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System Analysis of Large-Scale Wind Power Integration in North-Western Europe

A study on the impact of large-scale wind power expansion and on the impact of a North Sea offshore grid

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Problem Description

Wind resources in North-Western Europe have a vast potential, and the wind conditions along the Norwegian coast are considered to be among the best in Europe. All of the countries neighbouring the North Sea have ambitious plans to build wind farms both on- and offshore.

It is of interest to investigate the impact such a massive expansion of wind power will have on the power system of North-Western Europe, with respect to other energy forms and to energy prices. Such an amount of offshore wind power may necessitate the creation of an offshore grid, allowing for interconnections between wind farms. An investigation into the effects of such an offshore grid will therefore also be in order.

The project will cover the following issues:
- Simulations of simplified power system scenarios set in the years 2005, 2020 and 2030.
- Study how an increasing amount of installed wind power will affect energy prices, power production distribution and power transmission flows.
- Investigate how an offshore grid consisting of interconnections between offshore wind farms will affect the system.

Assignment given: 18. January 2009
Supervisor: Terje Gjengedal, ELKRAFT

Summary

Problem description
The objective of this project was to create a simple model of the European power system and to investigate the effect an increasing amount of on- and offshore wind power will have on the North European power market in general and Norway in particular. The scenarios contain increasing amounts of installed wind power capacity, both on- and offshore. Emphasis was to be on the area surrounding the North Sea. The project covers the following issues:

- Simulations of simplified power system scenarios set in the years 2005, 2020 and 2030.
- Study how an increasing amount of installed wind power will affect energy prices, power production distribution, and power transmission flows.
- Investigate how an offshore grid consisting of interconnections between offshore wind farms will affect the system.

The task
The simulations in this project were performed using simple power market model. The model included 6 price areas: Denmark West, Denmark East, Norway, Sweden/Finland, Germany and UCTE/Others. The existing market model was modified in the following manner:

- Split Norway into three price areas: Norway North, Middle and South
- Add the Netherlands
- Add the United Kingdom
- Add corresponding offshore price areas for areas neighbouring the North Sea.

Wind series were generated for each wind generator using reanalysis data.

Scenarios were created for the years 2005, 2020 and 2030. In these scenarios, wind power capacities are increasing as time progresses. The 2020 and 2030 scenarios have been simulated with two alternative grid configurations: one where the offshore areas are connected only to their respective onshore areas and one where the offshore areas are also interconnected in an offshore grid. In total 7 different scenarios were simulated.

Results
Figure 1 shows that wind power is able to supplant a large share of energy originally produced by conventional thermal generators. The presence of an offshore grid does not have any dramatic effects on energy production for the system, though it is possible to conclude that the presence of an offshore grid may contribute to slightly shift the power system in favour of renewable energy sources.

Wind power will cause a significant reduction in energy prices in all areas, resulting in reduced energy costs for the entire system.

Analysis of lost wind and hydro power reveals the importance of sufficient transmission capacity when large quantities of wind power are added to the system. Scenario 4 features enormous quantities of lost hydro power in the North and Middle of Norway due to transmission limitations.

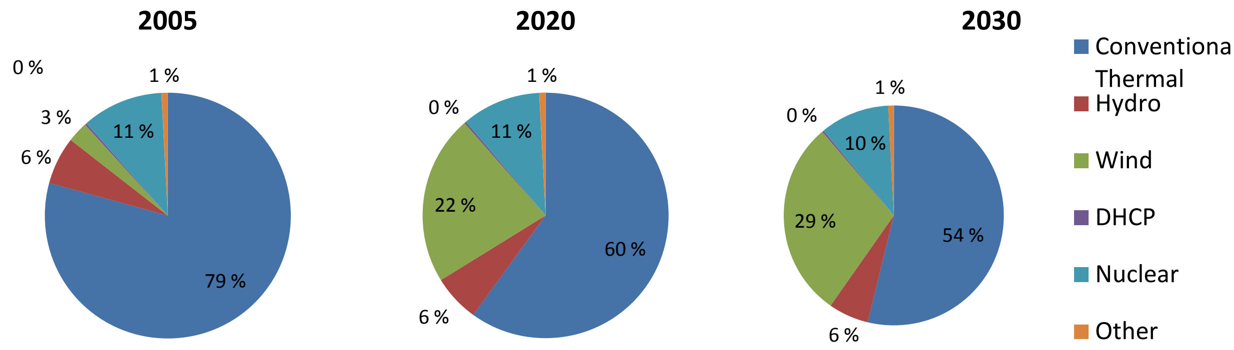


Figure 1: Percentage of yearly energy production by source.

Analyses of power transmissions reveal that the offshore grid is over-dimensioned. Rationalizing the grid by reducing transmission capacities to more realistic levels will give a more cost-effective solution. This was demonstrated by performing a quick simulation and analysis of a scenario featuring such a rationalized grid.

Wind power will cause more frequent variations in hydro power generation, due to balancing needs. Parts of the increased variability in the hydro generators can be explained by the increasing amount of wind power in the system, while other parts are most likely caused by limitations in the simulation model itself.

Conclusion

Given the number of assumptions made in the grid, in cost calculations and in the model at large, it is more important to focus on general trends than on concrete numerical values. However, it is clear that increasing the amount of on- and offshore wind power in the European power system will have a beneficial impact to society's energy costs. It is also clear that wind power has the potential to dramatically reduce CO_2-emissions caused by power generation.

The offshore grid seems to be more beneficial to the power producers than to consumers since it causes slightly higher energy prices and providing a measure of flexibility as to where offshore wind power production is sent.

Wind power will present challenges, especially regarding transmission grid development. A sufficiently dimensioned grid will be essential to the successful implementation of such amounts of wind power, both with respect to profitability and in order to avoid waste of potential wind or hydro energy.

Contents

1 Introduction

Europe has ambitious future goals for wind power expansion, both on- and offshore. Towards 2020 and 2030 it is expected that most European countries will integrate large amounts of wind power generation into their power systems. This will undoubtedly affect the European power system in a significant way.

The purpose of this project is therefore to shed some light on the consequences and results of these plans. Wind power's impact on such factors as energy prices and costs and on other power sources have been investigated.

The main focus of this project has been on North-Western Europe, more specifically on the countries surrounding the North Sea. The following countries have been modelled in some detail: Denmark, Norway, Sweden/Finland, Germany, the Netherlands and the United Kingdom. The rest of Europe has been treated as one price area. The numerous offshore wind farms and grid connections offer the possibility of creating an offshore transmission grid, consisting of interconnections between offshore wind farms. The effects of such an offshore grid have also been investigated with respect to the same power system factors as mentioned above.

Simulations have been performed using a simple power system model developed in MATLAB by Thomas Trøtscher for his master thesis "*Large-scale Wind Power integration in a Hydro-Thermal Power Market*" from 2008. The power system model has been expanded slightly to suit the scope of this project, and a script for further evaluating the simulation results was developed. Future wind power scenarios are mostly based on the *TradeWind* project by the European Wind Power Association. These two previous works form most of the basis for this project.

Factors like future load growth and expansion of other forms of generation have been disregarded in this project. This is bound to affect simulation results, and should be kept in mind when evaluating the results of this report.

2 Data processing and evaluation methods

This chapter describes some of the methods used to process input data used in the simulations and to evaluate simulation results.

2.1 Currencies

Marginal costs in the model are given in Danish Kroner (DKK) since it was originally made to evaluate the Danish power system. The mean currency values of 2005, according to DnB NOR [1], were:

Currency	EUR €	DKK	GBP £
Avg. against NOK in 2005	8.0070	107.45	11.7151

Table 1: Average currency values in 2005, according to dnbnor.no [1]

DKK will for the rest of this document be referred to as kroner, abbreviated kr. This gives the following currency factors:

$$k_{€\to DKK} = \frac{107.45\,\text{DKK}}{8.0070\,€} = 13.4195\,{}^{kr}\!/\!_{€} \qquad k_{£\to DKK} = \frac{107.45\,\text{DKK}}{11.7151\,€} = 9.1719\,{}^{kr}\!/\!_{£}$$

2.2 Generating wind series

Wind speed series were generated using reanalysis data for the period 2000 – 2006. This is the same time period that was used for generating the wind series that were already in the model. [2 pp. 22 - 23] The wind data series were then converted from speeds to per unit production, using the normalized power curves from the TradeWind report "*WP 2.6 - Equivalent Wind Power Curves*". [3 p. 10] These curves are designed to model the power curve of an entire wind farm, not individual turbines.

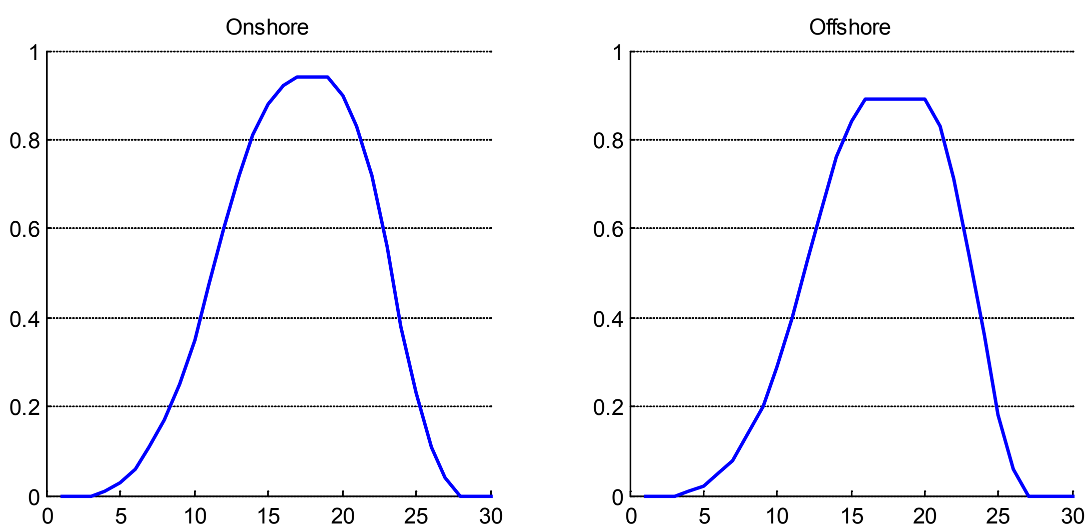


Figure 1: Normalized power curves for onshore and offshore wind farms

See *Appendix 1: TradeWind wind farm power* curves on page 55 for detailed information.

The resulting per unit power output series were evaluated with respect to utilization time. If utilization times were found to be too low, the series were scaled by an appropriate factor. It is for example expected that onshore wind farms in Norway will have an average utilization time of around 3000 hours, while onshore wind farms in Denmark are known to have utilization times between 2000 and 2500 hours. Likewise, it is expected that utilization times for offshore wind farms in the North Sea will bee somewhere between 3000 and 4000 hours.[4 p. 26] The scaling of the wind series is used to achieve this.

2.3 Calculating area and system prices and energy costs

Average yearly area prices are calculated by averaging hourly prices p_t in each area in the following manner:

$$\textit{Average yearly area price} = \frac{1}{8760} \cdot \sum_{t=1}^{8760} p_t \qquad \left[{}^{\mathrm{kr}}\!/_{\mathrm{MWh}}\right]$$

Total yearly energy costs are calculated by multiplying each hourly area energy price p_t with the corresponding load value for the same hour, l_t. By adding together the resulting hourly energy cost time series, the yearly energy cost per area is found. This is done in the following manner:

$$EC_{area} = \sum_{t=1}^{8760} \left(p_t \cdot l_t \right) \qquad [\mathrm{kr}]$$

The average yearly system price for the entire system is then found by dividing the total yearly energy costs of the system by the total yearly energy consumption of the system:

$$\textit{Average yearly system price} = \frac{\sum_{n=1}^{N} EC_n}{\sum_{n=1}^{N} E_n} \qquad [\mathrm{kr}]$$

N is the total number of price areas, EC_n is the total yearly energy costs of area n and E_n is the total yearly energy consumption of area *n*.

2.4 Calculating hydro power reservoir spillage and lost wind energy

By evaluating the amount of reservoir spillage and lost wind energy it is possible to determine whether hydro and wind generators are used optimally. Large quantities of lost energy in an area may indicate lacking export capabilities compared to installed power capacities.

For hydro generators, potential energy is lost when its reservoir runs over. In the model, reservoir overflow is assumed to occur whenever the reservoir is full and inflow is larger than the generator's current production. Simulations performed with the model generate the following data, which is used to evaluate whether reservoir overflow takes place or not:

- P_g – Power generation time series [MW]
- r_{max} – Maximum reservoir level [MWh]
- r – Reservoir level time series [MWh]
- P_{inflow} – Inflow time series [MWh/h]

This means that reservoir overflow $P_{overflow}$ for any given time is determined by the following logic:

$$\left(r = r_{\max}\right) \cap \left(P_{inflow} > P_g\right) \rightarrow P_{overflow} = P_{inflow} - P_g$$

If this statement is not true, then overflow during the hour in question is zero. All time series have a sample rate of 1 hour. This means that if $P_{overflow}$ = 100 MW during a given hour, then lost energy during that hour is 100 MWh.

For a wind generator, potential energy is lost whenever the generator's actual power output is lower than what is suggested by the current wind speed and the generator's power curve. As explained in chapter 2.2, wind series are given in per unit. This means that if the maximum rating of a wind farm is 500 MW and wind series value of a given hour is 0.5 p.u., then the maximum potential power output is 250 MW during that hour with a resulting energy production of 250 MWh. If the actual power output during that hour is lower than 250 MW, wind energy is lost. The following simulation output is used to evaluate whether wind energy is lost:

- P_{max} – Maximum rating of wind generator [MW]
- P_g – Power generation time series [MW]
- p_{wind} – Wind time series [p.u.]

The following logic is used to determine whether wind power output is below its maximum potential during a given hour:

$$P_{\max} \cdot p_{wind} > P_g \rightarrow P_{lost} = P_{\max} \cdot p_{wind} - P_g$$

2.5 Calculating yearly offshore grid cost

The TradeWind report "*Assessment of increasing capacity on selected transmission corridors*" describes a method of estimating the costs of offshore transmission cables. [5 pp. 101 - 103] The cost of a cable is calculated using the equation:

$$C = SC_{cable} \cdot l \cdot P_{cable} + SC_{conv} \cdot P_{conv}$$

SC_{cable} is the specific cost of the cable including laying, given in $\left[{}^{\text{mill.kr}}\!/\!_{\text{km}\cdot\text{MW}} \right]$. l is the length of the cable in km and P_{cable} is its rating in MW. SC_{conv} is the specific cost of converters (such as rectifiers and inverters) in ${}^{\text{mill.kr}}\!/\!_{\text{MW}}$. P_{conv} is the rating of the converter in MW.

SC_{cable} is assumed to be:

$$SC_{cable} = 2.1 \cdot 10^{-3} \left[{}^{\text{mill.€}}\!/\!_{\text{MW}\cdot\text{km}} \right] \approx 28.2 \cdot 10^{-3} \left[{}^{\text{mill.kr}}\!/\!_{\text{MW}\cdot\text{km}} \right]$$

Two values were available for SC_{conv}, a low cost alternative of 0.593 [mill.€/MW] and a low cost alternative of 0.324 [mill.€/MW]. In this project the average value of the two has been used:

$$SC_{conv} = \frac{0.593 + 0.324}{2} = 0.4585 \left[{}^{\text{mill.€}}\!/\!_{\text{MW}\cdot\text{km}} \right] = 6.1528 \left[{}^{\text{mill.kr}}\!/\!_{\text{MW}\cdot\text{km}} \right]$$

$$C = 0.00282 \cdot l \cdot P_{cable} + 6.1528 \cdot P_{conv}$$

Yearly costs of the offshore cable are then calculated with an annuity factor $\varepsilon_{t,p}$, which has an assumed discount rate p of 6% and a lifetime t of 30 years [6 p. 237]:

$$\varepsilon_{30,6} = \frac{\frac{p}{100}}{1 - \left(1 + \frac{p}{100}\right)^{-n}} = \frac{\frac{6}{100}}{1 - \left(1 + \frac{6}{100}\right)^{-30}} = 0.0726$$

The offshore grid costs are calculated including offshore to onshore cable connections and eventual interconnections between offshore wind farms.

3 About the model

The simulations in this project were performed using an updated version of the power market model developed in MATLAB by Thomas Trøtscher for his master thesis “*Large-scale Wind Power integration in a Hydro-Thermal Power Market*”. [2]

The model included the following six price areas: Denmark West, Denmark East, Norway, Sweden/Finland, Germany and UCTE/Others. Each area was fully equipped with all required information, such as:

- Area name
- Geographical placement (latitude and longitude)
- Load data
- Transfer constraints between areas
- Generators
    - Generation type
    - Maximum and minimum production capacity
    - Maximum reservoir capacity (hydro only)
    - Inflow data (hydro only)
    - Wind series (wind only)
    - DHCP generation data
    - Median reservoir levels (hydro only)
    - Overhaul schedules (thermal and nuclear)
    - Outage lists (not used)
    - Marginal generator costs

There are 6 different types of power generation in the model: Conventional thermal, hydro, wind, DCHP, nuclear and other. Conventional thermal, nuclear and DCHP generators have marginal costs determined by fuel prices, etc. Power prices from these generators are therefore determined by their marginal costs. Hydro power costs are determined by a water value function. Both hydro and wind power are assumed to have zero marginal costs in this model.

The data series load, inflow, wind, DHCP, median reservoir levels and overhaul schedules all have time resolutions of 1 hour. See chapter 3.3: *Data file content* on page 24 for a description of these data series.

It is assumed that there are no transfer constraints within the price areas.

The purpose of this project was to investigate the effect an increasing amount of on- and offshore wind power will have on the North-Western European power market. Therefore, it was decided to expand the existing market model in the following manner:

- Split Norway into three price areas: Norway North, Middle and South
- Add the Netherlands
- Add the United Kingdom
- Add corresponding offshore price areas for all areas neighbouring the North Sea, namely:
  - Norway North Offshore
  - Norway Middle Offshore
  - Norway South Offshore
  - Denmark West Offshore
  - Denmark East Offshore (not strictly neighbouring the North Sea, but added anyway)
  - Germany Offshore
  - Netherlands Offshore
  - UK Offshore

Scenarios are created, set in the years 2005, 2020 and 2030. In these scenarios, wind power capacities are increasing as time progresses in accordance with the scenarios created in the TradeWind project.[7] Realistically, loads and other types of generation can be expected to increase with time, but these have been held constant in all scenarios. Adding other variables like load growth and increase of other generation types would have made the concrete effects of wind power less apparent. Since the objective of this project was to study the concrete effects of wind power, these changes in loads and other generators have been omitted.

