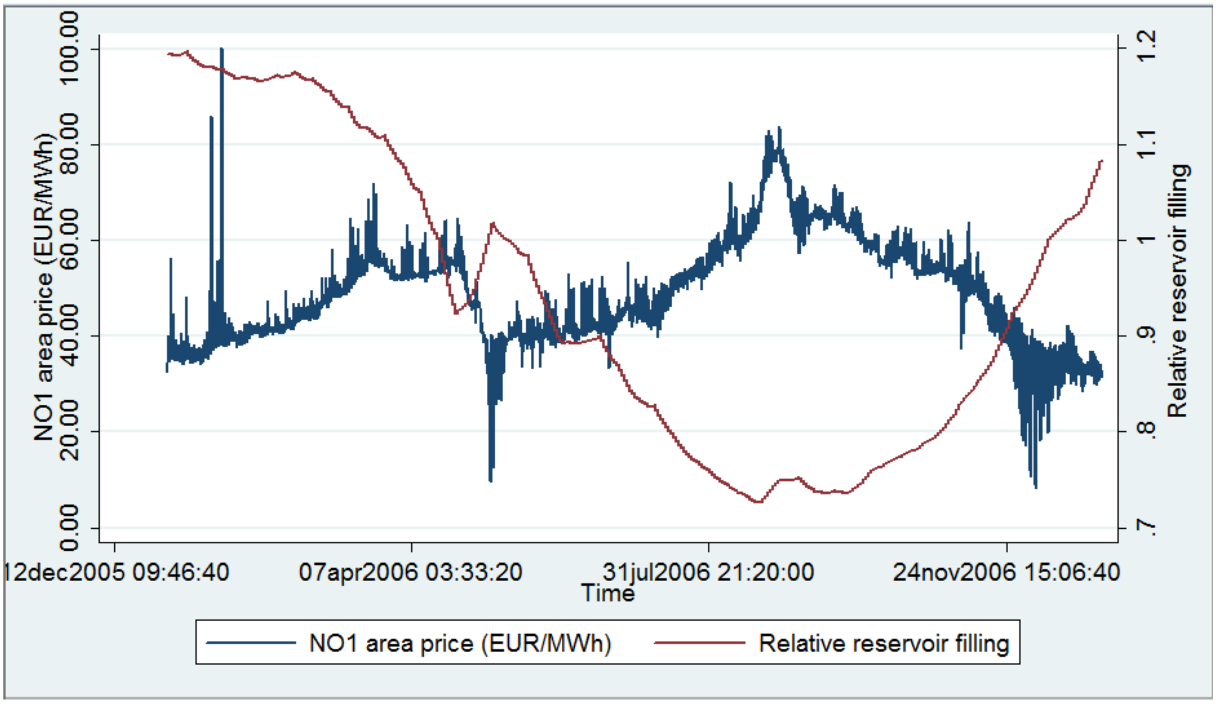

Figure 11: The graph is illustrating the interaction of price in NO1 and the relative reservoir filling. It is a clear inverse relationship between the to variables.

Variables such as the day length and daylight do capture the effect from increase in consumption because of the lack of daylight. These variables were tested in the estimation, but daylight was only significant for a few hours during the day, and is therefore not included/it is rejected. The day length was proven to be significant and this has been included as a variable in the estimation of the supply curve. I have used the day length which is calculated for Oslo, since there will not be much difference for the day length overall in NO1.

Even though Norway has not a thermal producing power industry, variables such as oil prices and coal prices are affecting the supply curve set by the Norwegian suppliers. Since NO1 prices are connected to countries with high share of thermal power the prices in NO1 would then also be affected by these inputs prices. Since the price of coal and the price of oil are to some extent correlated, se figure 12, both may not be included in the estimation. The oil price is included in the estimated supply curve in chapter 7. After the carbon certificates were implemented the marginal costs for the thermal producers were affected. Since the CO_2 allowances have an impact on the marginal cost it will then result in a price effect. The CO_2 dummy indicates whether the allowances were utilized at the given hour, or not. This has been proven overall insignificant, but it is still included in the estimated supply curve because of the dependence between the CO_2 dummy and the significant CO_2 price.

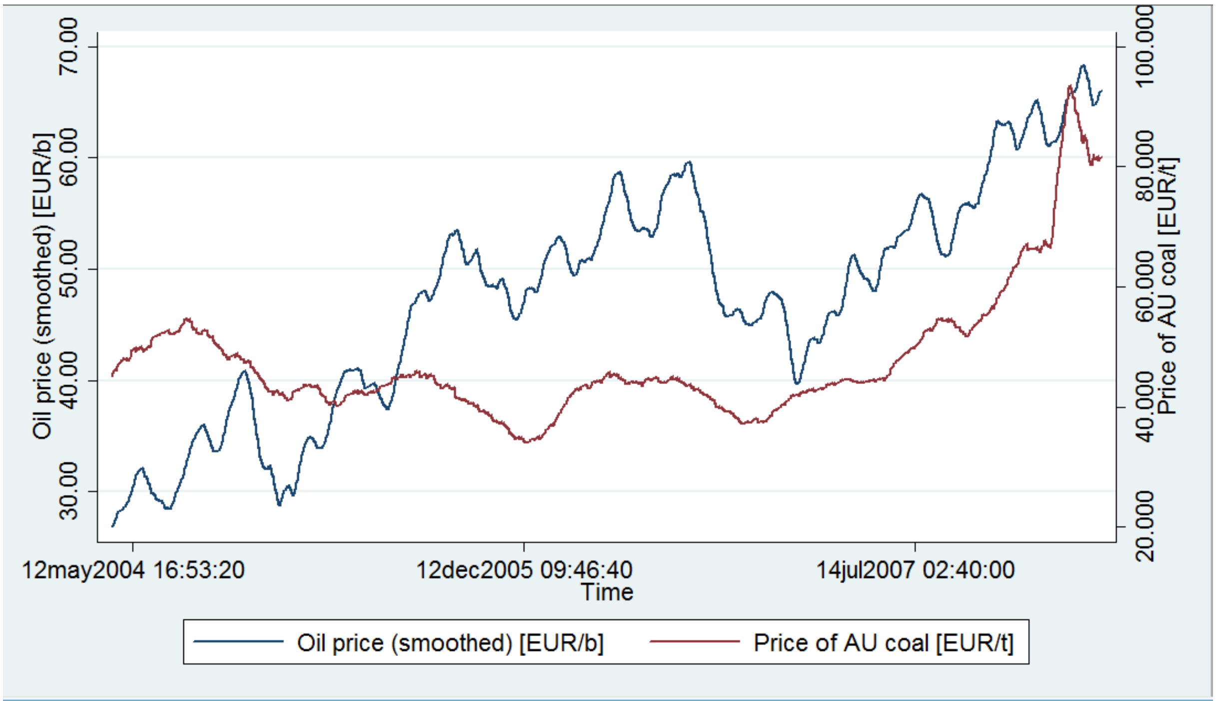

Figure 12: Price of coal and oil for the years 2004 to 2008. The graph illustrates the correlation of the two prices.

Tsin, tcos and trend is there to catch up the most of the systematics and trends in the exogenous variables like inflow and daylength_osl which may have certain patterns/cycles during a year. Trend is there to catch up the long term changes/patterns. IPI is the industrial production index, indicating the real production output, and is supposed to capture the variation in industry output over a business cycle. All of these variables are significant. Even though it sometimes during the estimation fluctuate between sinus and cosinus being significant, the two variables are never insignificant at the same time. Meaning one of them always captures the cycles variation.

6.2 Demand (NO1)

Price is a factor that most consumers react upon and is of clear significance in the Norwegian consumption pattern when tested.

Both daylight and day length for Oslo were also tested for the consumption estimation. It was shown that daylight was not significant for more than a few hours during the day, and was rejected as a variable. The day length for Oslo was significant and included.

Due to the fact that our consumption will vary based upon the day dummies such as holiday, summer vacation and week day are tested. The days we are not at work our consumption do change from industrial work to more private household consumption and the peak hours are somewhat shifted. The holiday dummy were over all insignificant and is rejected. Most likely the week day dummy capture some of the variation of the holiday dummy.

The substitution effect from electrical heating to other heating forms such as oil boilers are still in use in many households in Norway. The variable oil price is significant, and therefore included in the estimation.

One of the main factors for consumption, is the drop in temperature. This will especially affect the demand in Norway where the use of electricity for heating purposes is a large share of the total consumption. The variable heating degrees are used as an indication of the temperature effect since our need for heating is not really significant before temperature drops below 17^{o}C. The heating degree, for all temperatures measured below 17 degrees, will be calculated as follows; Heating degree = 17 ^{o}C minus the actual temperature for that hour.Since people's consumption of power are not linearly related to the rise in temperature, the heating degree will be more correct when assumed to be of a non-linear composition.