3.1 Price area descriptions

3.1.1 Denmark West

Power generation in Denmark West (DK-W) consists of conventional thermal, DCHP and wind power. Production capacities for thermal generation and DCHP are the same as in [2]. Wind power capacities are from [7].

Conventional thermal power:

Thermal generation in DK-W consists mainly of CHP generators which supply normal load situations. There are also some gas turbines which cover peak loads.

Type	Production capacity [MW]	Marginal costs MC = A + Bx [kr/MWh]
CHP	2230	170 + 0.100x
Peak power gas turbines	135	500 + 3x

Table 2: Conventional thermal generators in DK-W. [2 pp. 13 - 14, 28]

Wind power:

Onshore wind series for DK-W were already in the model. Offshore wind series were generated from re-analysis data at the coordinates lat 55.1, lon 8.1, with a utilization time of approximately 3600 hours.

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	2415	-
2020	3188	1367
2030	3721	2615

Table 3: Wind power capacities for DK-W. [7]

DCHP:

Power output from DCHP plants depends on the heat output of the plant, not on prices. Power output is therefore determined by historical series of hourly generation data from the period 2000 – 2006. DCHP is considered to operate independently of electricity prices, and is modelled without marginal costs. [2 pp. 25 - 27]

Load data:

The load series for DK-W were already included in the model, and were therefore not modified. [2 pp. 30 - 31]

3.1.2 Denmark East

Denmark East (DK-E) has the same types of power generation as DK-W: Conventional thermal, DCHP and wind power.

Conventional thermal power:

Like DK-W, thermal generation in DK-E consists mostly of CHP plants and some gas turbines which cover peak loads.

Type	Production capacity [MW]	Marginal costs MC = A + Bx [kr/MWh]
CHP	2776.3	170 + 0.0810x
Gas turbines	135	500 + 3x

Table 4: Thermal power generators in DK-E [2 pp. 13 - 14, 28]

Wind power:

Like DK-W, onshore wind series were already included in the model. Offshore wind series were generated at the coordinates lat. 54.6, lon. 12.4, with a utilization time of about 3200 hours.

	Installed capacity [MW]	
Year	Onshore	Offshore
2005	715	-
2020	899	385
2030	989	695

Table 5: Installed wind power in DK-E in 2005, 2020 and 2030. [7]

Load data:

Like DK-W, load data for DK-E were already included in the model. [2 pp. 30 - 31]

3.1.3 Norway North

Power generation in Norway North (NO-N) consists almost entirely of hydro power, but it is expected that the share of wind power will increase considerably towards 2030.

Hydro power:

NO-N has an installed production capacity of 4140.5 MW, with a total reservoir capacity of 19236.4 GWh. [8] NO-N has approximately 14% of Norway's total hydro power inflow. In the original model, Norway was modelled as one area. NO-N's inflow has therefore been calculated by multiplying the original Norwegian inflow series by a factor of 0.14. [2 p. 21]

Wind power:

Onshore wind series were generated at lat. 68.38, lon. 14.29, with a utilization time of ca. 3000 hours. Offshore wind series were generated at lat. 66.0, lon. 8.5. Offshore wind series along the Norwegian coast can be expected to have utilization times roughly between 3500 – 4000 hours. [4 p. 17] The offshore wind series were therefore scaled up to approximately 3700 hours.

Wind power in NO-N in 2005 is from the TradeWind project. [7]

Onshore installed wind power in Norway in 2020 and 2030 has been calculated from the NVE (Norwegian Water Resources and Energy Directorate) report "*Mulighetsstudie for landbasert vindkraft 2015 og*

2025” (Eng. translation: “*Feasibility study of land based wind power 2015 and 2025*”). [9]

Installed offshore wind power in Norway in 2020 and 2030 has been estimated by adding together all pre-notified offshore wind projects reported to NVE. These projects are published on the NVE web site. [10] See *Appendix 2: Calculation of Norwegian wind power in 2020 and* 2030 on page 55 for a detailed calculation of the Norwegian wind power capacities.

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	49	-
2020	1150	483
2030	2233	1450

Table 6: Installed wind power in NO-N in 2005, 2020 and 2030.

Load data:

Since Norway was modelled as one area in the original model, load data for Norway originally consisted of one data set representative of the entire country. [2 pp. 30 - 31] NO-N is responsible for ca. 13% of the energy consumption of Norway, according to NVE’s Energy Folder for 2005. [8 p. 9] By scaling the original Norwegian load series by this percentage, an approximated load series is found. The shape of the resulting load profiles will be identical, only magnitudes will differ. This method will therefore not completely reflect any seasonal load differences between the three Norwegian areas, but it is judged to be sufficient for the purposes of these simulations.

3.1.4 Norway Middle

Presently, Norway Middle (NO-M) has the largest share of wind power in Norway. However, hydro power is the dominating form of generation in the region. It is expected that there will be a large expansion of wind power in the future, both on- and offshore.

Hydro power:

NO-M has a total generating capacity of 3026.2 MW and a total reservoir volume of 8110 GWh. NO-M has 12% of Norway’s total inflow. Regional inflow has been calculated using the same method as in NO-N. [8]

Wind power:

Onshore wind series for NO-M were generated at lat. 63.25, lon. 7.56, scaled to a utilization time of roughly 3000 hours. Offshore series were generated at lat. 62.1, lon. 4.3, scaled to approximately 3700 hours, based on the same assumptions as in NO-N.

Installed wind power capacities are found by the same method as described for NO-N.

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	216	-
2020	1667	866
2030	2717	2598

Table 7: Installed wind power in NO-M in 2005, 2020 and 2030.

Load data:

NO-M has approx. 15% of the total Norwegian energy consumption. [8 p. 9] Using the same method as for NO-N, a load series is developed.

3.1.5 Norway South

Norway South (NO-S) contains the majority of the Norwegian hydro power generation. There is at present very little wind power in the region.

Hydro power:

Installed hydro power capacity in NO-S is 20100.6 MW, with a reservoir capacity of 57090.4 GWh. This region has 74% of Norway's total inflow. Inflow time series are calculated in the same manner as in NO-N and NO-M. [8]

Wind power:

Onshore wind series for NO-S are generated at lat. 58.4, lon. 5.32, and scaled to a utilization time of ca. 3000 hours. The offshore series are generated at lat. 58.1, lon. 5.5 and scaled to a utilization time of about 3700 hours, like the offshore series of NO-N and NO-M.

Installed on- and offshore wind power capacities for 2005, 2020 and 2030 are found by the same methods as described in NO-N.

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	9	-
2020	1883	766
2030	2200	2298

Table 8: Installed wind power in NO-S in 2005, 2020 and 2030.

Load data:

NO-S is responsible for roughly 72% of the total Norwegian energy consumption. [8 p. 9] Using the same method as for NO-N and NO-M, a load series is developed.

3.1.6 Sweden/Finland

The price area Sweden/Finland (SE/F) was already included in the model. Wind power capacities have been modified to match the TradeWind scenarios. [7]

Power generation in this region consists of conventional thermal, hydro, wind and nuclear power.

Conventional thermal power:

Thermal generation in SE/F is divided into two segments, 10435 MW of low cost CHP and 5584 MW of high cost generation used to cover peak power loads. [2 pp. 14 - 15]

Type	Production capacity [MW]	Marginal costs MC = A + B*x* [kr/MWh]
CHP	10435	160 + 0.0048*x*
Peaking power	5584	210 + 0.4191*x*

Table 9: Thermal power generators and marginal costs in SE/F. [2 pp. 14 - 15, 28]

Hydro power:

SE/F is modelled with 19167 MW of hydro power generation, and a maximum reservoir capacity of 39288 GWh. Inflow series were already included and therefore not modified in any way. [2 pp. 21, 28]

Wind power:

according to the TradeWind project, both Sweden and Finland have plans for offshore wind farms in the Baltic Sea. [7] To simplify, all wind power in SE/F has been modelled as onshore on the assumption that offshore and onshore wind in the region have fairly similar characteristics. Therefore, only onshore wind series were generated for this region, at lat. 56.5, lon. 14.0 with a utilization time of approximately 2300 hours.

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	575	-
2020	13000	-
2030	23000	-

Table 10: Installed wind power in SE/F in 2005, 2020 and 2030. [7]

Nuclear power:

SE/F is modelled with 11632 MW of nuclear power and a marginal cost of 80 kr/MWh. [2 pp. 27 - 28]

Load data:

Load data series for SE/F were already included in the model. [2 pp. 30 - 31]

3.1.7 Germany

Germany (DE) has conventional thermal, nuclear, hydro and wind power generation. DE was already included in the model. Only wind power capacities have been modified to use values from TradeWind.

Conventional thermal power:

Description	Production capacity [MW]	Marginal costs MC = A + B*x* [kr/MWh]
	41500	130 + 0.0010*x*
	4500	170 + 0.0464*x*
	10000	378
	11750	378.4 + 0.0052*x*
	3250	440 + 0.1292

Table 11: Thermal power generators and marginal costs in DE. [2 pp. 15, 28]

Hydro power:

Hydro power is represented by a thermal generator with a capacity of 3185 MW and a marginal cost of 24 kr/MWh. It is modelled in this way because of its operation conditions and the lack reservoir and inflow information. [2 pp. 15, 28]

Wind power:

The model already contained onshore wind series for Germany. [2 pp. 23 - 24] Offshore wind series were generated at lat. 54.4, lon. 6.2, with a utilization time of 3600 hours.

Year	Installed capacity [MW]	
	Onshore	Offshore
2005	18428	-
2020	32029	24611
2030	33630	29957

Table 12: Installed wind power in DE in 2005, 2020 and 2030. [7]

Nuclear power:

Germany has 20700 MW of nuclear power, with a marginal cost of 80 kr/MWh. [2 pp. 27 - 28]

Load data:

Load data series for DE were already included in the model. [2 pp. 30 - 31]

3.1.8 UCTE/Others

This price area represents the rest of the European power market. Generation capacity in this area is modelled as conventional thermal as a rough approximation. [2 pp. 15 - 16]

This area was originally modelled without any wind power, but this has been added for these simulations.

Conventional thermal power:

Description	Production capacity [MW]	Marginal costs MC = A + B*x* [kr/MWh]
	184000	80 + 0.0004*x*
	76000	160 + 0.0021*x*
	70000	320 + 0.0096*x*

Table 13: Thermal power generators and marginal costs in UCTE. [2 pp. 28 - 29]

Wind power:

TradeWind wind power capacities from the following countries has been added to this area: Austria, Belgium, Bulgaria, Croatia, the Czech Republic, France, Greece, Hungary, Italy, Luxembourg, Poland, Portugal, Ireland and Northern Ireland, Romania, Serbia, Slovakia, Spain and Switzerland. [7] For the sake of simplicity, all of this wind power has been modelled as onshore. This adds up to the following wind power scenarios for UCTE:

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	16920	-
2020	137481	-
2030	195747	-

Table 14: Installed wind power in UCTE in 2005, 2020 and 2030. [7]

Wind series were generated at lat. 45.2, lon. 0.24 with a utilization time of ca. 2500 hours.

Load data:

Load data for UCTE was already included in the model. [2 pp. 30 - 31]

3.1.9 The Netherlands

Power generation in the Netherlands consists of conventional thermal, wind and nuclear power. There is also a very small quantity (37 MW) of run-of-river hydro power, but this has been disregarded in these simulations. [11]

Conventional thermal power:

In 2005 the Netherlands contained 19457 MW of thermal power generation capacity. [11] The report "*Position of large power producers in electricity markets of North Western Europe*" by M.J.J. Scheepers, A.J. Wals and F.A.M. Rijkers, contains a SRMC curve for power generation. [12 p. 30]

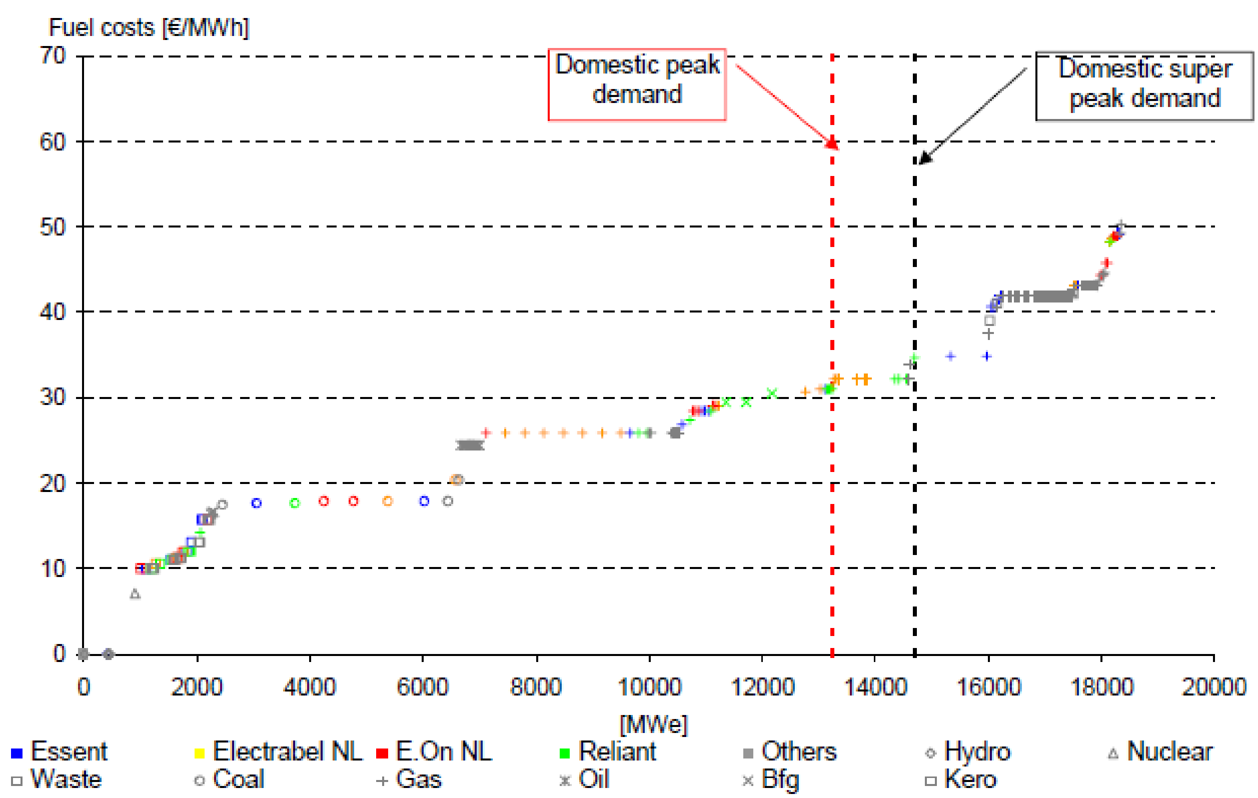


Figure 2: SRMC curve for the Netherlands in 2001. [12 p. 30] Nuclear generation is assumed to have a constant marginal cost of 7 [€/MWh], while thermal generation has an approximated linear cost curve of 10 + 0.0024*x* [€/MWh]

The shape of the SRMC curve makes it possible to approximate the entire curve with one linear marginal cost function. This gives the following marginal cost function:

$$MC = A + B \cdot x$$

$$MC \approx 10 + 0.0024 \cdot x\left[{}^{€}\!/\!{}_{\mathrm{MWh}}\right] \approx 134.2 + 0.0322 \cdot x\left[{}^{\mathrm{kr}}\!/\!{}_{\mathrm{MWh}}\right]$$

Using these generator costs resulted in too high imports to the Netherlands compared to historical data.

By scaling the thermal generation costs by a factor of 0.63, transfers in to and out of the Netherlands become closer to real data from 2005. This adjustment was judged to be good enough for the purposes of these simulations. This resulted in the following marginal costs:

$$MC \approx 84.5 + 0.0203 \cdot x \left[{}^{\mathrm{kr}}\!/\!_{\mathrm{MWh}} \right]$$

Wind power:

Onshore wind series were created at lat. 52.4, lon. 4.7 with a utilization time of approximately 2350 hours. Offshore series were generated at lat. 52.4, lon. 4.7 with a utilization time of 3300 hours.

The following wind power capacities have been used, according to the TradeWind project:

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	1224	-
2020	4100	6000
2030	4200	6000

Table 15: Installed wind power in NL in 2005, 2020 and 2030. [7]

Nuclear power:

According to the UCTE website, there is 449 MW of installed nuclear power in the Netherlands.

From Figure 2, nuclear gen. costs approximated to be:

$$MC \approx 7 \left[{}^{€}\!/\!_{\mathrm{MWh}} \right] \approx 93.9 \left[{}^{\mathrm{kr}}\!/\!_{\mathrm{MWh}} \right]$$ [12 p. 30]

Load data:

It is assumed that the Dutch load profile follows roughly the same shape as the German load profile. According to UCTE, in 2005 the total German consumption was 556371 GWh and the Dutch consumption was 114658 GWh. [11]

Dutch load data series are obtained by scaling the German load series by the following factor:

$$\frac{114658}{556371} = 0.2061$$

3.1.10 The United Kingdom

The report "*Statistics and prospects for the European electricity sector (1980 - 1990, 2000 - 2030)*" contains a detailed account of power generation in the UK in 2004. [13] Power production in the UK consists mainly of conventional thermal, hydro, wind and nuclear power. The UK has got ambitious plans for future wind power expansion.

Conventional thermal power:

The UK contains approximately 61200 MW of conventional thermal generation. This encompasses sources like for example coal, gas and other types of power plants.

Spot market prices from the UK power market in 2005 downloaded from elexon.co.uk. [14] Converting prices from £ to DKK and sorting them from lowest to highest gives the following price curve. This curve is assumed to be representative for the entire demand in the UK.

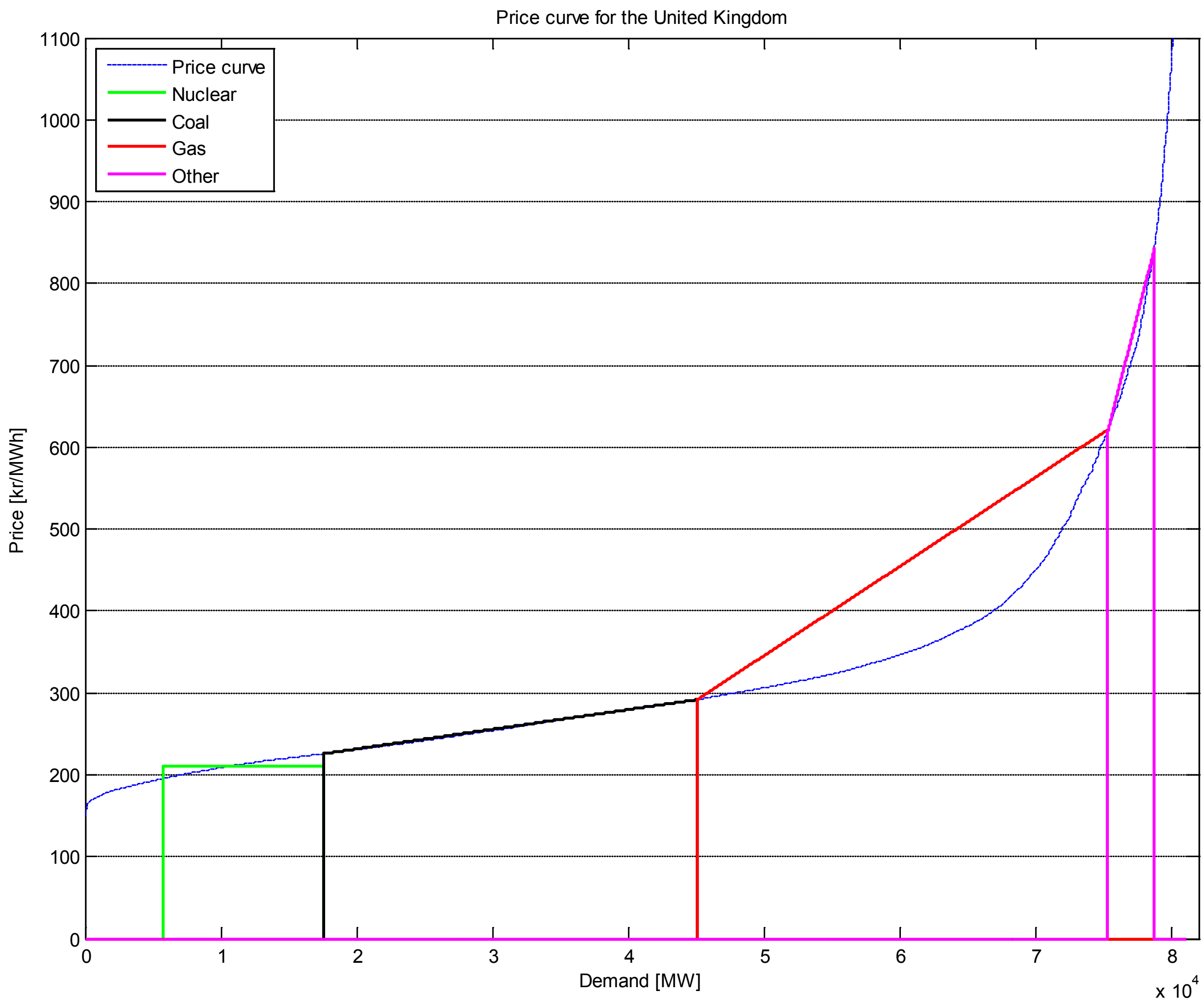


Figure 3: UK price curve with fitted linear marginal cost curves for the different generation types.

Assuming that hydro, wind and nuclear covers the lowest price segment, thermal power starts at ca. 17560 MW. To allow for accuracy, thermal generation is divided into three segments: Coal (ca. 27570 MW), Gas (ca. 30200 MW) and Other (ca. 3430 MW).[13 p. 105]

Coal is assumed to be cheapest generation type and Other to be the most expensive. This gives the following marginal cost approximations:

Type	Production capacity [MW]	Marginal costs MC = A + Bx [kr/MWh]
Coal	27570	225.7 + 0.0024*x*
Gas	30200	291.9 + 0.0109*x*
Other	3430	619.6 + 0.0650*x*

Table 16: Thermal generating capacities and marginal costs in the UK.

See *Appendix 3: Detailed marginal cost calculations for the* UK, page 58 for detailed calculations.

Hydro power:

The UK has roughly 4250 MW of hydro power generation. [13 p. 105] Information about reservoir capacities and inflow searched for unsuccessfully. Therefore, maximum reservoir level is assumed to be 10000 GWh and inflow is the same as for NO-N.

Wind power:

Onshore wind series for the UK were generated at lat. 51.3, lon. 0.0 with a utilization time of about 2500 hours. Offshore series were created at lat. 53.4, lon. 0.36 with a utilization time of ca. 3700 hours.

The TradeWind project states that the UK had 1246 MW of onshore and 214 MW of offshore wind power in 2005. However, as most of the offshore wind farms so far have been installed in very shallow waters close to the coast and therefore mostly bear the same characteristics as onshore wind farms, they have been pooled together with the onshore farms.

Given the UK's ambitious wind power plans, this area has been set to reach its TradeWind 2030 scenario by 2020. This has also been factored into the model.

	Installed capacity [MW]	
Year	**Onshore**	**Offshore**
2005	1460	-
2020	18267	33000
2030	19363	33000

Table 17: Installed wind power in the UK in 2005, 2020 and 2030. [7]

Nuclear power:

The UK has 11852 MW of nuclear power. Assuming that nuclear power covers the load segment in-between hydro/wind and conventional thermal, we get the following marginal cost approximation:

$$MC_N = A_N$$

$$\text{Start:} \quad x = 5710 \text{ MW}$$
$$y = 195.2$$
$$\text{Available prod. cap.} \approx 11850 MW$$
$$\text{Stop:} \quad x = 5710 + 11852 = 17560 MW$$
$$y = 225.7$$
$$A_N = \frac{195.2 + 225.7}{2} = 210.45$$

Load data:

The UK load profile is also assumed to be similar to the German load profile. Therefore, the same method is used to obtain load data for the UK as for the Netherlands. The total energy consumption in the UK in 2004 was 382.5 TWh. [13 p. 66]

$$\frac{382.5[TWh]}{556371[GWh]} \approx 0.6875$$

3.1.11 The offshore areas

There are 8 offshore areas in the model. These are not included in the 2005 scenario since there was no offshore wind generation to speak of at that time. Each offshore area “belongs” to a corresponding on-shore area. They are mainly corresponding with respect to geographical placement.

Offshore areas have no loads and can therefore export its entire production. Offshore installations such as oil rigs may one day be powered by offshore wind power, but this possibility has not been taken into consideration in this project.

3.1.12 Summary of price areas

Area	Generation type	Minimum capacity [MW]	Maximum capacity [MW]	Marginal costs MC = A + Bx [kr/MWh]	Hydro reservoir [GWh]	Comment
1. DK-W	3. Wind	0	*2005*: 2415 *2020*: 3188 *2030*: 3721			
	4. DCHP					
	1. Conv. thermal	0	2230	170 + 0.100x		
	1. Conv. thermal	0	135	500 + 3x		
2. DK-E	3. Wind	0	*2005*: 715 *2020*: 899 *2030*: 989			
	4. DCHP					
	1. Conv. thermal	0	2776.3	170 + 0.081x		
	1. Conv. thermal	0	135	500 + 3x		
3. NO-N	2. Hydro	0	4140.5		19236,4	
	3. Wind	0	*2005*: 49 *2020*: 1150 *2030*: 2233			
4. NO-M	2. Hydro	0	3026.2		8110	
	3. Wind	0	*2005*: 216 *2020*: 1667 *2030*: 2717			
5. NO-S	2. Hydro	0	20100.6		57090,4	
	3. Wind	0	*2005*: 9 *2020*: 1883 *2030*: 2200			
6. SE/F	2. Hydro	0	19167		39288	
	5. Nuclear	5816	11632	80		
	1. Conv. thermal	0	10435	160 + 0.0048x		
	1. Conv. thermal	0	5584	210 + 0.4191x		
	3. Wind	0	*2005*: 575 *2020*: 13000 *2030*: 23000			
7. DE	3. Wind	0	*2005*: 18428 *2020*: 32029 *2030*: 33630			
	5. Nuclear	10350	20700	80		
	6. Other	0	3185	24		Representing DE hydro power
	1. Conv. thermal	0	41500	130 + 0.0010x		
	1. Conv. thermal	0	4500	170 + 0.0464x		
	1. Conv. thermal	0	10000	378		
	1. Conv. thermal	0	11750	378.4 + 0.0052x		
	1. Conv. thermal	0	3250	440 + 0.1292		
8. UCTE	1. Conv. thermal	0	184000	80 + 0.0004x		
	1. Conv. thermal	0	76000	160 + 0.0021x		
	1. Conv. thermal	0	70000	320 + 0.0096x		
	3. Wind	0	*2005*: 16920 *2020*: 137481 *2030*: 195747			

Continued from above…						
Area	**Generation type**	**Minimum capacity [MW]**	**Maximum capacity [MW]**	**Marginal costs MC = A + Bx [kr/MWh]**	**Hydro reservoir [GWh]**	**Comment**
9. NL	1. Conv. thermal	0	19457	84.5 + 0.0203*x*		
	5. Nuclear	224.5	449	93.9		
	3. Wind	0	*2005*: 1224 *2020*: 4100 *2030*: 4200			
10. UK	1. Conv. thermal	0	27570	225.7 + 0.0024*x*		
	1. Conv. thermal	0	30200	291.9 + 0.0109*x*		
	1. Conv. thermal	0	3430	619.6 + 0.0650*x*		
	5. Nuclear	5926	11852	210.45		
	3. Wind	0	*2005*: 1460 *2020*: 18267 *2030*: 19363			
	2. Hydro	0	4250		10000	Assumed reservoir value and inflow data
11. NO-N Offshore	3. Wind	0	*2005*: - *2020*: 483 *2030*: 1450			
12.. NO-M Offshore	3. Wind	0	*2005*: - *2020*: 866 *2030*: 2598			
13. NO-S Offshore	3. Wind	0	*2005*: - *2020*: 766 *2030*: 2298			
14. DK-W Offshore	3. Wind	0	*2005*: - *2020*: 1367 *2030*: 2615			
15. DK-E Offshore	3. Wind	0	*2005*: - *2020*: 385 *2030*: 695			
16. DE Off-shore	3. Wind	0	*2005*: - *2020*: 24611 *2030*: 29957			
17. NL Off-shore	3. Wind	0	*2005*: - *2020*: 6000 *2030*: 6000			
18. UK Off-shore	3. Wind	0	*2005*: - *2020*: 33000 *2030*: 33000			

Table 18: Installed generation capacity in each price area. Installed wind power capacities are stated in the case files. The scenario for 2005 contains areas 1 – 10. The scenarios for 2020 and 2030 contain all 18 areas.

3.2 Transmission grid

Each line in the transmission grid is simply described by its maximum transfer capacity. Other line data such as voltages, currents, phase angles and reactive powers are disregarded in this model. Transmission capacities are described in a $n \times n$ transmission matrix, where *n* is the number of price areas in the model. [2 p. 31] The 2005 scenario contains 10 areas, while the 2020 and 2030 scenarios have 18 areas.

3.2.1 Transfer capacities in the 2005 scenario

Most of the transfer capacities for 2005 were found at the website of the organization European Transmission System Operators (ETSO), www.etso-net.org. [15] In this overview, Norway is represented as one area, so the Norwegian transfer capacities were found in the TradeWind report "*D3.2 Grid modelling and power system data*". [16 s. 81]

To, *j* / From, *i*	DK-W	DK-E	NO-N	NO-M	NO-S	SE/F	DE	UCTE	NL	UK
DK-W	–				950	490	1200			
DK-E		–				1700	550			
NO-N			–	600		600				
NO-M			600	–	300	600				
NO-S	1000			300	–	2050				
SE/F	460	1300	700	500	1850	–	600	600		
DE	800	550				600	–	12500 1)	3800	
UCTE						500	12050 2)	–	2400	2000
NL							3000	2350	–	
UK								2000		–

Table 19: Cells marked in blue are from [15], cells marked in red are taken from [16 s. 81] Transfer capacities in MW, from area in row *i* to area in column *j*. 1) Summed together from transfers from DE to FR, CH, AT, PL and CZ. 2) Sum of trans. to DE from FR, CH, AT, PL and CZ.

3.2.2 Transfer capacities in the 2020 scenarios

In the scenarios for 2020 and 2030, the offshore areas were added. This increased transfer constraint matrix dimensions from 10x10 to 18x18. Because of their size, the matrices for 2020 and 2030 have been placed in *Appendix 4: Transmission* matrices on page 59. The following expansions were made to the 2020 transmission grid:

- The NorNed HVDC connection between Norway and the Netherlands was added and expanded from 700 MW [17] to an assumed future capacity of 1400 MW.
- The Storebælt HVDC connection between Denmark West and East was added with a capacity of 600 MW. [18]

- Added increased transfer capacity between Norway South and Middle, because of the Ørskog – Fardal project. An assumed expansion of 1000 MW was used, resulting in a total capacity of 1300 MW. [19]
- Assumed an increased transfer capacity between Norway North and Middle. An assumed expansion of 1000 MW was used, resulting in a total capacity of 1600 MW.
- Added the NorGer connection between Norway South and Germany. An assumed capacity of 1400 MW was used.
- Transfer constraints between NO-S and DK-W were increased by an assumed value of 1000 MW to a total capacity of 1950 MW.
- The remainder of the transfer capacities were updated using ETSO numbers from December 2008. [17]
- Grid connections between corresponding off- and onshore areas are dimensioned so that they are able to transport their maximum power output to land. For example, an offshore area with an installed wind power capacity of 4000 MW will have a transfer line capacity of at least 4000 MW to its corresponding onshore area.

The 2020 grid was made in two versions, one with and one without an offshore grid.

3.2.3 Transfer capacities in the 2030 scenarios

Transfer capacities in the 2030 scenario are identical to the 2020 transfer capacities, with the following exceptions:

- Offshore-to-onshore connections were altered according to the increase in installed offshore wind power.
- A 2000 MW subsea cable between Norway South and the UK was added

An overview can be seen in *Appendix 4: Transmission* matrices on page 60.

When testing the 2030 scenario, it was observed that energy prices in the Norwegian price areas dropped significantly. Area prices in NO-N and NO-M were between 30 and 40 [kr/MWh]. It was concluded that this was caused by large quantities of superfluous wind and hydro power. Therefore, an alternative 2030 grid was constructed, containing the following changes:

- The transfer constraint between NO-N and NO-M was increased to 4600 MW.
- The transfer constraint between NO-N and SE/F was increased to 900/800 MW.
- The transfer constraint between NO-M and NO-S was increased to 4300 MW.
- The transfer constraint between NO-M and SE/F was increased to 700/800 MW.
- The transfer constraint between NO-S and SE/F was increased to 2850/3050 MW.
- The transfer constraint between NO-M and DE was increased to 2000 MW.
- The transfer constraint between NO-M and NL was increased to 2000 MW.

The upgraded 2030 grid will be referred to as 2030 Mark 2 from here on. This grid was also made in two versions, with and without an offshore grid. An overview can be seen in *Appendix 4: Transmission* matrices on page 61.

3.2.4 The offshore grid

The 2020 and 2030 scenarios have been simulated with two alternative grid configurations: one where the offshore areas are connected only to their respective onshore areas and one where the offshore areas are also interconnected in an offshore grid.

To, *i* / **From, *i***	**NO-N Off.**	**NO-M Off.**	**NO-S Off.**	**DK-W Off.**	**DK-E Off.**	**DE Off.**	**NL Off.**	**UK Off.**
NO-N Off.	–	1500						
NO-M Off.	1500	–	1500					
NO-S Off.		1500	–	1500		1500	1500	1500
DK-W Off.			1500	–		1500	1500	1500
DK-E Off.					–			
DE Off.			1500	1500		–	1500	1500
NL Off.			1500	1500		1500	–	1500
UK Off.			1500	1500		1500	1500	–

Table 20: The offshore grid interconnections used in the 2020 and 2030 scenarios. All transmission capacities are assumed values.

These grid connections between the offshore areas will henceforth be referred to as the offshore grid. The offshore grid also includes the connections to onshore areas. However, the connections to onshore will be present in all scenarios featuring offshore wind farms. The entire offshore grid is illustrated in Figure 4.

This grid configuration will provide a high level of flexibility regarding power transmissions in the North Sea. The number of crisscrossing lines is however not very realistic, and an actual offshore grid would likely have a more rationalized configuration.

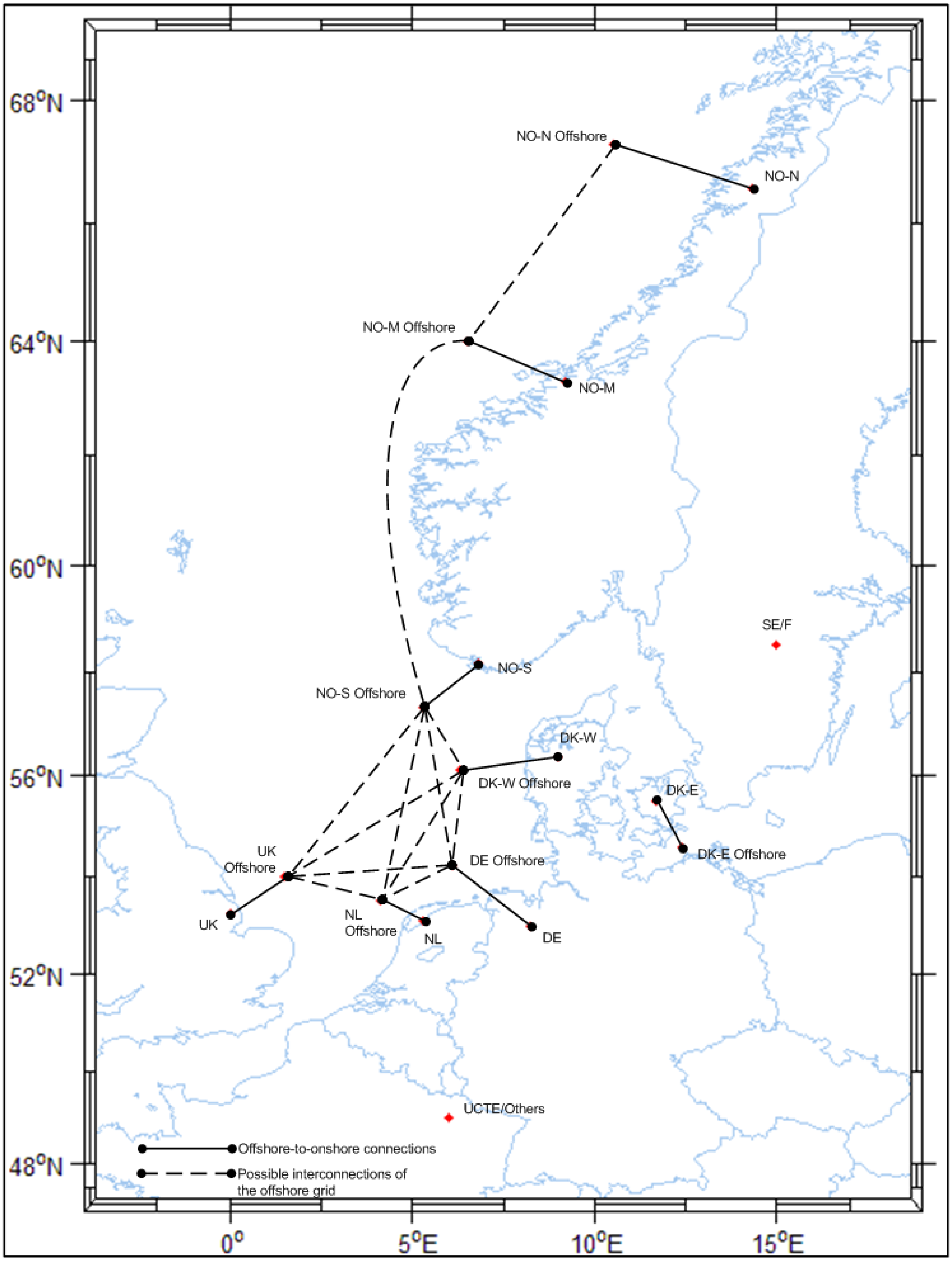


Figure 4: Illustration of the offshore grid and its onshore connections as simulated in the scenarios.