The variables sinus, cosinus and trend are, as explained for the Norwegian supply, implemented to catch the variation patterns.

6.3 Supply thermal power (DK1)

Even though some wind power is implemented in Denmark, a large share of the supply still comes from thermal power. The marginal cost for thermal power is high. The high marginal costs are caused by the high input prices for oil, coal and gas and by the inertia of the thermal power plants when starting and closing down the production. As discussed in chapter 6.1 the price of coal and price of oil are highly correlated. The variable, included in the supply function for DK1, is the price of coal. The CO_2 prices and dummy are also significant and included.

Both daylight and day length were tested for the same purpose as for supply in Norway. Both were found insignificant for the Danish supply.

The EEX-system prices were tested in the supply estimation, since Danish and Norwegian market is closely connected to European Energy Exchange (EEX) market through export and import. In addition the system price is based upon volume coupling in the Nordic regions. The price variable was decided to be kept out of the final estimation since it made too much noise in the estimation testing process.

The variables sinus, cosinus and trend are, as explained for the Norwegian supply, implemented to catch the variation patterns.

6.4 Demand (DK1)

The price was expected to be significant for the demand in DK1. Through the testing it was proven otherwise. This will be explained more thorough in chapter 7.2.

The heating degree for Copenhagen is a significant variable included in the estimation of the demand curve. For more explanation see chapter 6.2 for Norwegian demand. The heating degrees are based upon Copenhagen (which is located in DK2). The reason for this is of the lack of data collected in the temperature for the DK1 region. Since there is large holes in the data source for temperature an interpolation of this data makes not a very realistic scenario, and find the temperature of Copenhagen as a fairly good replacement for the simulations.

For the same reasons as explained for the Norwegian demand, variables such as summer in Denmark, bank holidays, and week days were tested. Since the bank holidays are almost identical in both Denmark and Norway, the same variable is being used. The summer holidays in Denmark are somewhat different from the Norwegian model. The summer holidays for Denmark, are spread over several weeks (from the first week in June until the last week in August). The week day variable is strongly significant.

Daylight and day length in Copenhagen were tested for the same purposes as described in the supply curve for NO1. Both daylight and day length were insignificant for almost all hours, and was then excluded.

The variables sinus, cosinus and trend are, as explained for the Norwegian supply, implemented to catch the variation patterns.

6.5 Supply wind power (DK1):

The supply for wind power is not included in this estimation process, but it is for sure implemented in the simulation process later on. The reason for not estimating this is because of the fact that Danish wind producers will be quite independent on other factors than the wind itself. The marginal costs are insignificant. And therefore when the wind is blowing, the producers do produce even if the price is low. Two exceptions are, if the wind speed is above 25m/s or if the price is highly negative (then the price needs to be even lower than the subsidy given, this rarely occurs).The wind production will not affect the marginal costs for the thermal supply, but in the end it will affect how much and when the thermal producers are able to produce.

7 Results from estimation

After many of different testing processes, as described in chapter 5.2, a final reasonable estimation was found. The final supply and demand equations for NO1 and DK1 are shown in chapter 7.1 and chapter 7.2 respectively. There are results from the estimation and testing process for all the 24 hours for each market in the appendix 12.3. One hour is picked out in the chapters below just to give an indication of the reasonability of the final supply and demand curves. All variables are described and listed in the table 2 found in chapter 5.1.

7.1 Supply and Demand NO1

After testing several different estimations the final variables shows clear significance and are indicating good results on the econometric testing. The supply equation is written as follows:

$$\boxed{\begin{aligned} lnp_{supplyNO1} = \gamma_0 + \gamma_1 * lnprod_{no1} + \gamma_2 * lnrelreservoir_{no1} + \gamma_3 * lnpoil + \gamma_4 \\ * lnco2_p + \gamma_5 * co2_d + \gamma_6 * trend + \gamma_7 * tsin + \gamma_8 * tcos + \gamma_9 * lnipi \end{aligned}}$$

The instruments that are used for supply NO1 are the log of heating degree for Oslo, squared logarithmic heating degree, dummy for the summer holiday in Norway, working days and day length in Oslo.

The result from estimation of supply in NO1 for one hour is shown in table 3 and table 4. Table 3 illustrates that all the variables are clearly significant at a 5% level in hour 8.

Table 3: The table illustrates the estimated supply for NO1 in hour 8. The P-values indicates that all variables are significant on 5% significance level.

lnprice_no1	Coef.	HAC Std. Err.	z	P>|z|	[95% Conf.	Interval]
lnprod_no1	.3702667	.0351879	10.52	0.000	.3012997	.4392338
lnrel_rese~1	-2.907995	.2015246	-14.43	0.000	-3.302976	-2.513014
lnpoil	1.59542	.2142031	7.45	0.000	1.17559	2.015251
lnco2_p	.1722442	.0826067	2.09	0.037	.0103381	.3341503
co2_d	-.6104105	.2128464	-2.87	0.004	-1.027582	-.1932392
trend	-.0007311	.0001208	-6.05	0.000	-.0009678	-.0004944
tsin	.2589149	.042906	6.03	0.000	.1748207	.343009
tcos	.2961726	.036908	8.02	0.000	.2238343	.368511
lnipi	.7974092	.3359994	2.37	0.018	.1388625	1.455956
_cons	-8.398744	1.93321	-4.34	0.000	-12.18777	-4.609721

```
Instrumented:  lnprod_no1
Instruments:   lnrel_reservoir_no1 lnpoil lnco2_p co2_d trend tsin tcos lnipi
               lnheatdeg_osl lnheatdeg_osl_2 dsumm dwkday lndlength_osl
HAC VCE:       Bartlett kernel with 7 lags
```

The econometric tests are illustrated in table 3. The rule of thumb is that if the F value shall be greater than 10. In hour 8 the F value for log of production in NO1 is way beyond this value. The conclusion is therefore that we have strong instruments. The test for endogenity is giving a p-value closely to zero, which means that we do have endogenous variables. Since the p-value for the overidentifying restrictions are higher than 0.05 it means that we do have valid instruments.

Table 4: The table illustrates the econometric test used on the estimation of supply in NO1 for hour 8.

First-stage regression summary statistics

Variable	R-sq.	Adjusted R-sq.	Partial R-sq.	HAC F(5,1449)	Prob > F
lnprod_no1	0.8480	0.8466	0.6928	347.113	0.0000

```
HAC VCE:       Bartlett kernel with 7 lags


Tests of endogeneity
Ho: variables are exogenous

HAC score chi2(1)              =   16.027  (p = 0.0001)
  (Prewhitening performed with 1 lag)

HAC regression F(1,1452)       =  22.2716  (p = 0.0000)
  (Based on Bartlett kernel with 7 lags)


Test of overidentifying restrictions:

Score chi2(4)         =  1.53314  (p = 0.8208)
  (Prewhitening performed with 1 lag)
```

The same are done for the demand function for NO1. The most reasonable result were made by the following demand equation:

$$lnq_{demandNO1} = \beta_0 + \beta_1 * lnprice_{no1} + \beta_2 * lnheatdeg_{osl} + \beta_3 * (lnheatde_{osl})^2 + \beta_4 * dsumm + \beta_5 * dwkday + \beta_6 * lnpoil + \beta_7 * trend + \beta_8 * tsin + \beta_9 * tcos + \beta_{10} * lnipi + \beta_{11} * lndlength_{osl}$$

Instruments used for the demand of NO1 are the relative reservoir in NO1, log of the carbon spot price and the dummy for the carbon market.

The result from estimation of demand in NO1 for one hour is shown in table 5 and table 6. Table 5 illustrates that almost all the variables are clearly significant at a 5% level in hour 8 except for the log of the day length, variable in Oslo. Even though it is proven to be insignificant in this hour, it is still significant in several of the hours, and is decided to be kept in the model.