3.3 Data file content

All time series necessary for the simulations are gathered in a data file. The contents of the data files (market2005Data.mat and market2020Data.mat) are common for all scenarios (2005, 2020, 2030). The following data series can be found in these files:

Data series name	Function	Dimensions
load	Determines the hourly power load.	7 years (yr. 2000 – 2006 for most areas) of hourly load data for each price area in the model.
inflow	Determines inflow to hydro reservoirs each hour.	21 years of hourly inflow data of each price area containing hydro power generation.
rmedian	Median reservoir levels used to calculate water values for hydro power generators.	2 years of hourly median reservoir levels.
wind	Determines maximum possible wind power output every hour.	7 years (yr. 2000 – 2006) of hourly wind data for each wind farm in the model.
overhaul	Determines the reduction in maximum production capacity due to maintenance.	1 year of hourly overhaul data for thermal and nuclear generators.
outagelist	Describes generator outages.	Not used.
dchp	Determines power output for the DCHP generators.	7 years (yr. 2000 – 2006) of hourly production data per area for District Combined Heat and Power (DCHP) in Denmark West and Denmark East.
serieslength	The number of samples in each time series. 8760 samples for a year with a sample rate of 1 per hour.	

Table 21: Description of the contents of the data files of market2005Data.mat and market2020Data.mat

4 Simulation setup

7 scenarios were simulated, their order of presentation represents increasing installed wind power and grid capacities:

1. The 2005 scenario
2. The 2020 scenario without an offshore grid
3. The 2020 scenario with an offshore grid
4. The 2030 scenario without an offshore grid
5. The 2030 scenario with an offshore grid
6. The 2030 Mark 2 scenario without an offshore grid
7. The 2030 Mark 2 scenario with an offshore grid

All scenarios have been simulated for 21 runs (i.e. years).

There are 21 years of inflow data for each area with hydro inflow. All scenarios have been set to use the inflow series in consecutive order. This means that for the first run inflow series 1 are used, the second run use series 2 and so on. In this way all inflow series are used once.

Load, wind and DCHP each have 7 data series per area from the same time period (yrs. 2000 – 2006). Power consumption, wind power and DHCP are all correlated to temperature and therefore to each other. [2 pp. 26 - 27] All scenarios have been set to use these series in consecutive order (1, 2, 3 … 7) and then to repeat the sequence. Since the simulations have 21 runs, this sequence is repeated 3 times. This means that in a run when load series from year 2001 are used, wind series and DHCP series from the same year are also used.

The model also contains options to adjust overall transfer capacities and thermal generation costs underway in the simulations. These options have not been used.

The output of each simulation is 21 years of hourly simulation data. The most important of these are:

- Production data for each generator in MW
- Transmission data for each transmission line in MW
- Area prices for each area
- Reservoir levels for each hydro power reservoir
- Load data for each area

Individual years are considered to be possible outcomes of the scenario in question, given different conditions in load, wind, hydro inflow etc. The 21 years are therefore averaged to one mean year before further evaluating the simulation data. A MATLAB script was developed to do this and then to calculate the following:

- Average area prices [kr/MWh]
- Yearly energy costs [kr]
- Total yearly energy production sorted by generation type [MWh]
- Total yearly energy production per area [MWh]
- Total yearly energy consumption per area [MWh]
- Average system price [kr]
- Correlation coefficients between wind farms
- Imports and exports for each area [MWh]
- Total yearly line transfers [MWh]
- Mean line loading [MW]
- Yearly costs of the offshore grid including onshore connections [kr]
- Lost hydro power inflow due to reservoir overflow [MWh and %]
- Lost wind power due to production curtailment [MWh and %]

The simulation results are presented and discussed in chapter 5: *Results and discussion*.

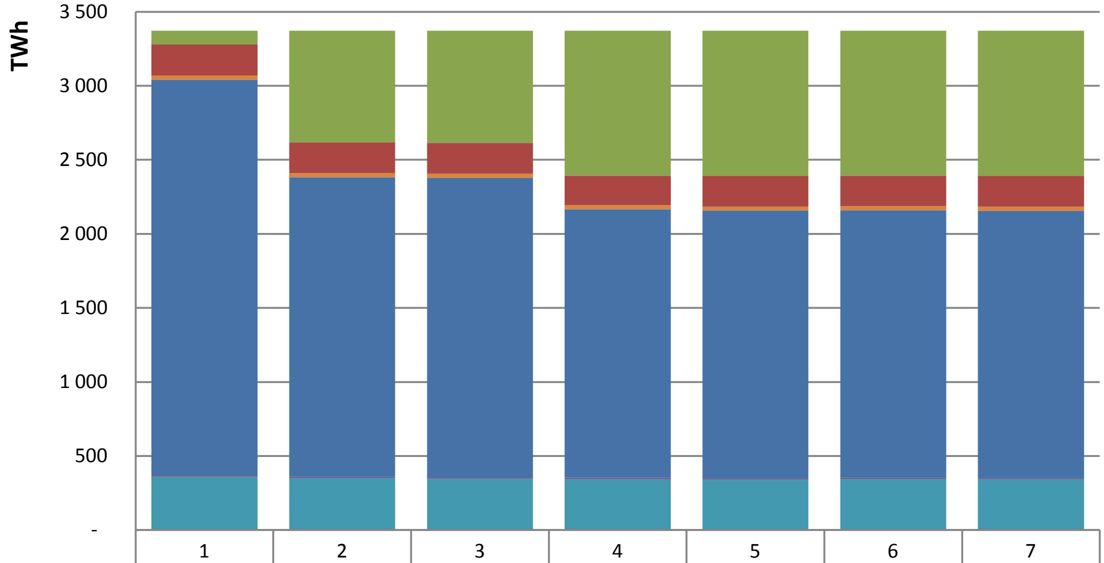
5 Results and discussion

The different scenarios will in the following be referred to as scenario 1, scenario 2, etc. The scenarios have been numbered in the following order, as mentioned in chapter 4:

1. The 2005 scenario
2. The 2020 scenario without an offshore grid
3. The 2020 scenario with an offshore grid
4. The 2030 scenario without an offshore grid
5. The 2030 scenario with an offshore grid
6. The 2030 Mark 2 scenario without an offshore grid
7. The 2030 Mark 2 scenario with an offshore grid

Scenarios set in the same year have the same amount of installed wind power. Each scenario also has a unique transmission grid setup as explained in chapter 3.2: *Transmission grid* on page 22.

5.1 Yearly energy production



	1	2	3	4	5	6	7
Wind	91 853 267	753 448 082	757 575 292	978 223 719	981 973 536	979 247 052	982 111 638
Hydro	210 337 682	208 346 388	209 217 699	199 278 596	205 785 190	206 028 869	207 479 418
Other	27 897 108	27 886 744	27 882 120	27 754 564	27 695 112	27 746 328	27 705 816
Conventional Thermal	2 673 087 964	2 023 587 765	2 022 407 582	1 814 730 314	1 806 696 899	1 806 269 225	1 804 219 301
DHCP	8 657 220	8 657 219	8 657 220	8 657 219	8 657 220	8 657 219	8 657 220
Nuclear	359 570 297	349 842 376	346 030 241	343 121 605	340 960 622	343 821 914	341 598 352

Figure 5: Yearly energy production in each scenario sorted by generator type. The numbers in the table are given in MWh.

Scenario	1	2	3	4	5	6	7
Sum	3 371 403 538	3 371 768 574	3 371 770 154	3 371 766 017	3 371 768 578	3 371 770 606	3 371 771 744

Table 22: Total energy production in MWh for each scenario.

The total energy production varies relatively little between scenarios, considering that a large amount of cheap generating capacity is introduced to the system in scenarios 2 – 7. Since power consumption in the model is determined by time series, total energy consumption – and therefore also total energy production – will appear to be largely unaffected by prices. In reality, consumers would probably have reacted to the lowered energy prices by increasing consumption.

Figure 5 and Figure 6 show that wind power is able to supplant a large share of energy originally produced by conventional thermal generators. In the 2005 scenario, conventional thermal generators are responsible for roughly 79% of the total energy production, while wind power has a share of 3%. In the 2020 scenarios, (scenarios 2 and 3) conventional thermal generators constitute ca. 60% of the total yearly energy production and wind power's share has creased to about 22%. In the 2030 scenarios (scenarios 4 – 7) conv. thermal has a share of about 54%, while wind power has a share of ca. 29%.

The presence of an offshore grid does not have any dramatic effects on yearly energy production for the system as a whole. It is however worth noting that all scenarios with off-shore grids (scenarios 3, 5 and 7) have higher quantities of produced wind and hydro energy than their counterparts without offshore grids (scenarios 2, 4 and 6 respectively). It is therefore possible to conclude that the presence of an off-shore grid may contribute to slightly shift the power system in favour of renewable energy sources.

The generators with the highest marginal costs will be the first to be replaced. With the conditions given in the model, expensive thermal generators like gas turbines will be the first to be replaced by wind power, followed by progressively cheaper generators. Cheaper thermal generators like coal-fired plants will also be affected by wind power, but to a lesser degree. This is optimal with respect to energy prices, though not necessarily with respect to environmental concerns. This is because cheaper energy sources like coal are generally heavier polluters than expensive sources like gas turbines.

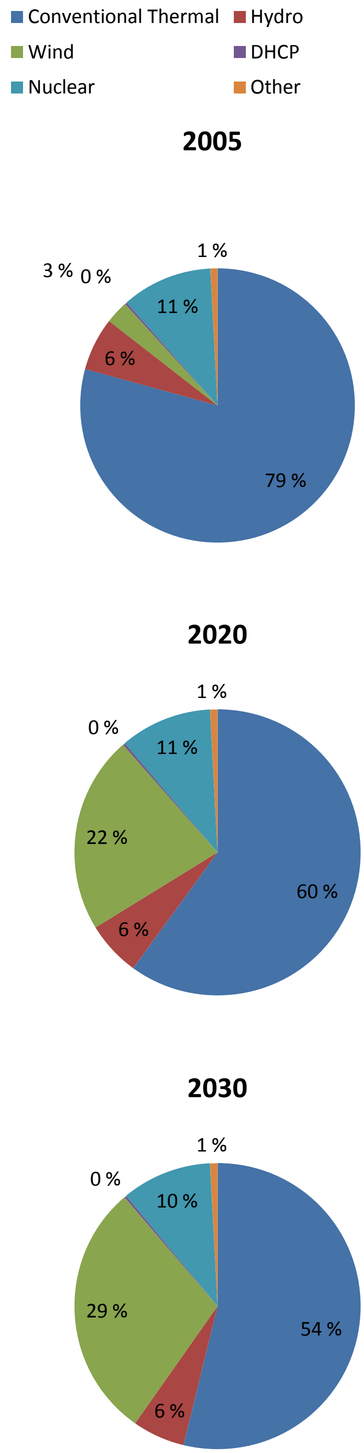


Figure 6: Percentage of yearly energy production by source.

Hydro and nuclear generators also experience a drop in total energy production. This drop in production is most likely due to production curtailment whenever winds are high. Hydro power in scenario 4 stands out among the others, with a significant drop in total production. This is caused by a large amount of available hydro and wind power in Norway, combined with insufficient transfer capabilities between and out of these areas.

Nuclear generation may pose a challenge in situations when wind power output is very high, since it is not possible to reduce power output from nuclear generators beyond a certain level. This will for the most part be a problem for areas with large shares of nuclear generation, like Sweden/Finland, Germany and the United Kingdom.

DHCP production is unaffected by the introduction of wind power and remains the same in all scenarios. This is because DHCP is modelled as independent of demand and electricity prices, as explained earlier.

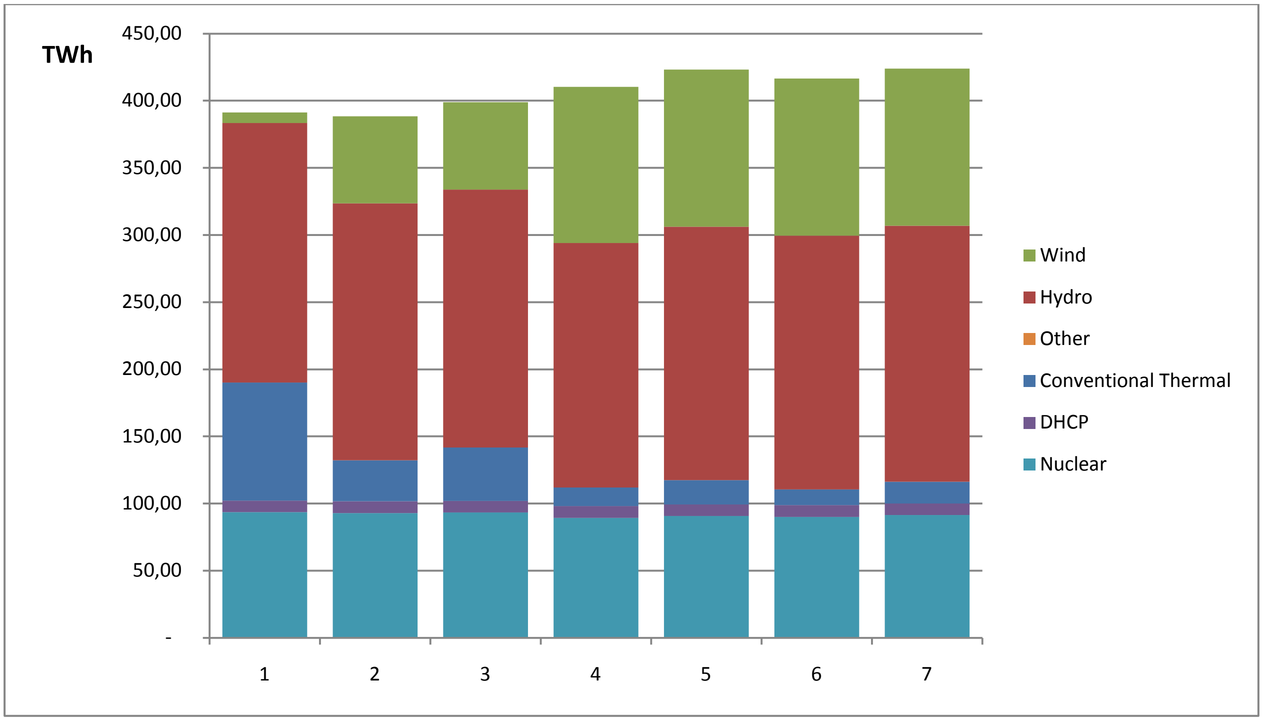


Figure 7: Yearly Nordel energy production in each scenario sorted by generator type.

A closer look at the Nordel areas (Denmark, Norway and Sweden/Finland) shows that the same general development takes place here. Conventional thermal generation is reduced from about 23% in scenario 1 to between ca. 10% in 2020 and to about 4% in 2030. The 2005 scenario is judged to be realistic in terms of production distribution between generators. [20 p. 9] The share of renewable energy changes in the manner shown by Figure 8.

Year	2005	2020	2030
Hydro	49%	48%	45%
Wind	2%	16%	28%
Sum renewables	51%	64%	73%

Figure 8: Share of renewable energy in the Nordel areas.

It is interesting to note that the offshore grid causes wind, hydro and also thermal generation to increase. Total generation increases for scenarios 3 – 7, presumably decreasing the need for importing energy from the continent and creating more opportunities for export.

5.2 System and area prices

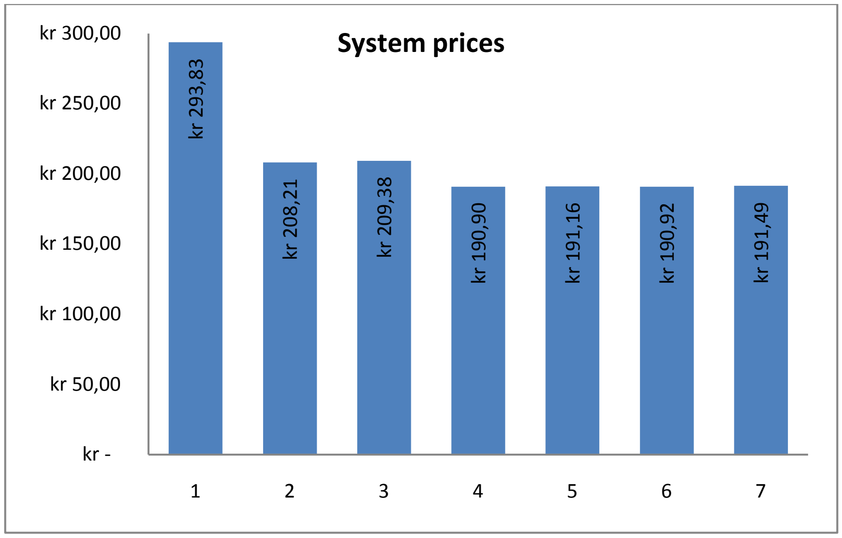


Figure 9: Average yearly system prices in each scenario.

It is evident from Figure 9 that the overall system price will be affected significantly by the introduction of large quantities of wind power. The largest difference can be seen when comparing scenario 1 (yr. 2005) to scenarios 2 and 3 (yr. 2020 without and with offshore grid). It is interesting to note that scenarios with offshore grids (scenarios 3, 5 and 7) have slightly higher system prices than their counterparts without offshore grids (scenarios 2, 4 and 6 respectively).

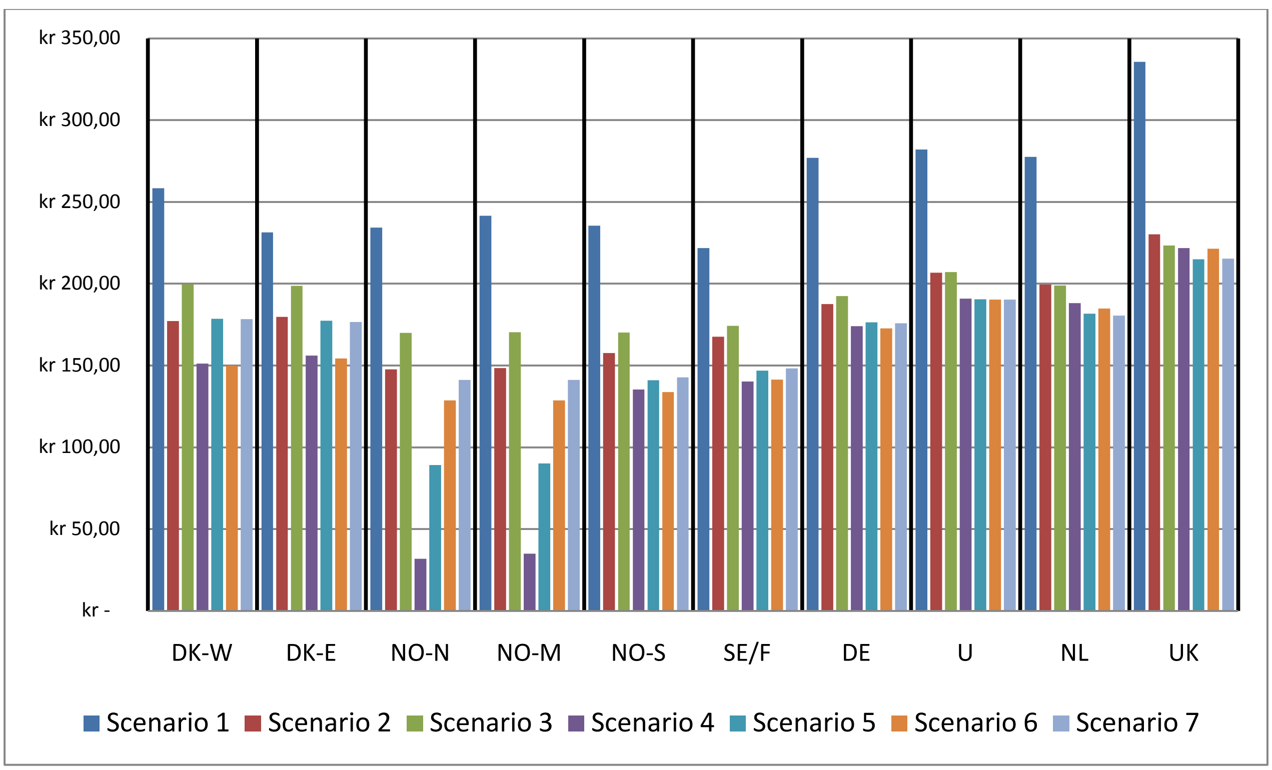


Figure 10: Area prices for each scenario, sorted by area. Price areas are separated by the black lines.

The area prices show the same trend as the system prices. The 2020 and 2030 scenarios show significantly lower prices compared to the 2005 scenario. The area prices also show a clearer reaction to the offshore grid than the system prices. Adding the offshore grid causes area prices to increase in Denmark, Norway and Sweden/Finland and Germany. The area prices of UCTE and the Netherlands display a somewhat more ambivalent reaction to the offshore grid. In the 2020 scenarios the offshore grid causes prices in UCTE and the Netherlands to increase slightly, while for the 2030 scenarios the effect is the opposite; area prices are lower with the offshore grid than without it.

It is necessary to take note of the area prices in NO-N and NO-M in scenario 4. The price duration curves in Figure 11 show that prices very often will be zero, and the rest of the time they are very low. This is not profitable for power producers in the areas and it is therefore not realistic. It does however serve as a good example of the necessity of a strong transmission grid if such a large expansion for wind power in these areas is to take place. Adding the offshore grid will in this situation have a significant effect (area prices are more than doubled), as is demonstrated by the area prices of scenario 5. An expansion of the onshore main transmission corridors within and out of Norway will also significantly raise area prices, as is demonstrated by scenario 6.

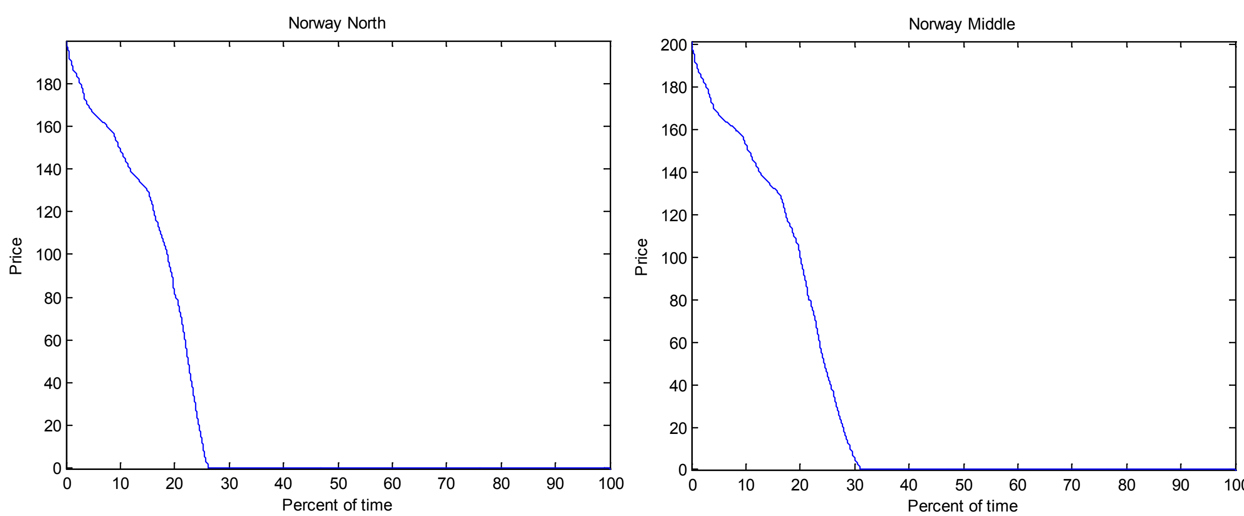


Figure 11: Price duration diagrams of NO-N and NO-M in scenario 4.

5.3 Energy costs

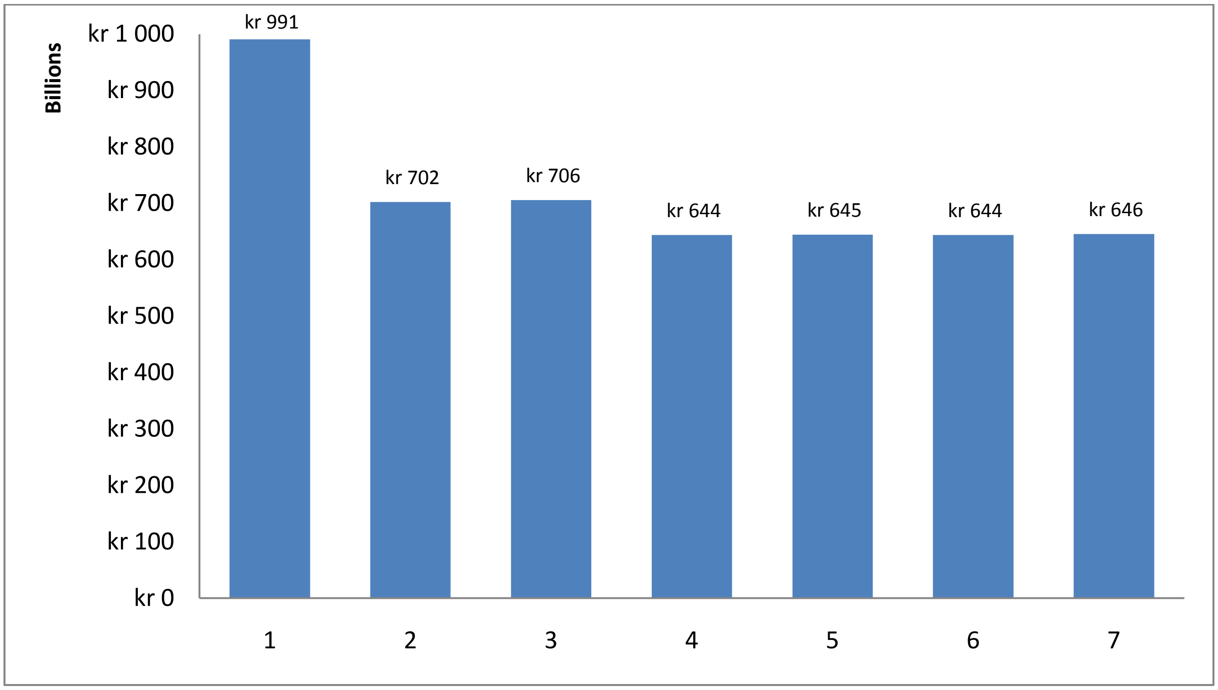


Figure 12: Each scenario's total energy costs in bill. kr.

The yearly costs of energy consumption are directly dependent on the energy prices in each area. Wind power will cause a significant reduction in energy costs. Realistically this reduction may be expected to be smaller, due to the market reacting to lower energy prices by increasing consumption. As explained earlier, consumption does not react to changes in price. Scenarios with offshore grids have higher yearly energy costs.

5.4 The offshore grid costs

As explained in chapter 2.5 on page 4, the costs of the offshore grid and its onshore connections are dependent on cable capacities. Offshore to onshore cables are dimensioned according to installed offshore wind power capacities. This means that the offshore grid costs will depend both on the amount of installed offshore wind power and on whether or not there are any interconnections between offshore areas. This is demonstrated in Figure 14.

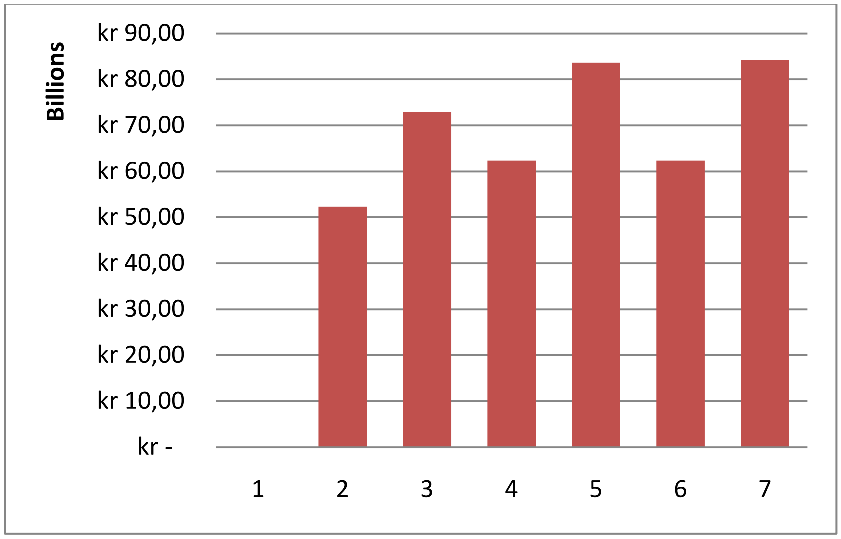


Figure 14: Yearly cost of the offshore grid, sorted by scenario.

Adding the costs of the offshore grid connections to the total energy costs of each scenario gives an indication of the total social benefit of these wind power expansions and an eventual offshore grid. This is shown in Figure 13.

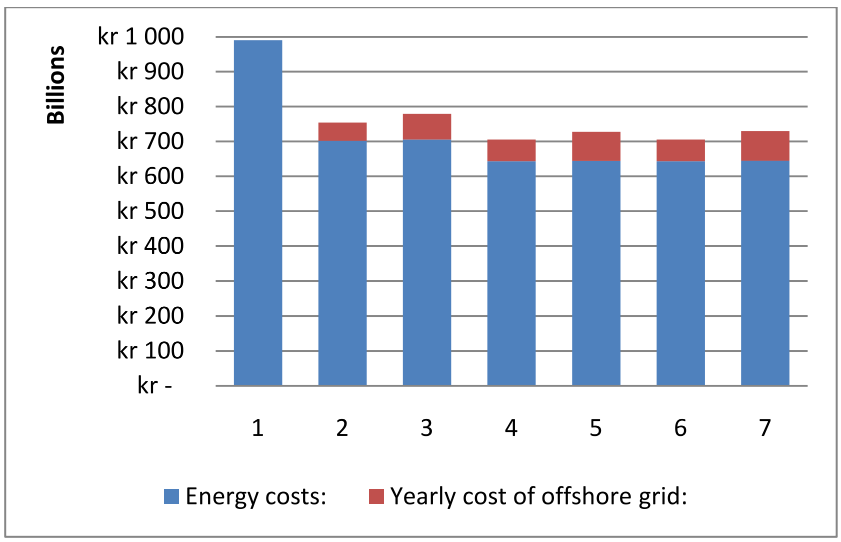


Figure 13: The combined yearly costs of energy consumption and offshore grids

In the current layout of the offshore grid, all adjacent areas are interconnected as illustrated in Figure 4 on page 25. It is likely that there are more interconnections than strictly necessary. A rationalization of the number of interconnections will reduce the costs of the grid and may not impact its flexibility to a large extent. This possibility is explored further in chapter 5.9: *Rationalizing the offshore grid*.

5.5 Lost energy from hydro reservoir spillage and wind power production curtailment

There is virtually no lost energy from hydro or wind generators in scenario 1. Balancing these amounts of wind and hydro power seems to be unproblematic. This is changed considerably in scenarios 2 – 7, where the amount of lost potential energy is in the range of several TWh. Compared to the actual energy inflow of each energy source, lost energy in most cases constitutes less than 3% of the total energy inflow, as seen in Figure 15. The exception is hydro energy in scenario 4, where more than 15% of all hydro inflow is lost. It is therefore necessary to take a closer look at lost energy in scenario 4 to determine the cause of this loss.

Scenario	Hydro reservoir spillage [MWh]	Lost wind power [MWh]
1	-	172,47
2	2 515 678,81	6 003 317,72
3	955 996,11	1 876 023,97
4	32 166 089,58	6 012 468,34
5	6 072 274,16	2 262 372,80
6	4 347 575,17	4 989 086,15
7	2 603 573,82	2 124 274,90

Table 23: Yearly lost hydro and wind energy in MWh.

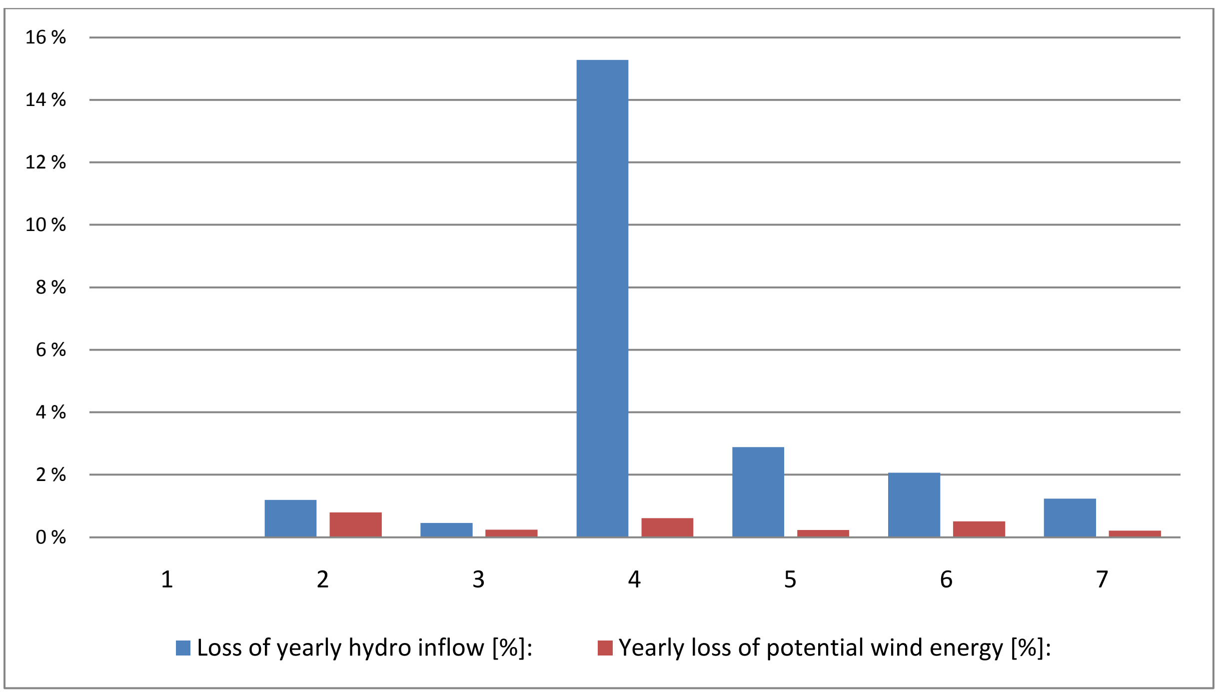


Figure 15: Yearly lost potential hydro and wind energy in percent, sorted by scenario.