Table 5: The table illustrates the estimated demand for NO1 in hour 8. The P-values indicates that almost all variables are significant on 5% significance level except for "lndaylength".

lncons_no1	Coef.	HAC Std. Err.	z	P>|z|	[95% Conf.	Interval]
lnprice_no1	-.0448742	.0079141	-5.67	0.000	-.0603856	-.0293629
lnheatdeg_-1	-.073013	.0092841	-7.86	0.000	-.0912095	-.0548164
lnheatdeg_-2	.0485028	.0026972	17.98	0.000	.0432164	.0537892
dsumm	-.0412094	.0114214	-3.61	0.000	-.063595	-.0188238
dwkday	.2097883	.0034416	60.96	0.000	.2030429	.2165337
lnpoil	.1901415	.0222826	8.53	0.000	.1464684	.2338147
trend	-.0000761	.000015	-5.08	0.000	-.0001054	-.0000467
tsin	.0681692	.0056275	12.11	0.000	.0571394	.079199
tcos	.1676938	.0278802	6.01	0.000	.1130496	.222338
lnipi	.2467999	.0377821	6.53	0.000	.1727482	.3208515
lndlength_-1	.002698	.0517254	0.05	0.958	-.098682	.104078
_cons	7.33508	.2169911	33.80	0.000	6.909785	7.760374

```
Instrumented:  lnprice_no1
Instruments:   lnheatdeg_osl lnheatdeg_osl_2 dsumm dwkday lnpoil trend tsin tcos
               lnipi lndlength_osl lnrel_reservoir_no1 lnco2_p co2_d
HAC VCE:       Bartlett kernel with 7 lags
```

The econometric tests are illustrated in table 5 for hour 8. In hour 8 the F is greater than 10 and indicates that the instruments are strong. The test for endogenity is giving us a p-value equal to zero, which means that we do have endogenous variables. Since the p-value for the overidentifying restrictions are higher than 0.05 it means that we do have valid instruments.

Table 6: The table illustrates the econometric test used on the estimation of demand in NO1 for hour 8.

First-stage regression summary statistics

Variable	R-sq.	Adjusted R-sq.	Partial R-sq.	HAC F(3,1449)	Prob > F
lnprice_no1	0.6978	0.6951	0.5864	71.3409	0.0000

HAC VCE: Bartlett kernel with 7 lags

```
Tests of endogeneity
Ho: variables are exogenous

HAC score chi2(1)             =  35.1835  (p = 0.0000)
  (Prewhitening performed with 1 lag)

HAC regression F(1,1450)      =  37.8251  (p = 0.0000)
  (Based on Bartlett kernel with 7 lags)


Test of overidentifying restrictions:

Score chi2(2)          =  4.43178  (p = 0.1091)
  (Prewhitening performed with 1 lag)
```

7.2 Supply and Demand DK1

The simulation of the Danish market did not go as smooth as for the Norwegian market. After many reconsiderations of different variables, instruments and approaches the following supply and demand equations were the ones giving most reasonable results. The estimation of supply showed to give some strange results for the first hours during the day. One explanation for the results may be the inertia of the thermal power stations when starting up the production. The equation for the supply is given as follows:

$$P_{supplyDk1} = \delta_0 + \delta_1 lngen_{dk1thermal} + \delta_2 * lnpcoal + \delta_3 * lnco2_p + \delta_4 * co2_d + \delta_5 * trend + \delta_6 * tsin + \delta_7 * tcos$$

Instruments used for the supply in DK1 are dummy for working days, log of heating degree for Copenhagen, the squared logarithmic heating degree and the dummy for Danish summer holidays.

The result from estimation of supply in DK1 for one hour is shown in table 7 and table 8. Table 7 illustrates that almost all variables are significant at a 5% level in hour 8. One exception is the dummy for the carbon market. This dummy is not significant more than a few hours. Because of the dependency between the CO_2 dummy and the CO_2 spot price, which are significant, the dummy is kept in the model.

Table 7: The table illustrates the estimated supply for DK1 in hour 8. The P-values indicates that almost all variables are significant on 5% significance level except for the dummy variable for the carbon market.

lnprice_dk1	Coef.	HAC Std. Err.	z	P>|z|	[95% Conf.	Interval]
lngen_dk1_~1	1.229707	.1015266	12.11	0.000	1.030718	1.428695
lnpcoal	.9138394	.1713752	5.33	0.000	.5779502	1.249729
lnco2_p	.2483527	.1188547	2.09	0.037	.0154017	.4813037
co2_d	-.0244329	.3616027	-0.07	0.946	-.7331612	.6842954
trend	-.0005686	.0000858	-6.63	0.000	-.0007368	-.0004004
tsin	-.192471	.0298563	-6.45	0.000	-.2509883	-.1339537
tcos	-.2404373	.0507715	-4.74	0.000	-.3399477	-.1409269
_cons	-9.087446	1.041194	-8.73	0.000	-11.12815	-7.046743

```
Instrumented:  lngen_dk1_thermal
Instruments:   lnpcoal lnco2_p co2_d trend tsin tcos dwkday lnheatdeg_cph
               lnheatdeg_cph_2 dksumm
HAC VCE:       Bartlett kernel with 7 lags
```

Table 7 shows the results from the econometric testing process. The F value equal to 414.241 do clearly indicate very strong instruments in the estimation. There are also in the Danish supply shown proof of endogenous variables. The last test for overidentifying restrictions implies that we do not have valid instruments. It is important to remember that this is only for one specific hour and do not illustrate the estimations as a whole. For the rest of the hours see the overview in appendix 3. For several of the other hours the instruments are shown to be valid and this indicates the earlier explained problems with the first hours for thermal supply.

Table 8: The table illustrates the econometric test used on the estimation of supply in DK1 for hour 8. The last test proves that the instruments are not valid in this hour.

First-stage regression summary statistics

Variable	R-sq.	Adjusted R-sq.	Partial R-sq.	HAC F(4,1452)	Prob > F
lngen_dk1_-1	0.7056	0.7036	0.6364	414.241	0.0000

HAC VCE: Bartlett kernel with 7 lags

```
Tests of endogeneity
Ho: variables are exogenous

HAC score chi2(1)            =   8.8237  (p = 0.0030)
  (Prewhitening performed with 1 lag)

HAC regression F(1,1454)     =  8.72994  (p = 0.0032)
  (Based on Bartlett kernel with 7 lags)


Test of overidentifying restrictions:

Score chi2(3)          =  11.9682  (p = 0.0075)
  (Prewhitening performed with 1 lag)
```

The last estimated equation is the demand in DK1. There were a lot of problems getting a good estimation for the demand curve in DK1. After a lot of testing we needed to go with a different approach than first thought. We then concluded that the price in the DK1 market was clearly not significant for the consumption. (It was proven not to be significant for any of the 24 hours). This implies that we have a perfectly inelastic demand for electricity in the Danish market, meaning we have a vertical demand curve.

The first estimated equation for demand in DK1 looked as follows:

$$q_{demandDK1} = \varepsilon_0 + \varepsilon_1 * lnprice_{dk1} + \varepsilon_2 * lnheatdeg_{cph} + \varepsilon_3 * \left(lnheatdeg_{cph}\right)^2 + \varepsilon_4 * dwkday + \varepsilon_5 * dksumm + \varepsilon_6 * trend + \varepsilon_7 * tsin + \varepsilon_8 * tcos$$

The instruments used were log of the coal price, log of the carbon spot price and the dummy for the carbon market.

The results found of the estimations are shown in the table 9. The log of price was clearly not significant for the 8th hour. This was the case for all of the 24 hours. And the estimated model was therefore rejected and replaced by a price independent model.

Table 9: The table shows the estimation of the demand in DK1. This shows that with the first estimated model the price is shown not to be significant.

lncons_dk1	Coef.	HAC Std. Err.	z	P>|z|	[95% Conf.	Interval]
lnprice_dk1	.0177832	.0238359	0.75	0.456	-.0289342	.0645007
lnheatdeg_~h	-.0473293	.0139385	-3.40	0.001	-.0746483	-.0200103
lnheatde~h_2	.019965	.0055383	3.60	0.000	.0091101	.0308199
dwkday	.4023622	.0180144	22.34	0.000	.3670547	.4376697
dksumm	-.0832407	.0171007	-4.87	0.000	-.1167573	-.049724
trend	.0000156	8.82e-06	1.77	0.077	-1.69e-06	.0000329
tsin	.0029878	.0065953	0.45	0.651	-.0099388	.0159144
tcos	.0776528	.0109799	7.07	0.000	.0561326	.099173
_cons	7.49242	.071519	104.76	0.000	7.352245	7.632594

Instrumented: lnprice_dk1
Instruments: lnheatdeg_cph lnheatdeg_cph_2 dwkday dksumm trend tsin tcos lnpcoal lnco2_p co2_d
HAC VCE: Bartlett kernel with 7 lags

In 2006 Norway had a net electricity consumption of 111.1TWh, Sweden had 135.5TWh, Finland had 86.8TWh and Denmark had only 35TWh [19]. A report written by Koreneff et al. indicates some of the reason for the low electricity demand in Denmark compared to the other Nordic countries. He writes: “The country itself is smaller by land area, with substantially smaller electricity use; net consumption of electricity is about 35 TWh, only one fourth of that in Sweden.”[19]. The electricity is considered a necessity. This implies that if the price rises the consumers will not lower their consumption in the same ratio as the price increases. For the Danish market simulated here it means that they, in the short run, will not lower their consumption at all if the price rises. Koreneff et al., [19], also discuss the use of energy. Norway is a good example of a country using electricity as a heating source while Denmark is using more thermal power for heating purposes. This means that the electricity used is mainly for light purposes, and other electronic articles. This also strengthens the understanding of why the price might not be a clear significant variable affecting the DK1 demand curve.