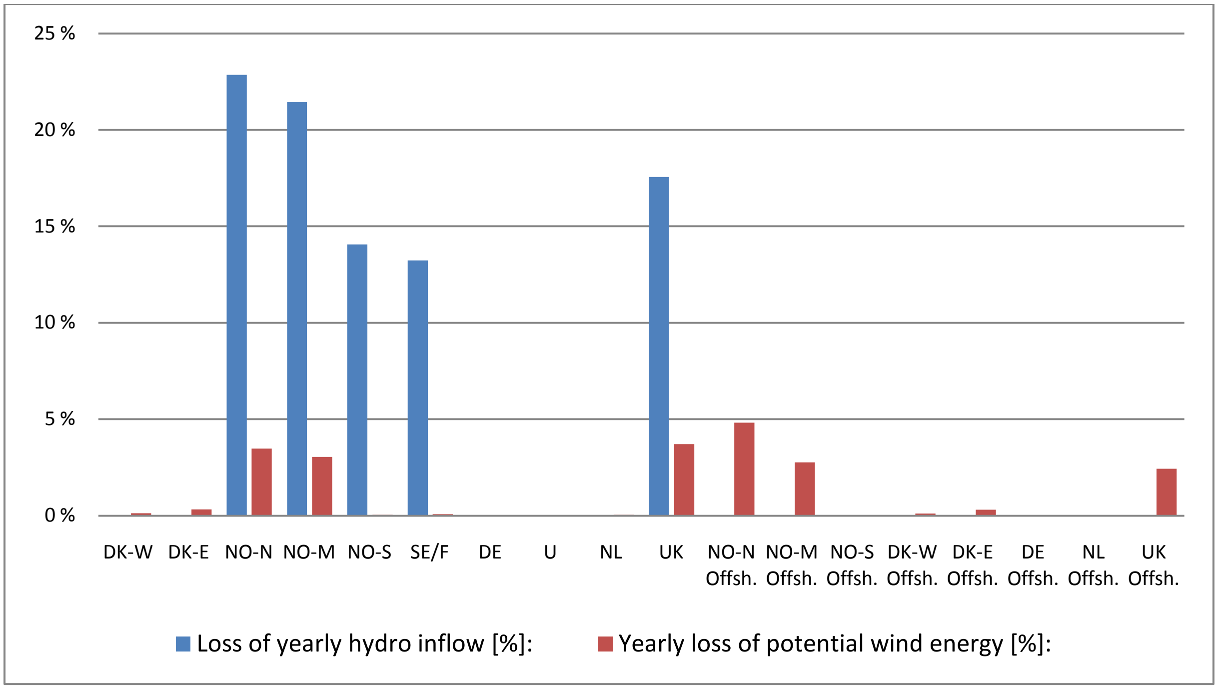


Figure 16: Yearly energy loss per area in scenario 4.

As described in chapter 3.2.3 *Transfer capacities in the 2030 scenarios* on page 23, scenario 4 is the 2030 scenario with the weakest grid configuration. The model seems to prioritize wind power production before hydro power. The transmission grid is unable to transport enough energy out of these areas, given its current configuration. This causes a build-up of water in the reservoirs, which in turn causes longer periods of reservoir overflow. During reservoir overflow the water value of the reservoir falls to zero. The effect is quite evident in all areas, especially in the middle and north of Norway. Another effect is that energy prices in these areas frequently will be close to or equal to zero, resulting in unfavourable operating conditions for power producers. Figure 11 on page 33 shows this. These areas are also very far away from continental Europe where the excess energy more easily could have been utilized.

Since hydro power in Germany is modelled as a thermal generator, any eventual reservoir spillage in this area remains an unknown.

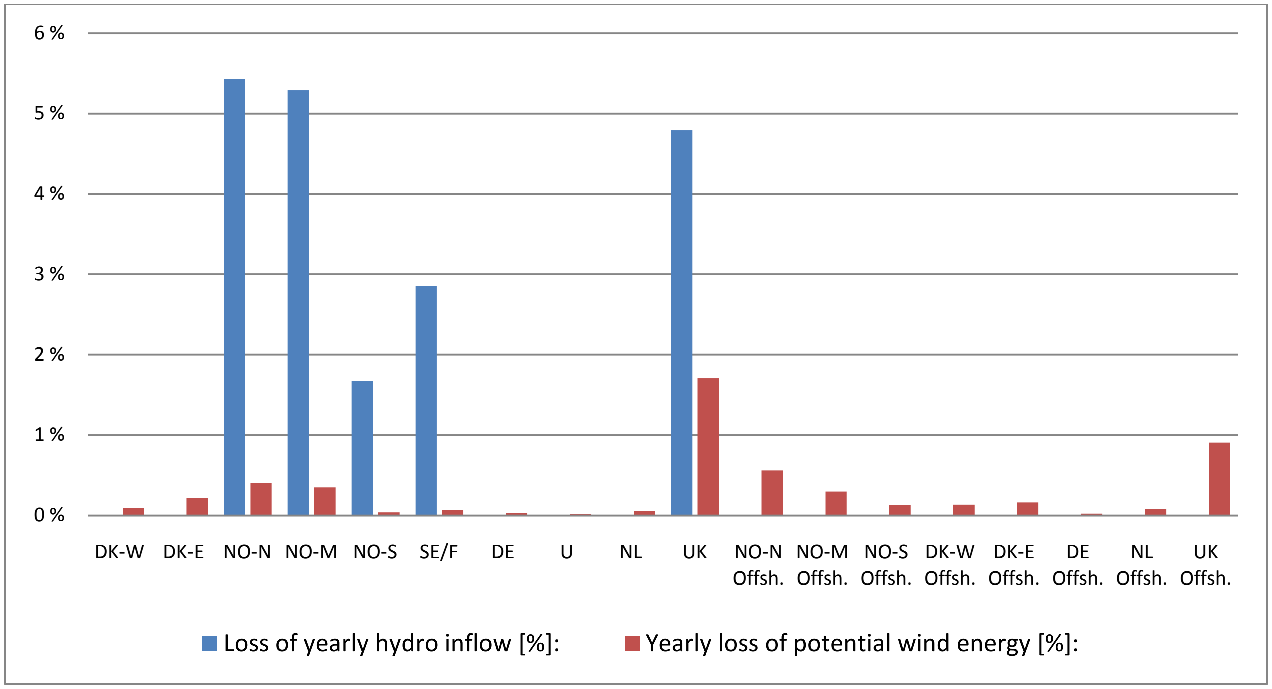


Figure 17: Yearly energy loss per area in scenario 5.

In the case of scenario 4, the benefits of adding the offshore grid are substantial. This is done in scenario 5. The result is a significant reduction of lost hydro energy, as shown in Figure 17. In the given circumstances, the presence of the offshore grid will be a significant boon to both wind and hydro power producers.

Scenario 6 shows that the problem in scenario 4 also can be solved by strengthening the existing onshore transmission corridors. Scenario 7 shows that the offshore grid will reduce lost energy, even with a stronger onshore grid. The benefit of the offshore grid is smaller in this case, though.

5.6 Transmission grid use

Historical electricity transfer data for 2005 were downloaded from UCTE's web site and compared to the simulated transfers of scenario 1, as shown in Figure 18. [21] Historical transfer data between the Norwegian areas were not found.

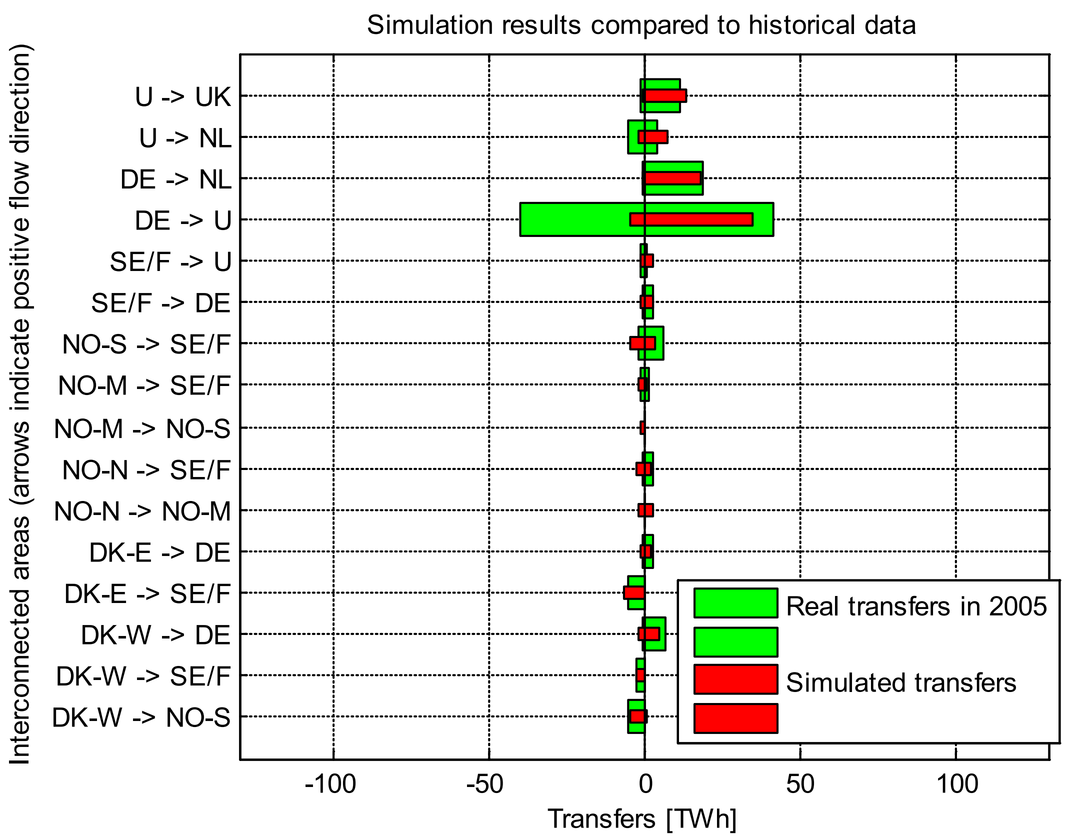


Figure 18: Simulated yearly energy transfers per transmission corridor in scenario 1 compared to historical transfer data from 2005. [21]

Simulated transfers in scenario 1 correspond fairly well to the historical data when taking the roughness of the model into consideration. This indicates that the energy prices and generation capacities of the individual areas are relatively realistically balanced against each other.

The Netherlands and the UK are importers, corresponding well with their high energy prices compared to the other areas. In Scandinavia SE/F is mostly exporting to its neighbours, while transfers generally tend to flow south towards Denmark and continental Europe.

Full energy transfer and line loading plots for scenarios 2 – 7 can be found in *Appendix 5: Simulated energy transfers and mean line loading per* scenario on page 62.

As the installed wind power production capacity in the system increases, so does the total amount of transferred energy. The UK and the Netherlands still import from neighbouring areas, but to a lesser degree. This is caused by their respective wind power expansions both on- and offshore.

In scenarios 2 – 7, the Norwegian areas export more than they import. Transmissions in Scandinavia still tend to flow from north to south toward the continent. SE/F has become a net importer of Norwegian energy.

It is interesting to note that the presence of the offshore grid causes the UK and the Netherlands to import energy from other offshore areas through their own offshore areas.

Grid connections from offshore to onshore areas are, as mentioned before, dimensioned to be able to handle maximum power output from corresponding offshore wind farms. An analysis of the average loading of transmission lines reveals that this method may lead to an over-dimensioning of the off- to onshore connections. As demonstrated in Figure 19, mean loading of these is for the most part lower than half of the available capacity. This may indicate that the line capacities are larger than necessary, which in turn means that the costs of the offshore connections may be higher than necessary. However, such a capacity reduction will cause energy to be lost. Detailed studies will be necessary to determine the optimal grid configurations.

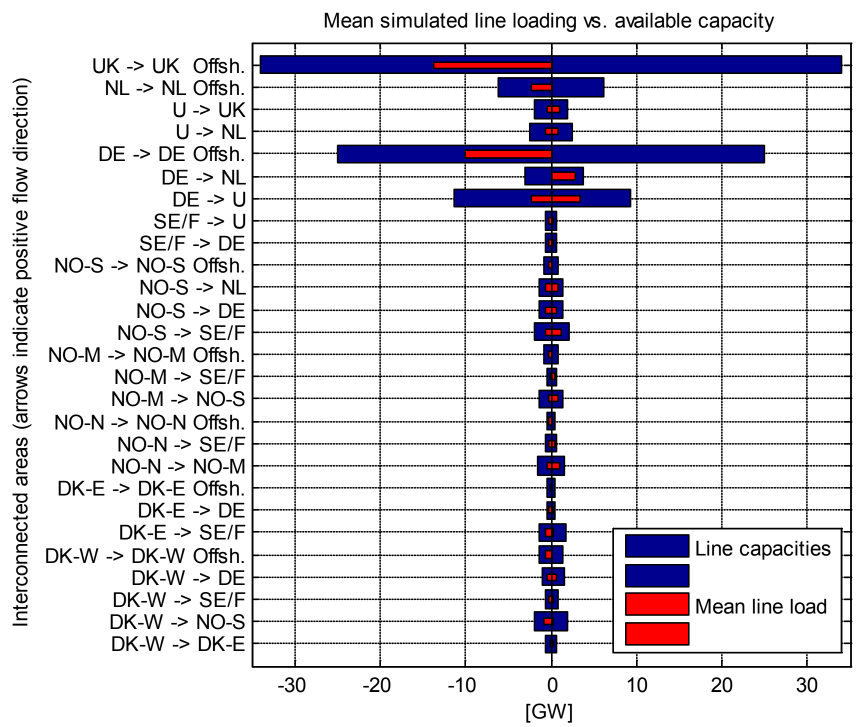


Figure 19: Plot of mean line loading in scenario 2.

5.7 Correlation of production between offshore wind farms

Correlations between the wind farms correspond well to expectations. [4 pp. 14, 19] Correlations of production patterns between farms situated close together are higher than between farms that are spaced far apart. Figure 20 shows the wind farms in scenario 2, but the correlation factors seem to be very much the same for all scenarios. The presence of an offshore grid does not seem to have any significant impact on the correlation factors either.

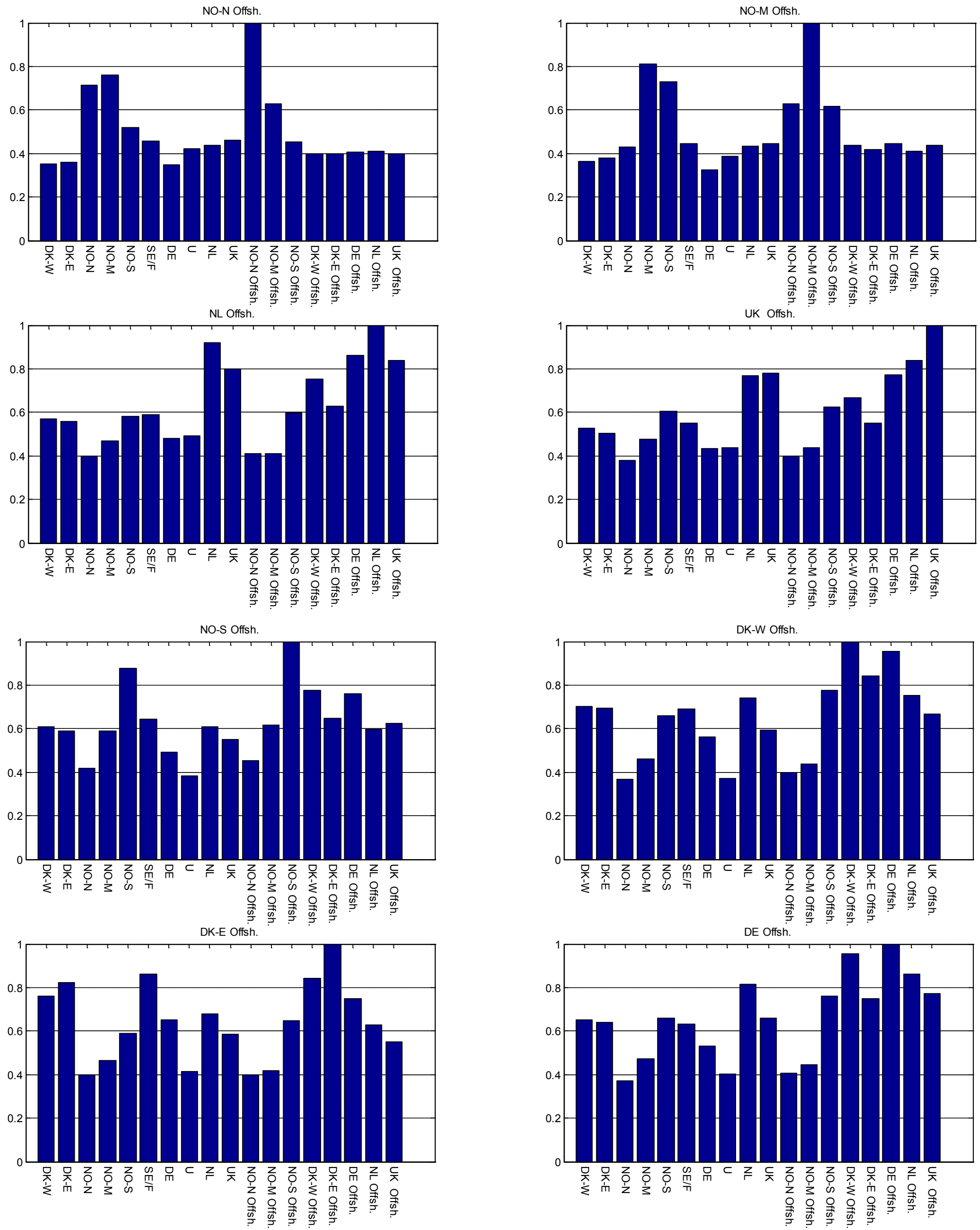


Figure 20: Plot of correlation between wind farms.

There is a fairly high correlation between wind farms in the southern part of the North Sea. This is to be expected, since they are situated close together. The result is that the production patterns of these farms can be expected to be somewhat similar. Periods of high and low production may in other words occur within the same time frame for these farms. This will present an opportunity for farms situated further apart from the others, in this case particularly for the farms situated off the coast of NO-N and NO-M. Since these farms seem to have a lower degree of correlation to other offshore wind farms, they may in some cases be able to maintain high production while winds in the south are low. Given sufficient transmission capabilities to the continent, the offshore wind farms of NO-N and NO-M may contribute to balancing out fluctuations in wind power output on the continent.

5.8 Wind power's impact on hydro power production patterns

Hydro power's ability to store potential energy and to easily and quickly regulate production up or down makes it very well suited for balancing the varying power output from wind farms. The introduction of large quantities of wind power will for this reason significantly influence the production patterns of hydro generators. To investigate this, 72 continuous hours of production data from Norway South were evaluated. Production data were taken from scenarios 1, 2 and 3. Data was taken from the same time period in all scenarios. Load data from the same 72 hours is also evaluated. The load is the same for all three scenarios, as explained earlier.