The function for the demand in DK1 is:

$$q_{demandDK1} = \varepsilon_0 + \varepsilon_2 * lnheatdeg_{cph} + \varepsilon_3 * \left(lnheatdeg_{cph}\right)^2 + \varepsilon_4 * dwkday + \varepsilon_5 * dksumm + \varepsilon_6 * trend + \varepsilon_7 * tsin + \varepsilon_8 * tcos$$

There is used a linear regression including HAC when estimating the new demand in DK1. In table 10 the new estimation of the demand are shown. Almost all variables used are significant at a 5% significance level in hour 8. One exception is the trigonometric sinus cycle. Still the “tsin” is significant for several hours and are still kept in the model. As explained in chapter 6.1 as long as either tcos or tsin is significant in a specific hour the variation due to cycles are still taken into account.

Table 10: The table shows the estimation of the DK1 demand in hour 8.

Regression with Newey-West standard errors
maximum lag: 7

Number of obs = 1463
F(7, 1455) = 1433.88
Prob > F = 0.0000

lncons_dk1	Coef.	Newey-West Std. Err.	t	P>|t|	[95% Conf.	Interval]
lnheatdeg_~h	-.0523176	.0120098	-4.36	0.000	-.0758759	-.0287593
lnheatde~h_2	.0227629	.0042398	5.37	0.000	.0144461	.0310798
dwkday	.4151118	.0045671	90.89	0.000	.406153	.4240707
dksumm	-.0879342	.0160952	-5.46	0.000	-.1195065	-.056362
trend	.000019	9.44e-06	2.01	0.044	4.75e-07	.0000375
tsin	-.0013525	.0045015	-0.30	0.764	-.0101825	.0074776
tcos	.0716587	.0107802	6.65	0.000	.0505124	.092805
_cons	7.539223	.0197224	382.27	0.000	7.500535	7.57791

8 Simulation of increasing wind power generation

The simulations with respect to the research question are simulated in the software program Matlab. The coding for the Matlab simulation is made by Olvar Bergland [20]. The simulations are using the estimated supply and demand made for NO1 and DK1 from chapter 7. Three base years have been used to simulate how the effect from wind power will influence different factors in the power market. There are four different simulated scenarios, and these will be shown in chapter 9. Chapter 8.1 will first introduce the restrictions done before simulating while chapter 8.2 informs about the basis years which the scenarios are compared to.

8.1 conditions for the simulations

From the report written by the Danish Ministry of Climate, Energy and Building [21], the planned total increase in installed capacity for wind power will be 1500MW (+500MW that are for trial production in offshore sector which would increase the total to 2000MW). The 1500MW installed capacity is divided into 1000MW offshore wind power and 500MW onshore[21]. The installation is planned in the year 2020. The installed capacity of wind power in Denmark by the end of 2011 was approximately 3871 MW[4]. The planned increase is then approximately 50 percent increase compared to the installed capacity by the end of 2011. The scenario simulated is based upon the reports planned increase to make the simulation close to a realistic scenario.

Even though the simulation is tried to be as realistic as possible some simplifications are done. But the simplifications that are made do not have any large significant impact on our simulation. The NorNed cable is not taken into account when calculating. The coal and oil prices are both set to a constant price of 60euros. The carbon spot price is set to 20 Euros. One of the reasons to make this price constant is to be able to separate out the effect that actually is made caused by the increase in wind generation. The industrial production index for Norway (ipi) is set to a value of 100, while the trend is based upon the value in 2011, which was 2000, and the variable is increased by one for each day. The maximum storage capacity in NO1 are set to be 55 630 GWh.

8.2 The base years

The basis years are 2009, 2010 and 2011. The year 2009 is considered as a normal year regarding the inflow rate. Year 2010 is a dry year, while 2011 is a very wet year. The purpose of using three different types of inflow rates is to be able simulate how this would affect the reservoir levels and the hydropower producers. A question raised could be; if it is a year with high inflow, will the increase in wind power cause overflow of water? Three different initial reservoir levels are also used. There is used an initial reservoir level of 50 percent, one with 65 percent, and one with 80 percent. The base year's key variables are listed in tables in appendix 3.

A comparison will be done between the new scenario, and the basis year, when the scenarios are simulated. Factors such as the prices in the two markets, the change in system price, consume-, producer- and social surplus, and the reservoir levels will be the main focus.

Two big simulations have been made. In the first simulation, we have transmission capacity between NO1 and DK1 set to 1000GW (todays capacity). In the second simulation, the transmission capacity has been increased to 4000GW for the purpose of seeing what happens if there are no bottlenecks in the transmission capacity.

A total of nine simulations have been done for each increase in wind power, and this is done twice because of the change in transmission capacity. This makes a total of 18 simulations for each simulated increase in wind power (three base years times three reservoirs levels times two transmission capacities make a total of 18). Due to the large amount of data the important factors for some of the scenarios are chosen. The rest of the results are made available as two electronic attachments.

9 Simulation 1

The simulations done in chapter 9 are done using a transmission capacity of 1000GW on the interconnector between NO1 and DK1.

9.1 Scenario: wind power 20% increase

The first simulated set of scenarios is a 20% increase in wind power generated in DK1 in compared to the base years. All other input variables, except for reservoir level and inflow as explained in chapter 8.2, are kept unchanged.

Table 13 gives an overview of the change in system prices and area prices for NO1and DK1 under the scenario of 20% increase in total installed wind capacity. The result are pretty clear from the simulations; if the wind power is increasing the prices are decreasing, both the system and area prices. The price is decreasing even though there is a wet or dry year, or high or low initial reservoir level. In the simulation results there are no overflow of water for the dry or normal base years. The wet year on the other hand will have overflow of energy, shown in tables 11 and 12 below. Table 11.1 is the amount of lost energy due to overflow, while table 12 is the overflow loss calculated into Euros. The tables conclude that when there already are overflow in the system with increasing wind power the amount of water “thrown away” is then also increasing.

Table 11: The table shows the amount of loss in energy due to overflow (TWh)

Over flow energy (TWh)	base year - wet	simulated year - wet	change
Intital reservoir level 50%	0	0	0
Intital reservoir level 65%	3.122	3.547	0.425
Intital reservoir level 80%	7.843	8.411	0.569

Table 12: Table shows the over flow loss (mill EUR)

Over flow loss (mill EUR)	base year - wet	simulated year - wet	change
Intital reservoir level 50%	0	0	0
Intital reservoir level 65%	37.714	42.448	4.734
Intital reservoir level 80%	86.757	92.361	5.604

Since there is proof for increase in the amount of overflow and the prices are decreasing the next step will be to take a look at the producer and consumer surplus. Who is benefitting from the increase in wind power and who is losing? The change in consumer surplus is in all of the nine different simulations increased in both markets as the wind power increases, see table 14.

Based on the theory in chapter 2 the consumer surplus will increase when the price is decreasing. The ones losing on the increase in wind power are the thermal producers in DK1 and the hydro power producers in the NO1. For a normal inflow based year and an initial reservoir level at 65% the producers negative change in revenue are 40.874 million Euros. The thermal producers are at the same time having a negative change in revenue with 3.843 million Euros. The large negative welfare changes for the Norwegian producers are greater than the positive changes in the surplus for the Norwegian consumer. So the total welfare in NO1 will be decreasing as the wind power generation is increasing, even though there is low initial reservoir levels or if there is a dry year. The market DK1 also has some negative changes for the thermal producers, but not to the same extent as the Norwegian producers. Since the positive change in producer surplus for the wind power plants and the positive change for the consumers in the DK1 market the total social welfare in DK1 are increasing. The net welfare change is increasing for all simulated scenarios.

Table 13: System price and area prices compared to the base years. 20% increase in generated wind power.

	Dry base year (inflow NO1 = 78.420TWh)	Normal base year (Inflow NO1 =	Wet base year (inflow NO1 = 110.760TWh)
Initial reservoir level 50% and wind generation increase 20%			
Base SYS price (EUR/MWh)	70.913	52.465	36.700
SYS price (EUR/MWh)	70.292	52.092	36.310
Base NO1 price (EUR/MWh)	95.701	59.193	42.383
NO1 price (EUR/MWh)	95.414	58.973	42.192
Base DK1 price (EUR/MWh)	37.147	38.655	26.048
DK1 price (EUR/MWh)	35.710	37.573	24.687
--	----------------------------	----------------------------	----------------------------
Initial reservoir level 65% and wind generation increase 20%			
Base SYS price (EUR/MWh)	40.557	31.606	20.875
SYS price (EUR/MWh)	40.050	31.215	20.668
Base NO1 price (EUR/MWh)	42.020	31.717	21.077
NO1 price (EUR/MWh)	41.588	31.373	20.936
Base DK1 price (EUR/MWh)	33.284	33.421	23.345
DK1 price (EUR/MWh)	32.008	32.401	22.067
--	----------------------------	----------------------------	----------------------------
Initial reservoir level 80% and wind generation increase 20%			
Base SYS price (EUR/MWh)	27.639	20.897	14.464
SYS price (EUR/MWh)	27.040	20.628	14.283
Base NO1 price (EUR/MWh)	27.946	20.691	14.389
NO1 price (EUR/MWh)	27.369	20.454	14.237
Base DK1 price (EUR/MWh)	27.661	28.677	20.225
DK1 price (EUR/MWh)	26.548	27.657	19.113
--	----------------------------	----------------------------	----------------------------

Table 14: Change in consumer- and producer surplus from three different base years. 20 % increase in wind generation.

	Dry base year (inflow NO1 = 78.420TWh)	Normal base year (Inflow NO1 = 92.684TWh)	Wet base year (inflow NO1 = 110.760TWh)
Initial reservoir level 50% and wind generation increase 20%			
Change CS in NO1 (mill EUR)	27.523	19.058	15.998
Change CS in DK1 (mill EUR)	30.071	23.276	30.596
Revenue hydro NO1 (mill EUR)	-31.952	-27.653	-25.631
Revenue wind DK1 (mill EUR)	23.699	25.464	15.907
PS thermal DK1 (mill EUR)	-6.399	-5.207	-3.825
NO1 welfare change (mill EUR)	-4.429	-8.595	-9.633
DK1 welfare change (mill EUR)	47.372	43.534	42.678
Net welfare change (mill EUR)	42.943	34.939	33.044
--	----------------------------	----------------------------	----------------------------
Initial reservoir level 65% and wind generation increase 20%			
Change CS in NO1 (mill EUR)	40.375	30.485	11.883
Change CS in DK1 (mill EUR)	26.671	21.936	28.820
Revenue hydro NO1 (mill EUR)	-46.195	-40.874	-21.698
Revenue wind DK1 (mill EUR)	22.071	21.880	14.110
PS thermal DK1 (mill EUR)	-5.445	-3.843	-3.135
NO1 welfare change (mill EUR)	-5.819	-10.389	-9.815
DK1 welfare change (mill EUR)	43.297	39.974	39.794
Net welfare change (mill EUR)	37.478	29.584	29.980
--	----------------------------	----------------------------	----------------------------
Initial reservoir level 80% and wind generation increase 20%			
Change CS in NO1 (mill EUR)	53.504	21.043	14.253
Change CS in DK1 (mill EUR)	23.612	23.227	25.093
Revenue hydro NO1 (mill EUR)	-60.547	-28.585	-25.187
Revenue wind DK1 (mill EUR)	18.372	17.191	12.444
PS thermal DK1 (mill EUR)	-4.163	-2.416	-2.051
NO1 welfare change (mill EUR)	-7.043	-7.543	-10.934
DK1 welfare change (mill EUR)	37.821	38.001	35.486
Net welfare change (mill EUR)	30.778	30.459	24.552

9.2 Scenario: wind power 50% increase

In the second simulated set of scenarios the generated wind power in DK1 is increased with 50% compared to the base years. All other input variables, except for reservoir level and inflow as explained in chapter 8.2, are kept unchanged.

Table 17 gives an overview of the change in system prices and area prices for NO1and DK1. The result indicates the same as for the lower increase in wind production. When increasing the amount of wind production, which consists of low marginal costs, the price in the market will decrease. This is also illustrated in the merit order in chapter 3. The prices will then decrease in both the system price and area prices.

Now there are inserted even more wind into the production, will we now blow even more water away in the NO1 market? The simulation result shows that there still will not be any overflow in the year with low initial reservoir level (50%) for the wet year, and there will not be any overflow in the dry and normal inflow year either. There is no doubt; the increase in wind power (with the set transmission capacity of 1000GW) will result in even more overflow for the hydropower producers in NO1. The amount of low in TWh and millions Euros are shown in the tables 15 and Table 16 respectively.

Table 15: The table shows the amount of loss in energy due to overflow (TWh)

Over flow energy (TWh)	base year - wet	simulated year - wet	change
Intital reservoir level 50%	0	0	0
Intital reservoir level 65%	3.122	4.207	1.085
Intital reservoir level 80%	7.843	9.290	1.447

Table 16: Table shows the over flow loss (mill EUR)

Over flow loss (mill EUR)	base year - wet	simulated year - wet	change
Intital reservoir level 50%	0	0	0
Intital reservoir level 65%	37.714	49.774	12.060
Intital reservoir level 80%	86.757	100.762	14.005

The same allocation of the change in consumer and producer surplus is proven in the 20% increase in wind power. With even more wind power (50% increase) the hydropower and the thermal power suppliers are losing producer surplus, while the wind power producers are gaining surplus, see table 18. The consumers are increasing their surplus in both markets. For a normal inflow based year and an initial reservoir level of 65% the hydro power producers negative change in revenue is 101.748 million Euros. The thermal producers do have a negative change in revenue of 9.060 million Euros. The large negative welfare changes for the Norwegian producers are still greater than the positive changes in the surplus for the Norwegian consumers. So the total welfare in NO1 will be decreasing as the wind power generation is increasing. This is the case even if there is low initial reservoir levels and/or if there is a dry year. The market DK1 also has some negative changes for the thermal producers, but not to the same extent as the Norwegian producers. Since there are a positive change in producer surplus for the wind power plants and a positive change for the consumers in the DK1 market, the total social welfare in DK1 is increasing. The total welfare change and the net social welfare for the two markets are increased by over 100 % when looking at the increase in wind power 20% to 50%.

Table 17: System price and area prices compared to the base years. 50% increase in generated wind power.

	Dry base year (inflow NO1 = 78.420TWh)	Normal base year (Inflow NO1 = 92.684TWh)	Wet base year (inflow NO1 = 110.760TWh)
Initial reservoir level 50% and wind generation increase 50%			
Base SYS price (EUR/MWh)	70.913	52.465	36.700
SYS price (EUR/MWh)	69.399	51.538	35.726
Base NO1 price (EUR/MWh)	95.701	59.193	42.383
NO1 price (EUR/MWh)	95.056	58.655	41.915
Base DK1 price (EUR/MWh)	37.147	38.655	26.048
DK1 price (EUR/MWh)	33.500	35.970	22.699
--	----------------------------	----------------------------	----------------------------
Initial reservoir level 65% and wind generation increase 50%			
Base SYS price (EUR/MWh)	40.557	31.606	37.714
SYS price (EUR/MWh)	39.356	30.634	49.774
Base NO1 price (EUR/MWh)	42.020	31.717	51.324
NO1 price (EUR/MWh)	41.026	30.865	51.659
Base DK1 price (EUR/MWh)	33.284	33.421	92.260
DK1 price (EUR/MWh)	30.061	30.924	92.862
--	----------------------------	----------------------------	----------------------------
Initial reservoir level 80% and wind generation increase 50%			
Base SYS price (EUR/MWh)	27.639	20.897	14.464
SYS price (EUR/MWh)	26.198	20.213	14.033
Base NO1 price (EUR/MWh)	27.946	20.691	14.389
NO1 price (EUR/MWh)	26.571	20.088	14.033
Base DK1 price (EUR/MWh)	27.661	28.677	20.225
DK1 price (EUR/MWh)	24.879	26.173	17.539
--	----------------------------	----------------------------	----------------------------

Table 18: Change in consumer- and producer surplus from three different base years. 50 % increase in wind generation.