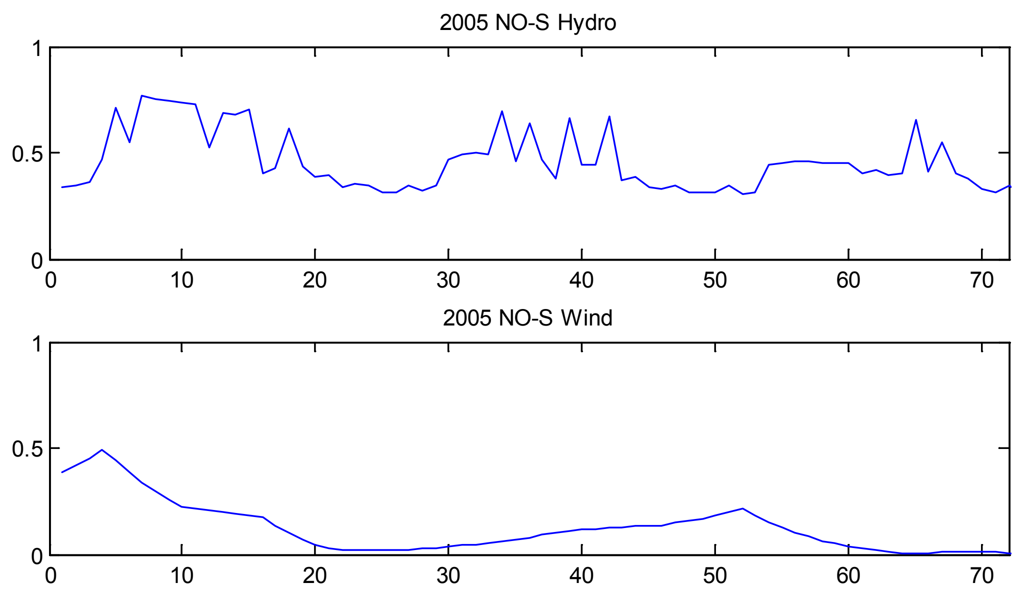


Figure 21: Hydro and wind production in the given time period in scenario 1.

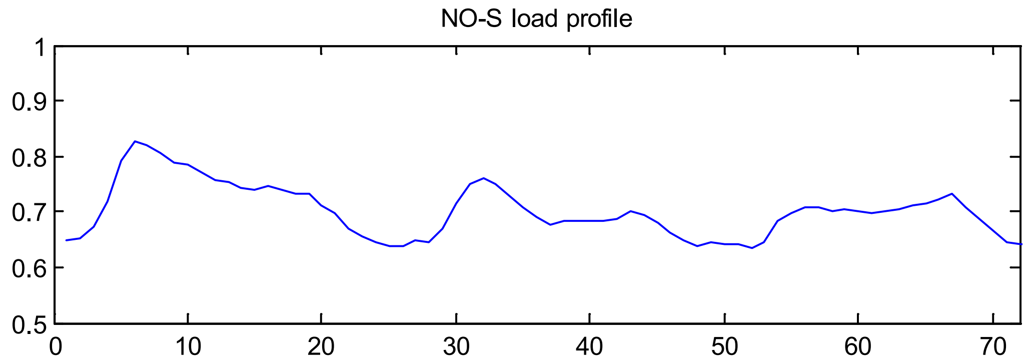


Figure 22: Load profile in the given time period. This is identical for all scenarios.

In scenario 1, installed capacity in NO-S is only 9 MW, which is not enough to influence hydro power production in any significant way. Installed wind power in neighbouring areas can be assumed to only have capacity to supply local loads, and will therefore not have any significant impact on hydro power production in NO-S. The hydro power output seems to follow the load profile quite well, as seen in Figure 21.

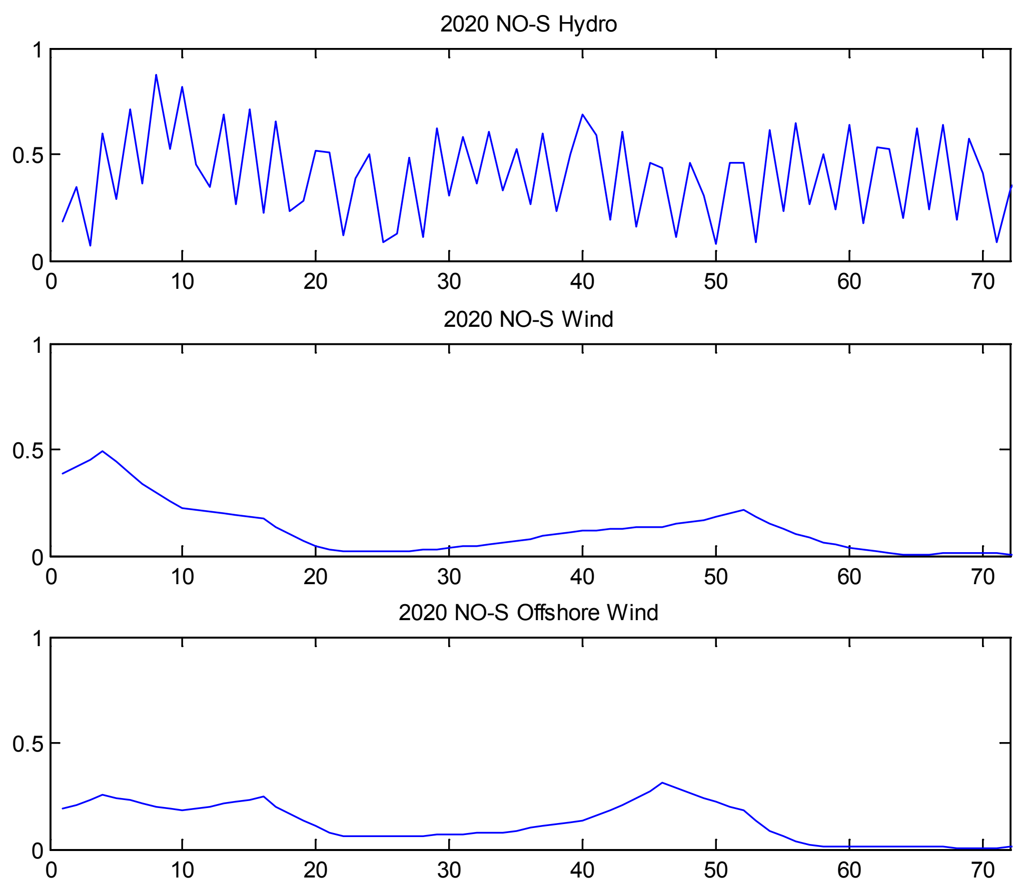


Figure 23: Hydro and wind production in the given time period in scenario 2.

In scenario 2, NO-S has an installed onshore capacity of 1883 MW and an installed offshore capacity of 766 MW. All surrounding areas also have a larger share of wind power installed. This has an evident effect on hydro power production in the area. As shown in Figure 23, hydro production varies a lot from hour to hour. Some of this behaviour may be caused by balancing of wind power both in NO-S and in its neighbouring areas. Some of it is probably caused by the model itself. It is still possible to see that the hydro power production profile roughly corresponds to the load profile, although the overall production level is lower than in scenario 1.

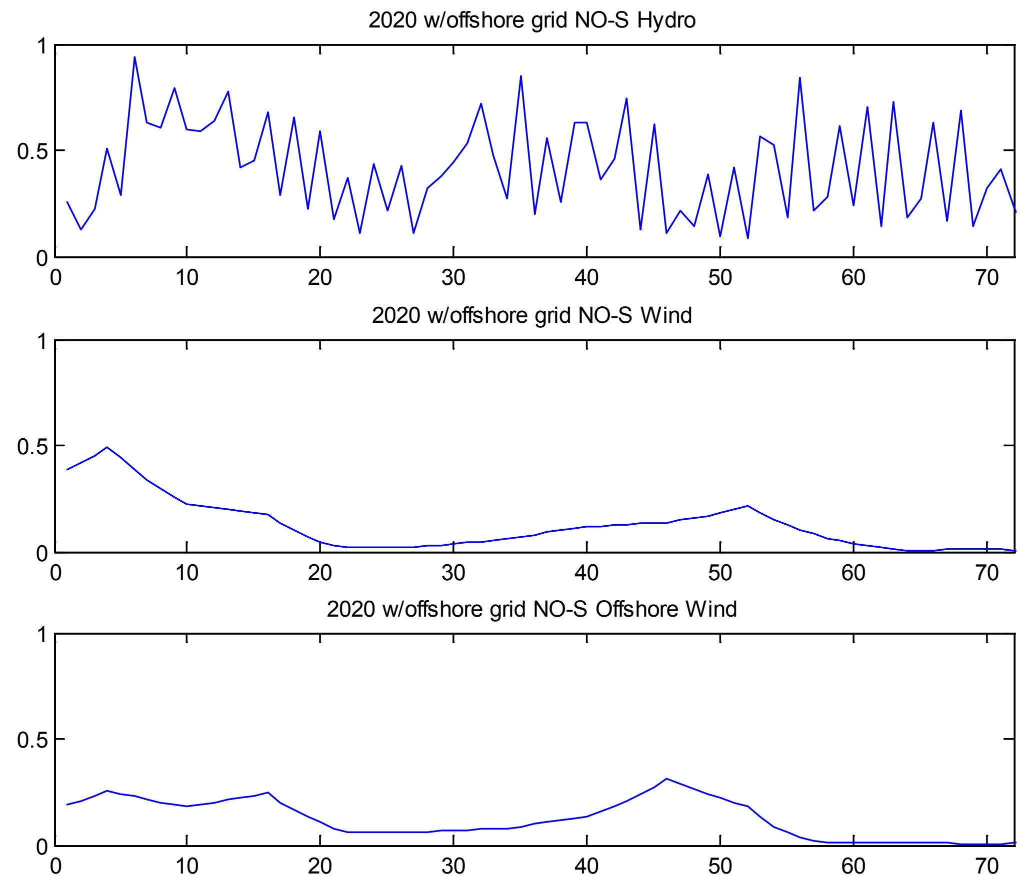


Figure 24: Hydro and wind production in the given time period in scenario 3.

The introduction of the offshore grid does seem to alter the zigzagging behaviour of the hydro generators. Average hydro production seems to have increased slightly. It is likely that the increase in transmission capacity provided by the offshore grid makes it possible to utilize both hydro and wind more efficiently by allowing a greater amount of export to the continent.

Some of the hour-to-hour zigzagging behaviour of the hydro power can be explained by the workings of the simulation model itself. In periods where water values in two neighbouring areas are nearly equal, hydro production in the two areas will start alternating from hour to hour. The area with the lowest water value will export power to the other area one hour, thereby increasing production in one area while reducing it in the other. If water values in the first area then increase above water values in the second area due to reduced reservoir levels, the balance is shifted and the second area will start exporting to the first.

It is still to be expected that the introduction of wind power will cause increased fluctuations in hydro power generation. However, as is demonstrated in the above figures, these variations in wind power output will be more gradual. With well-developed wind forecasting methods it should be possible to foresee changes in wind conditions and to plan future production.

Figure 25 shows that reservoir levels in scenarios 2 and 3 are significantly higher than in scenario 1. This is tied to the general reduction in hydro power generation caused by the wind farms. Combined with the expected increase in precipitation and mean temperature due to global warming, it is likely that hydro reservoir levels will be considerably higher in the future. [20 p. 18]

Only a very small part of the simulation data has been investigated with respect to this subject. More detailed studies into this subject will be necessary in order to create a more complete picture.

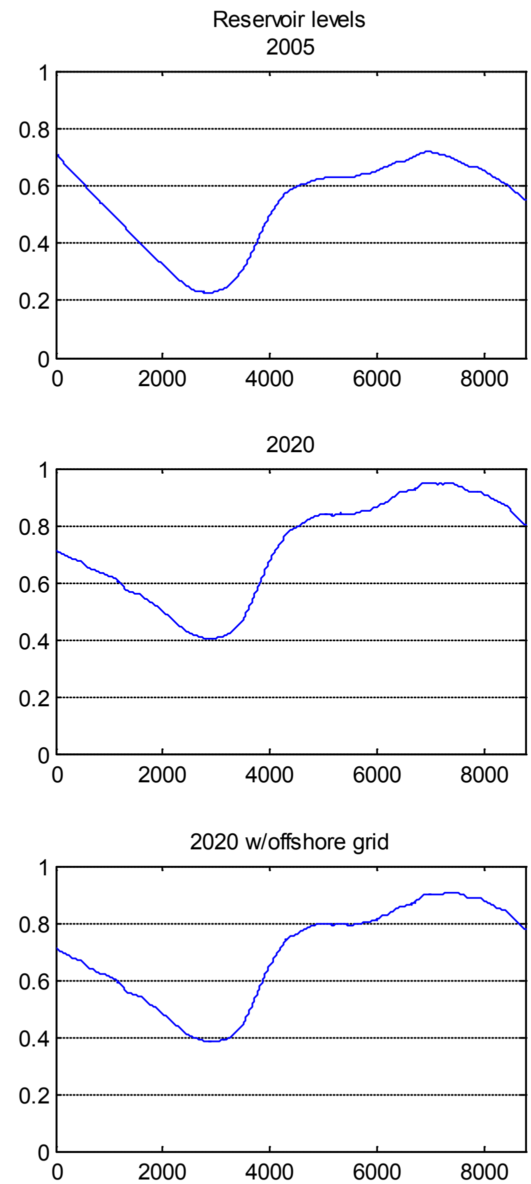


Figure 25: Reservoir levels of NO-S in scenarios 1, 2 and 3 respectively.

5.9 Rationalizing the offshore grid

As mentioned before, the offshore grid used in these simulations provides a large degree of flexibility in transfers between offshore areas. Given its unrealistic configuration it is more expensive than it needs to be. It may therefore be desirable to investigate whether a rationalized version of the grid will be able to offer similar characteristics at reduced costs.

The scenario 3 has been modified in the following manner:

- The number of interconnections have been reduced
- Line capacities of the remaining interconnections between offshore areas have been reduced so that they are closer to mean line loading as it is shown in Figure 35 in *Appendix 5: Simulated energy transfers and mean line loading per* scenario.

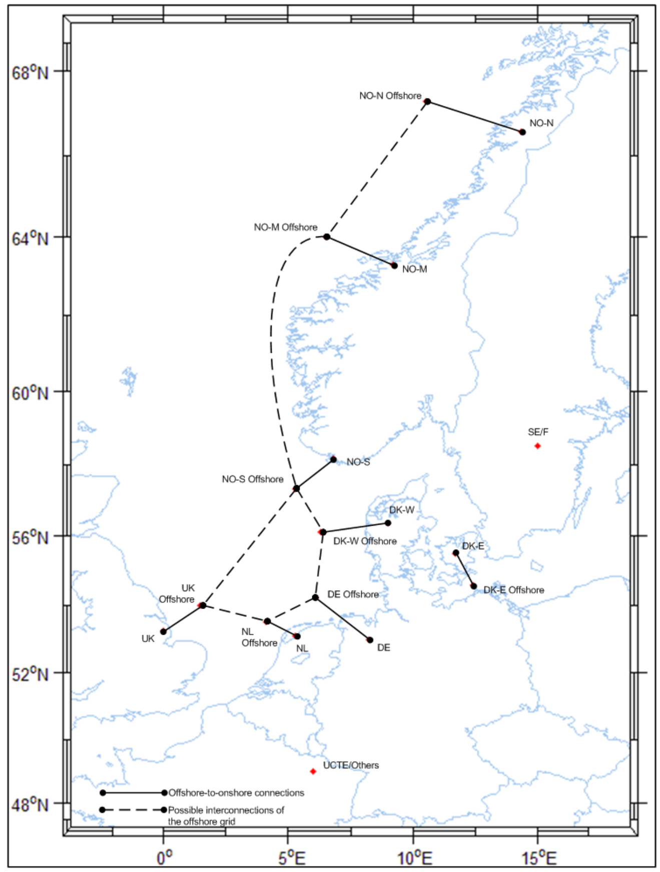


Figure 26: Suggestion for a rationalized version of the offshore grid.

This resulting changes in the offshore grid shown in Table 24 and Figure 26. Apart from these changes, the resulting scenario is identical to scenarios 2 and 3.

To, *i* / From, *i*	NO-N Off.	NO-M Off.	NO-S Off.	DK-W Off.	DK-E Off.	DE Off.	NL Off.	UK Off.
NO-N Off.	–	350						
NO-M Off.	350	–	900					
NO-S Off.		900	–	1000				1000
DK-W Off.			1000	–		600		
DK-E Off.					–			
DE Off.				600		–	700	
NL Off.						700	–	1000
UK Off.			1000				1000	–

Table 24: The rationalized offshore grid.

The rationalized grid offers similar performance compared to the standard offshore grid in scenario 3. There are slight differences in generation distribution, and scenario 3 seems to favour hydro and wind generators a bit more than the rationalized grid does.

The main motivation behind the rationalized grid was cost reduction and this seems to have been achieved. Whereas the standard offshore grid configuration has a yearly cost of 72.9 billion kr, the rationalized grid has a yearly cost of 58.5 billion kr. As is illustrated in Figure 28, the rationalized grid seems to cause slightly higher costs due to energy consumption, but overall the combined costs are lower than for scenario 3.

The percentage of lost hydro and wind energy is higher for the rationalized grid, but only very slightly. This is shown in Figure 29. The rationalized grid is still an improvement on scenario 2 though.

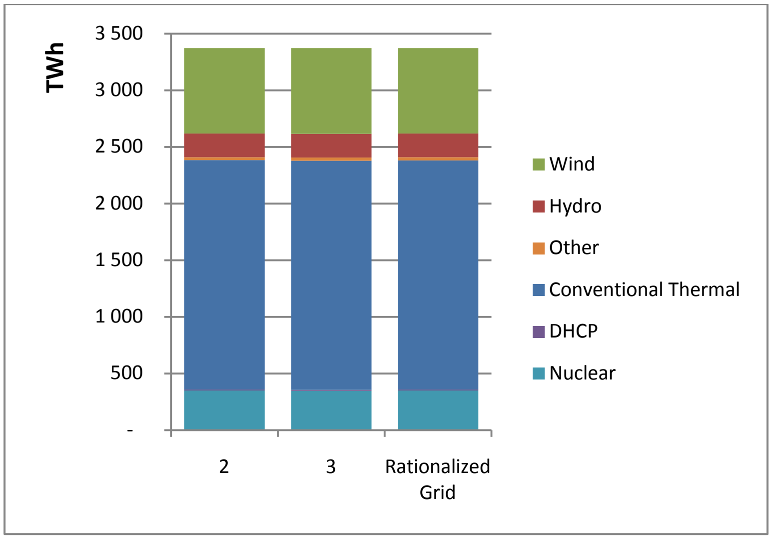


Figure 27: Yearly energy production in the compared scenarios.