	Dry base year (inflow NO1 = 78.420TWh)	Normal base year (Inflow NO1 = 92.684TWh)	Wet base year (inflow NO1 = 110.760TWh)
Initial reservoir level 50% and wind generation increase 50%			
Change CS in NO1 (mill EUR)	61.838	46.923	39.458
Change CS in DK1 (mill EUR)	76.954	57.690	74.861
Revenue hydro NO1 (mill EUR)	-71.814	-67.970	-63.441
Revenue wind DK1 (mill EUR)	47.208	56.835	28.533
PS thermal DK1 (mill EUR)	-14.351	-12.128	-8.536
NO1 welfare change (mill EUR)	-9.975	-21.048	-23.983
DK1 welfare change (mill EUR)	109.811	102.397	94.857
Net welfare change (mill EUR)	99.836	81.350	70.874
--	---------------------------	---------------------------	---------------------------
Initial reservoir level 65% and wind generation increase 50%			
Change CS in NO1 (mill EUR)	93.104	75.476	26.944
Change CS in DK1 (mill EUR)	67.723	53.490	69.954
Revenue hydro NO1 (mill EUR)	-106.909	-101.748	-51.114
Revenue wind DK1 (mill EUR)	44.905	49.025	25.555
PS thermal DK1 (mill EUR)	-12.279	-9.060	-7.011
NO1 welfare change (mill EUR)	-13.806	-26.272	-24.170
DK1 welfare change (mill EUR)	100.349	93.455	88.498
Net welfare change (mill EUR)	86.543	67.183	64.328
--	---------------------------	---------------------------	---------------------------
Initial reservoir level 80% and wind generation increase 50%			
Change CS in NO1 (mill EUR)	127.706	53.774	33.228
Change CS in DK1 (mill EUR)	58.876	56.646	59.980
Revenue hydro NO1 (mill EUR)	-144.747	-73.395	-60.340
Revenue wind DK1 (mill EUR)	37.928	37.459	23.533
PS thermal DK1 (mill EUR)	-9.509	-5.736	-4.926
NO1 welfare change (mill EUR)	-17.041	-19.621	-27.111
DK1 welfare change (mill EUR)	87.294	88.369	78.588
Net welfare change (mill EUR)	70.253	68.748	51.477

10 Simulation 2

The simulations done in chapter 10 are done using a transmission capacity of 4000 GW on the interconnector between NO1 and DK1.

The third simulated set of scenarios is a 20 % increase in wind power generated in DK1 compared to the base years with none or close to none transmission constraint. All other input variables, except for reservoir level and inflow as explained in chapter 8.2, are kept unchanged. The same is done in the fourth simulated set of scenarios. Only difference is that the increase in wind power is now set to 50 %. All of the results from these simulations are attached as electronic attachment. Over all the same changes occur as we saw in simulation 1, except for overflow in NO1. After increasing the transmission capacity the overflow are decreasing compared to the scenario with 1000 GW transmitted. There are still some overflow of water and the overflow are still increasing when increasing the wind power generated. This is shown in table 19 and 20 below. The system prices and area prices for the simulations are decreasing. The producer surplus does increase for the DK1 wind producers and decrease for the thermal producers. Hydropower producers in NO1 do still have a negative change in the producer surplus compared to the base year scenarios. The consumers in both markets are increasing their surplus.

Table 19: The table shows the amount of loss in energy due to overflow (TWh)

20% increase in wind			
Over flow energy (TWh)	**base year - wet**	**simulated year - wet**	**change**
Intital reservoir level 50%	0	0.599	0.599
Intital reservoir level 65%	2.086	2.891	0.805
Intital reservoir level 80%	5.595	6.503	0.907

Table 20: Table shows the over flow loss (mill EUR)

50% increase in wind			
Over flow energy (TWh)	**base year - wet**	**simulated year - wet**	**change**
Intital reservoir level 50%	0	1.598	1.598
Intital reservoir level 65%	2.086	4.111	2.025
Intital reservoir level 80%	5.595	7.892	2.296

It is also interesting to compare simulation 1 with lower transmission capacity than what was simulated here. There is shown three different simulations for the wind power increasing by

50 %. The first simulation (#1) in the table is showing the results when having low initial reservoir and low inflow through the year. The second simulation (#2) in the table do show what the result is becoming if we have high initial reservoir level and high inflow through the year. The third simulation (#3) is showing a scenario with normal inflow and 65 % initial reservoir level. This is done to illustrate the effect in extreme cases and the effect in a normal year. The three simulations are compared to the simulation done for the low transmission capacity in chapter 9.2 with the same amount of wind power (50%). Some are arguing that when built more interconnectors the price will go down in Norway, but is this really the case? Let's see.

Table 21: The effect of increasing transmission capacity from 1000 GW to 4000 GW. 50 % increase in wind power.

	#1	#1	#2	#2	#3	#3
	1000GW	4000GW	1000GW	4000GW	1000GW	4000GW
Key variable	Policy	Policy	Policy	Policy	Policy	Policy
NO1 production (TWh)	78.225	72.729	94.315	95.963	91.884	92.192
NO1 consumption (TWh)	86.241	88.539	90.198	90.181	87.725	87.779
DK1 production (TWh)	27.763	35.529	19.153	17.455	25.075	24.819
DK1 consumption (TWh)	21.580	21.580	21.425	21.425	21.416	21.416
SYS price (EUR/MWh)	69.399	46.666	14.033	14.053	30.634	30.267
NO1 price (EUR/MWh)	95.056	48.557	14.033	14.053	30.865	30.267
DK1 price (EUR/MWh)	33.500	43.047	17.539	14.053	30.924	30.266
-------------------------------	-----------	-----------	-----------	-----------	-----------	-----------
Net export NO1->DK1 (TWh)	-6.891	-14.686	2.670	4.336	0.561	0.815
Congestion rent (mill EUR)	539.734	192.532	49.753	0.000	51.767	0.042
Overflow energy (TWh)	0.000	0.000	9.290	7.892	0.000	0.000
Overflow loss (mill EUR)	0.000	0.000	100.762	87.102	0.000	0.000
Reservoir filling (TWh)	25.401	30.897	51.659	51.409	36.960	36.651
Reservoir filling (perc)	45.660	55.540	92.862	92.412	66.438	65.884

As illustrated in the table 21 when increasing the cable capacity and including an increased generation of wind power (50 %) the price effect are ambiguous. For scenario #1 with shortage of water the system price are decreased by the increase in transmission capacity. The same happens with the area price of NO1. But for DK1 the area price is increasing when increasing capacity in a dry year. Scenario #2 for a wet year with high initial reservoir level the system price is increasing with the increased transmission capacity. The NO1 area price is equal to the system price in this scenario, and will then obtain the same effect. The DK1 area price, for this scenario, will decrease with increased capacity. The overflow of energy is, as found earlier, decreasing with increased capacity. This is due to the possibility of exporting more power in a wet year when there are no bottlenecks in the system. The last scenario #3 is a normal inflow year with a reservoir capacity of 65 %. The system price is decreasing with the increased transmission capacity. The same will occur for the NO1 and DK1 area prices. To sum up the increase in transmission capacity does have a decreasing effect of the overflow loss, but the system price and area prices may both increase or decrease depending on the inflow and reservoir levels in the Norwegian market.

11 Conclusion

The results from the first simulation done shows that when looking at the effect made from increase in wind power, compared to the three basis years, both the system price and the area prices are decreasing. The consumer surplus is increasing in both DK1 and NO1. While the hydro and thermal producers revenues are decreasing. The producers of wind power have an increase in their producer surplus. Overflow do occur on years with high inflow, but an increase in wind power leads to an even greater increase in the amount of overflow.

The results from the second simulation with increase in the transmission capacity the price effect is not clear. There are made two different comparisons. For the comparison between the basis year with increased transmission capacity, and the same scenario with increase in wind power, the price in the markets are decreasing. The hydro power and thermal producers will still have negative changes in revenue. While the wind power producer will still increase their producer surplus. The amount of loss in energy due to overflow is decreasing when the capacity is “unlimited”. For the comparison between the initial 1000 GW transmission cable and the simulated 4000 GW, both with inclusion of 50 % increase in wind power, the price effect becomes ambiguous. The system price and area prices may both increase or decrease depending on the inflow and reservoir levels in the Norwegian market. The increase in transmission capacity does still have a decreasing effect of the overflow loss.

12 Literature:

1. Nord Pool Spot. *List of changes in Elspot Area*. 2008 [cited 2012 02.12]; 1-20]. Available from: http://www.nordpoolspot.com/Global/Download%20Center/Elspot/Elspot%20area%20change%20log.pdf.
2. Bøeng, A.C., *Konsekvenser for Norge av EUs fornybardirektiv.* Økonomiske analyser, 2010(4): p. 48-58.
3. energidirektorat, N.v.-o. *Om elsertifikatordningen*. 2011 06.12 [cited 2012 28.02]; Available from: http://www.nve.no/no/Kraftmarked/Elsertifikater/Om-elsertifikatordningen/.
4. Wilkes, J.M., Jacopo and M. Dragan, *Wind in power 2011 Europeans statistics*, 2012, The Eropean Wind Energy Association.
5. Lovdata. *LOV-1990-06-29-50*. 1990 [cited 2012 03.12]; Available from: http://lovdata.no/cgi-wift/wiftldles?doc=/app/gratis/www/docroot/all/nl-19900629-050.html&emne=energi*&&.
6. Norway, S. *Elektrisitetsstatestikk, månedlig*. 2012 [cited 2012 21.06]; Available from: http://www.ssb.no/emner/10/08/10/elektrisitet/tab-2012-06-11-01.html.
7. Førsund, F.R., *Hydropower economics*. 2007, New York: Springer. 261.
8. Innovasjon Norge, et al., *Fornybar energi 2007*, 2007.
9. Nord Pool Spot. *Price calculation*. 2012 [cited 2012 31.08]; Available from: http://nordpoolspot.com/How-does-it-work/Day-ahead-market-Elspot-/Price-calculation/]
10. Ministry Of Petroleum And Energy, *FOR-2002-05-07-448*, 2002: Lovdata.
11. Nord Pool Spot. *Bidding areas*. 2012 [cited 2012 03.10]; Available from: http://www.nordpoolspot.com/How-does-it-work/Bidding-areas/.
12. Statnett. *State of the Nordic Power System Map*. 2012 [cited 2012 08.08]; Available from: http://www.statnett.no/no/Kraftsystemet/Produksjon-og-forbruk/Kraftflyt-kart-Nordisk/.
13. Weather Underground. *Temperature data for Denmark and Norway in nphour.dta*. 2012; Available from: http://www.wunderground.com/?MR=1.
14. Norwegian Water Resources and Energy Directorate. *Inflow and reservoir levels for data set nphour.dta*. 2012; Available from: http://www.nve.no/no/Vann-og-vassdrag/.
15. Administration, U.S.E.I. *Oil prices for the data set nphour.dta*. 2012; Available from: http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
16. Eropean Central Bank. *Exchange rate from dollar to euro done for the data set nphour.dta*. 2012; Available from: http://www.ecb.int/stats/exchange/eurofxref/html/index.en.html.
17. Nord Pool Spot. *Historical data to the data set nphour.dta*. 2012; Available from: http://www.nordpoolspot.com/Market-data1/Downloads/Historical-Data-Download1/Data-Download-Page/.
18. Hill, R.C., W.E. Griffiths, and G.C. Lim, *Principles of Econometrics*. 3. ed. 2008, USA: John Wiley & Sons, Inc.
19. Koreneff, G., et al., *Future development trends in electricity demand.* 2009.
20. Bergland, O., *Professor at University of life sciences*, 2012.
21. Danish Ministry Of Climate, E.A.B., *Energy policy report 2012*, 2012, Climate and energy ministry. p. 1-17.

13 Appendix

13.1 Appendix 1 – Base years

Table for the different base years with different initial reservoirs levels are shown below. The increase in transmission capacity to 4000GW do not affect the base years in any way. (Except for the variable Average NO1-DK1 cap and vice versa will have 4000GW instead of 1000GW.)

Base years - initial reservoir 50%			
Key variable	**Normal year**	**Dry year**	**Wet year**
----------------------------	---------	----------	----------
Initial reservoir (perc)	50.0	50.0	50.0
Total NO1 inflow (TWh)	92.68	75.81	110.76
Total DK1 wind prod (TWh)	5.09	5.90	7.11
Other NO1 net export (TWh)	3.60	-1.12	1.45
Other DK1 net export (TWh)	4.22	-0.74	0.37
Average NO1 -> DK1 cap (GW)	1000.00	1000.00	1000.00
Average DK1 -> NO1 cap (GW)	1000.00	1000.00	1000.00
----------------------------	---------	----------	----------
Total NO1 production (TWh)	86.64	78.57	88.73
Total NO1 consumption (TWh)	85.56	86.19	86.67
Total DK1 production (TWh)	28.15	27.34	21.17
Total DK1 consumption (TWh)	21.42	21.58	21.42
Average SYS price (EUR/MWh)	52.46	70.91	36.70
Average NO1 price (EUR/MWh)	59.19	95.70	42.38
Average DK1 price (EUR/MWh)	38.65	37.15	26.05
----------------------------	---------	----------	----------
Total net export (TWh)	-2.52	-6.49	0.62
Congestion rent (mill EUR)	215.70	513.95	195.99
Total overflow (MWh)	0.00	0.00	0.00
Overflow loss (mill EUR)	0.00	0.00	0.00
Final reserve level (TWh)	33.86	25.05	49.84
Final reserve level (perc)	60.87	45.03	89.60
----------------------------	---------	----------	----------
CSx in NO1 (mill EUR)	0.00	0.00	0.00
CSx in DK1 (mill EUR)	0.00	0.00	0.00
Revenue hydro (mill EUR)	5303.10	7885.50	3815.65
Revenue wind DK1 (mill EUR)	183.02	202.68	170.57
PSx thermal DK1 (mill EUR)	88.58	68.30	38.59
----------------------------	---------	----------	----------

Base scenario - initial reservoir 65%			
Key variable	**Normal year**	**Dry year**	**Wet year**
-----------------------------	----------	----------	----------
Initial reservoir (perc)	65.0	65.0	65.0
Total NO1 inflow (TWh)	92.68	75.81	110.76
Total DK1 wind prod (TWh)	5.09	5.90	7.11
Other NO1 net export (TWh)	3.60	-1.12	1.45
Other DK1 net export (TWh)	4.22	-0.74	0.37
Average NO1 -> DK1 cap (GW)	1000.00	1000.00	1000.00
Average DK1 -> NO1 cap (GW)	1000.00	1000.00	1000.00
-----------------------------	----------	----------	----------
Total NO1 production (TWh)	92.62	83.87	92.47
Total NO1 consumption (TWh)	87.61	88.97	88.72
Total DK1 production (TWh)	24.22	24.81	19.48
Total DK1 consumption (TWh)	21.42	21.58	21.42
Average SYS price (EUR/MWh)	31.61	40.56	20.88
Average NO1 price (EUR/MWh)	31.72	42.02	21.08
Average DK1 price (EUR/MWh)	33.42	33.28	23.35
-----------------------------	----------	----------	----------
Total net export (TWh)	1.41	-3.97	2.31
Congestion rent (mill EUR)	50.92	92.44	64.60
Total overflow (MWh)	0.00	0.00	3.12
Overflow loss (mill EUR)	0.00	0.00	37.71
Final reserve level (TWh)	36.23	28.10	51.32
Final reserve level (perc)	65.12	50.51	92.26
-----------------------------	----------	----------	----------
CSx in NO1 (mill EUR)	0.00	0.00	0.00
CSx in DK1 (mill EUR)	0.00	0.00	0.00
Revenue hydro (mill EUR)	3068.41	3742.69	2019.36
Revenue wind DK1 (mill EUR)	160.80	184.03	152.73
PSx thermal DK1 (mill EUR)	65.16	58.60	30.28
-----------------------------	----------	----------	----------

Base years - Initial reservoir 80%			
Key variable	**Normal year**	**Dry year**	**Wet year**
----------------------------	----------	----------	---------
Initial reservoir (perc)	80.0	80.0	80.0
Total NO1 inflow (TWh)	92.68	75.81	110.76
Total DK1 wind prod (TWh)	5.09	5.90	7.11
Other NO1 net export (TWh)	3.60	-1.12	1.45
Other DK1 net export (TWh)	4.22	-0.74	0.37
Average NO1 -> DK1 cap (GW)	1000.00	1000.00	1000.00
Average DK1 -> NO1 cap (GW)	1000.00	1000.00	1000.00
----------------------------	----------	----------	---------
Total NO1 production (TWh)	97.80	89.81	96.10
Total NO1 consumption (TWh)	89.33	90.73	90.08
Total DK1 production (TWh)	20.77	20.64	17.22
Total DK1 consumption (TWh)	21.42	21.58	21.42
Average SYS price (EUR/MWh)	20.90	27.64	14.46
Average NO1 price (EUR/MWh)	20.69	27.95	14.39
Average DK1 price (EUR/MWh)	28.68	27.66	20.22
----------------------------	----------	----------	---------
Total net export (TWh)	4.86	0.21	4.57
Congestion rent (mill EUR)	77.85	48.80	56.78
Total overflow (MWh)	0.00	0.00	7.84
Overflow loss (mill EUR)	0.00	0.00	86.76
Final reserve level (TWh)	39.39	30.51	51.32
Final reserve level (perc)	70.81	54.84	92.26
----------------------------	----------	----------	---------
CSx in NO1 (mill EUR)	0.00	0.00	0.00
CSx in DK1 (mill EUR)	0.00	0.00	0.00
Revenue hydro (mill EUR)	2106.91	2634.58	1454.95
Revenue wind DK1 (mill EUR)	138.07	152.34	129.28
PSx thermal DK1 (mill EUR)	40.35	44.41	23.29
----------------------------	----------	----------	---------

13.2 Appendix 2: Do-file made for Stata. Estimating of supply and demand

```
/* MASTER THESIS CECILIE M. JONASSEN */
/* Supply and demand NO1 */
/* Natural logarithm */

set mem 128m
log using cj_ver5, replace

use "../data/nphour.dta", clear

tab year idx
tab year idz

drop if year>2011
keep if idz

di _newline

di "/SUPPLY & DEMAND NO1/"

di _newline

gen t = _n
sort t
tsset t
ipolate temp_osl t, generate(tempx_osl)
drop t
sort time
tsset time, clocktime delta(1 hour)

label var tempx_osl "temperature in Oslo"

di _newline

gen heatdeg_osl = 0
replace heatdeg_osl = (17-tempx_osl) if tempx_osl < 17
label var heatdeg_osl "Heating degree Oslo when tempx_osl<17"

gen lnheatdeg_osl = 0
replace lnheatdeg_osl = ln(heatdeg_osl) if heatdeg_osl > 1
label var lnheatdeg_osl "Log of heatingdegree in Oslo"

gen lnheatdeg_osl_2 = (lnheatdeg_osl)*(lnheatdeg_osl)
```

```
label var lnheatdeg_osl_2 "lnheatdeg_osl squared"

gen rel_reservoir_no1 = (1/no1_short)
label var rel_reservoir_no1 "Relative reservoir filling"

gen lnrel_reservoir_no1 = ln(rel_reservoir_no1)
list date year week day hour idz rel_reservoir_no1 if
lnrel_reservoir_no1==. & idz
tab year if lnrel_reservoir_no1==.
label var lnrel_reservoir_no1 "Log of relativ reservoir in
NO1"

gen lnprod_no1 = ln(prod_no1)
list date year week day hour idz prod_no1 if lnprod_no1==.
label var lnprod_no1 "log of prod_no1"

gen lnprice_no1 = ln(price_no1)
list date year week day hour idz price_no1 if lnprice_no1==.
//if price equal to zero in some hours --> fix it
replace lnprice_no1 = ln(0.01) if price_no1<0.01
label var lnprice_no1 "log of price_no1"

gen lnpcoal = ln(pcoal)
label var lnpcoal "log of pcoal"
gen lnpoil = ln(poil)
label var lnpoil "log of poil"

gen lnco2_p = 0
replace lnco2_p = ln(co2_p) if co2_p>1
sum lnco2_p
label var lnco2_p "log of co2_p"

gen lncons_no1 = ln(cons_no1)
list date year week day hour idz cons_no1 if lncons_no1==.
label var lncons_no1 "log of cons_no1"

gen lndlength_osl = ln(dlength_osl)
label var lndlength_osl "log of daylength in Oslo"

gen lngen_dk1_wind = 0
list date year week day hour idz gen_dk1_wind if
lngen_dk1_wind==. & idz
//if generation of wind is equal to zero in some hours --> fix
it
```

```
replace lngen_dk1_wind = ln(0.01) if gen_dk1_wind<0.01
replace lngen_dk1_wind = ln(gen_dk1_wind) if
gen_dk1_wind>=0.01
label var lngen_dk1_wind "Log of gen_dk1_wind"

gen lnprice_eexh = ln(price_eex)
//list date year week day hour idz price_eex if
lnprice_eexh==.
//if price equal to zero in some hours --> fix it
replace lnprice_eexh = ln(0.01) if price_eex<0.01
label var lnprice_eexh "Log of price_eex"

gen lnprice_eexd = ln(price_eexd)
list date year week day hour idz price_eexd if lnprice_eexd==.
//if price equal to zero in some hours --> fix it
replace lnprice_eexd = ln(0.01) if price_eexd<0.01
label var lnprice_eexd "Log of price_eexd"

gen lnipi = ln(ipi)

di _newline

//
// A number of tests for better testing
//
forvalues h = 1/24 {
  di _newline
  di "**************************************"
  di "*       Supply NO1 hour: " `h'
  di "**************************************"
  di _newline

  preserve
  keep if hour==`h' & idz
  sort date
  tsset date, daily
  tsreport, report report0 list

  ivregress 2sls lnprice_no1 lnrel_reservoir_no1 lnpoil
lnco2_p co2_d trend tsin tcos lnipi ///
    (lnprod_no1 = lnheatdeg_osl lnheatdeg_osl_2 dsumm dwkday
lndlength_osl), ///
    vce(hac bartlett 7)
```

```
  di _newline
  estat first

  di _newline
  estat endog

  di _newline
  estat overid

  restore
}

forvalues h = 1/24 {
  di _newline
  di "****************************************"
  di "*       Demand NO1 hour: " `h'
  di "****************************************"
  di _newline

  preserve
  keep if hour==`h' & idz
  sort date
  tsset date, daily
  tsreport, report report0 list

  ivregress 2sls lncons_no1 lnheatdeg_osl lnheatdeg_osl_2
dsumm dwkday lnpoil trend tsin tcos lnipi lndlength_osl ///
     (lnprice_no1 = lnrel_reservoir_no1 lnco2_p co2_d), ///
     vce(hac bartlett 7)

  di _newline
  estat first

  di _newline
  estat endog

  di _newline
  estat overid

  restore
}

di _newline
```

```
di "/SUPPLY & DEMAND DK1/"

di _newline

gen r = _n
sort r
tsset r
ipolate temp_cph r, generate(tempx_cph)
drop r
sort time
tsset time, clocktime delta(1 hour)

label var tempx_cph "temperature in Copenhagen"

gen heatdeg_cph = 0
replace heatdeg_cph = (17-tempx_cph) if tempx_cph < 17
label var heatdeg_cph "Heating degree Copenhagen when
tempx_cph<17"

gen lnheatdeg_cph = 0
replace lnheatdeg_cph = ln(heatdeg_cph) if heatdeg_cph > 1
label var lnheatdeg_cph "Log of heating degree in Copenhagen"

gen lnheatdeg_cph_2 = (lnheatdeg_cph)*(lnheatdeg_cph)
label var lnheatdeg_cph_2 "lnheatdeg_cph squared"

gen gen_dk1_thermal = (gen_dk1_cent + gen_dk1_decent)
label var gen_dk1_thermal "Generation of thermal power DK1
(both central and decentral)"

gen lngen_dk1_thermal = ln(gen_dk1_thermal)
list date year week day hour idz gen_dk1_thermal if
lngen_dk1_thermal==. & idz
label var lngen_dk1_thermal "Log of gen_dk1_thermal"
gen llngen_dk1_thermal = l.lngen_dk1_thermal

gen lnprice_dk1 = ln(price_dk1)
list date year week day hour idz price_dk1 if lnprice_dk1==.
//if price equal to zero in some hours --> fix it
replace lnprice_dk1 = ln(0.01) if price_dk1<0.01
label var lnprice_dk1 "Log of price_dk1"

gen lncons_dk1 = ln(cons_dk1)
list date year week day hour idz cons_dk1 if lncons_dk1==.
```

```
label var lncons_dk1 "Log of consumption in DK1"

gen lndlength_cph = ln(dlength_cph)
list date year week day hour idz dlength_cph if dlength_cph==.
label var lndlength_cph "Log of daylength in Copenhagen"

gen dksumm = (week >= 27) & (week <= 34)
di _newline

forvalues h = 1/24 {
  di _newline
  di "*******************************************************"
  di "*       Supply Thermal Power DK1 hour: " `h'
  di "*******************************************************"
  di _newline

  preserve
  keep if hour==`h' & idz
  sort date
  tsset date, daily
  tsreport, report report0 list

  ivregress 2sls lnprice_dk1 lnpcoal lnco2_p co2_d trend tsin
tcos ///
    (lngen_dk1_thermal = dwkday lnheatdeg_cph lnheatdeg_cph_2
dksumm), ///
    vce(hac bartlett 7)

  di _newline
  estat first

  di _newline
  estat endog

  di _newline
  estat overid

  restore
}

di _newline

forvalues h = 1/24 {
  di _newline
```

```
  di "*************************************"
  di "*       Demand DK1 hour: " `h'
  di "*************************************"
  di _newline

  preserve
  keep if hour==`h' & idz
  sort date
  tsset date, daily
  tsreport, report report0 list

  ivregress 2sls lncons_dk1 lnheatdeg_cph lnheatdeg_cph_2
dwkday dksumm trend tsin tcos ///
     (lnprice_dk1 = lnpcoal lnco2_p co2_d), ///
     vce(hac bartlett 7)

  di _newline
  estat first

  di _newline
  estat endog

  di _newline
  estat overid

  //
  // impose no price effect!
  //
  di _newline
  newey lncons_dk1 lnheatdeg_cph lnheatdeg_cph_2 dwkday dksumm
trend tsin tcos, lag(7)

  restore
}

log close
translate cj_ver5.smcl cj_ver5.ps, replace pagesize(a4)

exit
```