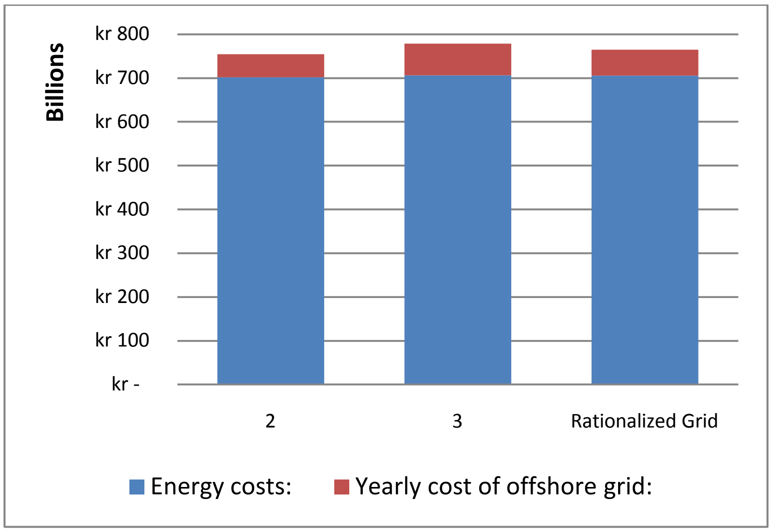


Figure 28: Yearly costs of energy consumption and offshore grids.

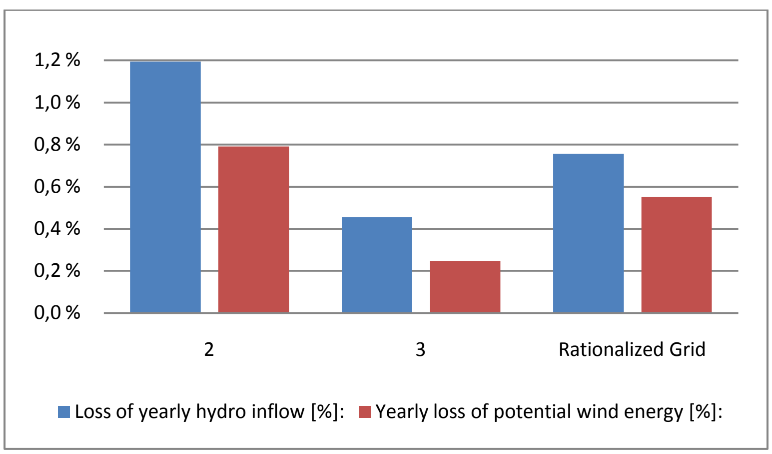


Figure 29: Yearly lost potential hydro and wind energy.

5.10 Reservations

When considering the results presented in this chapter it is important to bear in mind that both the simulation model and the data used in the scenarios are based on a number of simplifications and assumptions. This makes it necessary to focus on the general trends of development rather than on specific numerical values.

As explained earlier, the reservoir capacity of hydro power in the UK is based on an assumption and inflow data is based on the inflow data from the area NO-N. This makes the simulation results of hydro power generation in the UK inaccurate at best. However, this does not seem to affect the overall performance of the simulations to a significant degree. The quantity of hydro power installed in the UK is relatively small when compared to the other energy sources in the area. This is in all likelihood contributing to limit the consequences of these inaccuracies.

The model's water value calculations are based on a regression model based on Norwegian reservoir data for the period 2000 – 2006. It is constructed to fluctuate around an average reservoir and energy price level. [2 pp. 18 - 21]Water value calculations are therefore well adapted to power system conditions similar to present conditions, like scenario 1 which is set in 2005. However, when introducing such large quantities of wind power (as in scenarios 2 – 7), the power system conditions are altered significantly. It is therefore likely that the model in these scenarios functions less than optimally.

In reality wind farms will be spread in smaller units over a larger geographical area, rather than aggregated together in single points as win this model. It is therefore likely that the smoothing effect of the wind farms will be greater than what is seen in these simulations.

6 Conclusion

Given the number of assumptions made in the grid cost calculations and in the model at large, it is more important to focus on general trends than on concrete numerical values.

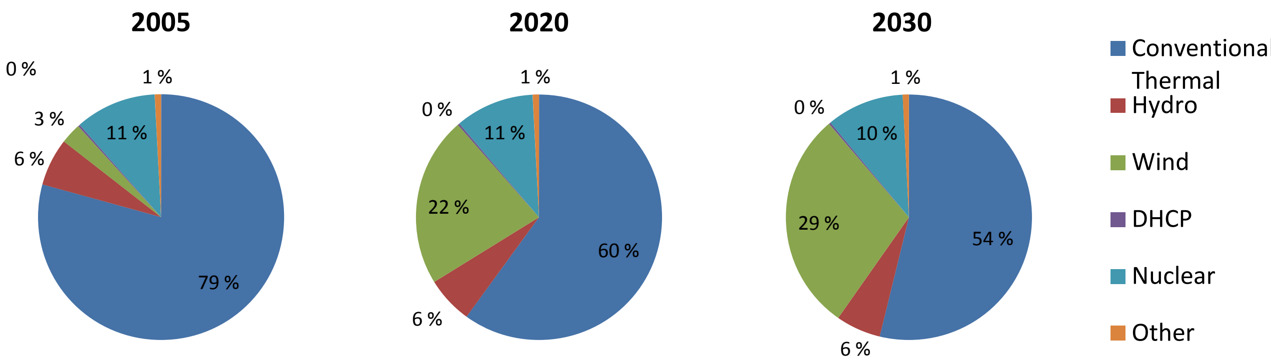


Figure 30: Yearly energy production in each scenario sorted by generator type. The numbers in the table are given in MWh.

Wind power is able to replace quantity of energy originally produced by conventional thermal generators. Most generator types are affected by the increasing amount of wind power, but conventional thermal generators are affected the most, since these constitute the most expensive forms of generation in the system. It is therefore obvious that such an extensive increase of wind power will have a significant positive environmental effect, especially with respect to CO2-emissions.

It is clear that increasing the amount of on- and offshore wind power in the European power system will have a beneficial impact to society's energy costs. Realistically, price reductions will probably be smaller than the results shown in Figure 31. In reality, consumers would probably have reacted to the lowered energy prices by increasing

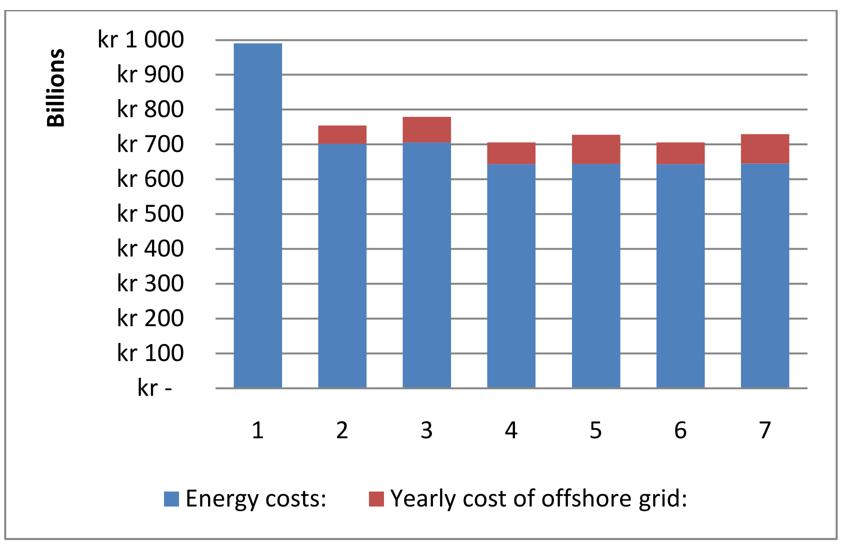


Figure 31: The combined yearly costs of energy consumption and offshore grids.

consumption.

The offshore grid seems to be mostly beneficial to the power producers, by causing slightly higher energy prices and providing a measure of flexibility as to where offshore wind power production is sent. The construction of offshore wind farms and an eventual offshore grid will be costly. Seen together with the general reduction of energy costs in the system there is still a significant benefit to society, as Figure 31 illustrates.

In scenario 1 wind and hydro power is utilized optimally, and close to no potential energy is lost. In most of the simulated scenarios the amount of lost potential hydro and wind energy stays below 3%. This corresponds to an amount of yearly lost potential energy somewhere between 2 and 12 TWh, depending on scenario. The exception is scenario 4, in which approximately 15% (ca. 32 TWh) of hydro reservoir inflow is lost.

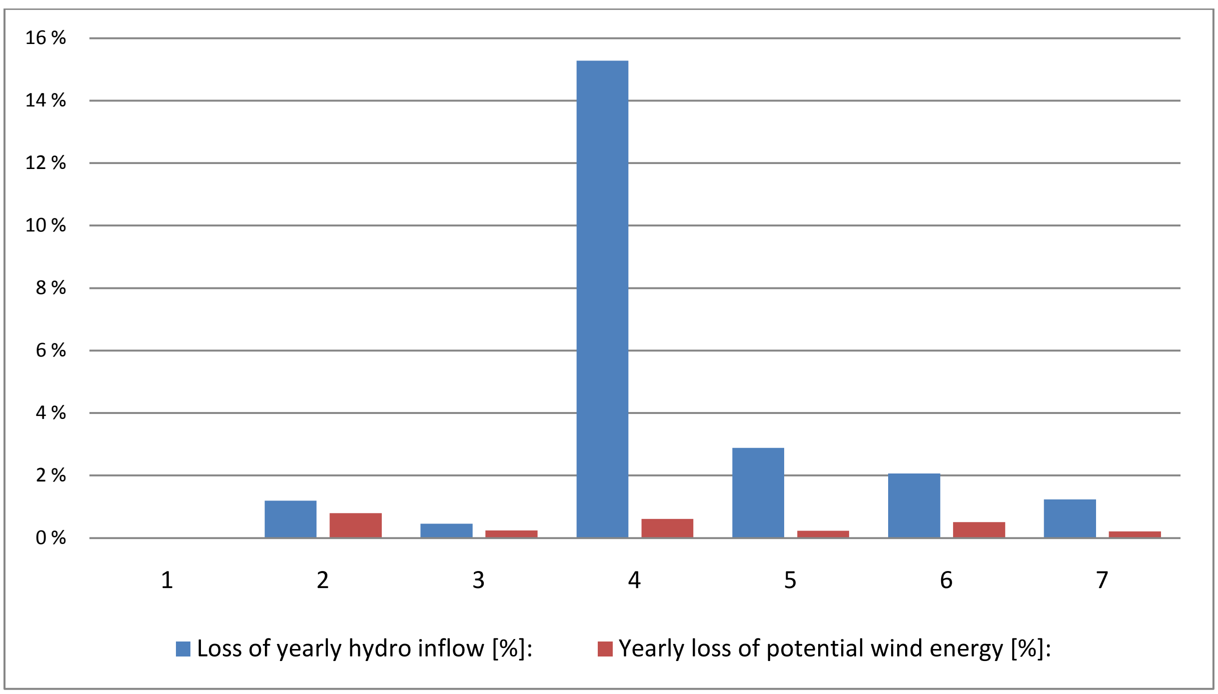


Figure 32: Yearly lost potential hydro and wind energy in percent, sorted by scenario.

This massive loss of potential hydro energy is caused by two main factors: The combination of large amounts of wind power competing with hydro power, and a transmission grid which is unable to transport enough of the excess energy out of the areas in question. This effect is evident in all areas with hydro power and the Norwegian areas are the most affected. As scenarios 5 -7 show, this problem is avoided either by the presence of an offshore grid, by expanding transmission corridors onshore or with a combination of both. Increased transmission line capacities are in any case essential in being able to handle the additional wind power generation in the 2030 scenarios.

A comparison between simulated transmission data from scenario 1 and historical transmission data from 2005 show that this scenario produces relatively realistic energy flows in the system. The Netherlands and the UK are importing energy. This makes sense, as these countries have the highest energy prices in the system. In Scandinavia, Sweden/Finland is mostly exporting to its neighbours, while transfers generally tend to flow southwards towards continental Europe. In scenarios 2 – 7, the Norwegian areas have started to export more than they import, while SE/F has become a net energy importer, most likely of cheap Norwegian electricity. The offshore grid causes the UK and the Netherlands to start importing large amounts of energy from other offshore areas through their own offshore areas.

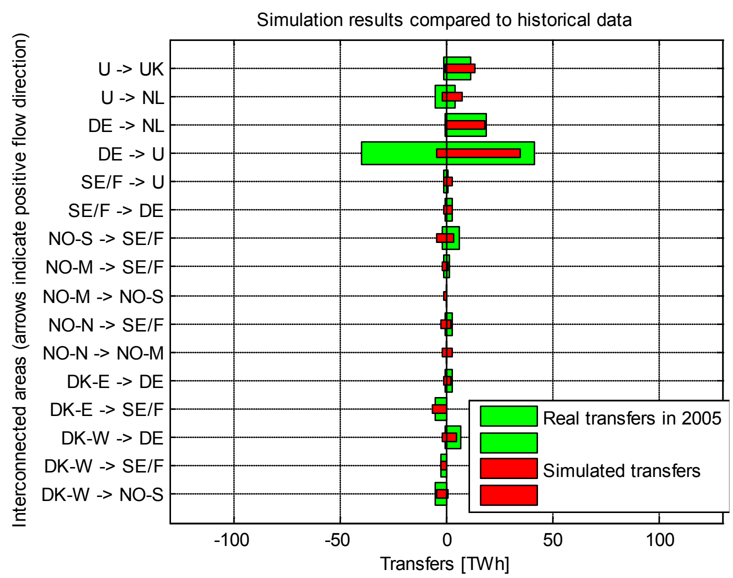


Figure 33: Simulated yearly energy transfers per transmission corridor in scenario 1 compared to historical transfer data from 2005. [21]

An analysis of the average loading of the system’s transmission lines reveals that the offshore grid configuration is over-dimensioned, and that a rationalization of the grid capacities may be in order to achieve a more cost-effective grid. The simplified offshore grid rationalization performed in chapter 5.9 shows that it is possible to attain a much more cost-effective offshore grid without significantly affecting the benefits of such a grid.

Wind power output from offshore wind farms in NO-M and NO-N will be largely uncorrelated to wind farms situated in the southern part of the North Sea. The offshore wind farms of DK-W, DE, NL and UK have a higher degree of correlation, and will have high or low production within the same time frame. Given sufficient transfer capabilities, NO-M and NO-N may contribute to balancing wind power output fluctuations on the continent and vice versa.

An increased amount of wind power in the power system will have a noticeable impact on hydro power production patterns. Hydro power producers will have to deal with more frequent fluctuations in production and increased average reservoir levels. It should be noted that some of the most frequent fluctuations in power production can be explained by the workings of the simulation model itself. The combination of a stronger transmission grid and reliable wind forecasting tools should make these challenges manageable.

The future expansion of wind power in and around the North Sea will be very beneficial, in both economic and environmental respects. However, if these plans are going to be successful it is vital that corresponding transmission grid upgrades and expansions are performed. This project has served to shed light on some of the issues that may arise when integrating wind power on such a scale. More detailed studies will be needed to properly and accurately investigate these issues further.

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Appendix 1: TradeWind wind farm power curves

Wind speed [m/s]	Lowland	Offshore
0	0 %	0 %
1	0 %	0 %
2	0 %	0 %
3	1 %	1 %
4	3 %	2 %
5	6 %	5 %
6	11 %	8 %
7	17 %	14 %
8	25 %	20 %
9	35 %	29 %
10	47 %	40 %
11	60 %	53 %
12	72 %	64 %
13	81 %	76 %
14	88 %	84 %
15	92 %	89 %
16	94 %	89 %
17	94 %	89 %
18	94 %	89 %
19	90 %	89 %
20	83 %	83 %
21	72 %	71 %
22	56 %	54 %
23	38 %	36 %
24	23 %	18 %
25	11 %	6 %
26	4 %	0 %
27	0 %	0 %
28	0 %	0 %
29	0 %	0 %
30	0 %	0 %
31	0 %	0 %
32	0 %	0 %
33	0 %	0 %
34	0 %	0 %
35	0 %	0 %

Table 25: Wind farm power curves used when generating wind series.

Appendix 2: Calculation of Norwegian wind power in 2020 and 2030

Onshore wind power estimates

Area	Feasible 2015 [MW]	Feasible 2025 [MW]	Sum [MW]
1	100	850	950
2	750	0	750
3	300	200	500
4	500	750	1250
5	1750	450	2200
6	350	0	350
7	250	200	450
8	700	0	700
Sum	**4700**	**2450**	**7150**

Price area	Feasible 2015 [MW]	Feasible 2025 [MW]	Sum [MW]
NO-N	1150	1050	2200
NO-M	1667	1050	2717
NO-S	1883	350	2233
Sum	**4700**	**2450**	**7150**

Table 26: Onshore wind power in Norway.

The report "*Mulighetsstudie for landbasert vindkraft 2015 og 2025*" (Eng. translation: "*Feasibility study of land based wind power 2015 and 2025*") by NVE contains the above estimates for future Norwegian onshore wind power. [9 p. 21] In this report Norway is divided into 8 areas. These are converted into the three areas used in this project: NO-N, NO-M and NO-S. Areas 1, 2 and 3 are merged together to NO-N. NO-M consists of area 4 and 2/3 of area 5. NO-S consists of the rest of area 5 and areas 6, 7 and 8.

For the purposes of this project, the estimates for 2015 are assumed to be valid for 2020, while the estimates for 2025 are assumed to be valid for 2030.

Offshore wind power estimates

The estimation is based on the pre-notified offshore wind projects reported to the NVE. [10] to make scenarios for 2020 and 2030 it is assumed that 1/3 of the total capacity in each area will have been built by 2020, and the remaining 2/3 by 2030. It is reasonable to assume that construction will happen faster between 2020 and 2030, since more of the infrastructure and better technologies will be available compared to before 2020.

		Capacity [MW] in year	
	Name	**2020**	**2030**
NO-S	Sørlige. Nordsjøen	333	999
	Utsira	100	300
	Ægir	333	999
	Sum	**766**	**2298**

		Capacity [MW] in year	
	Name	**2020**	**2030**
NO-M	Stadtvind	333	999
	Fosen	200	600
	Mørevind	333	999
	Sum	**866**	**2598**

		Capacity [MW] in year	
	Name	**2020**	**2030**
NO-N	Gimsøy	83,3333333	250
	Lofoten	250	750
	Selvær	150	450
	Sum	**483,333333**	**1450**

Summary

	Capacity [MW] in year	
Name	**2020**	**2030**
NO1	766	2298
NO2	866	2598
NO3	483,333333	1450
Sum total	**2115,33333**	**6346**

Table 27: Estimated Norwegian offshore wind power in 2020 and 2030.

Appendix 3: Detailed marginal cost calculations for the UK

$$\text{Coal:} MC_C = A_C + B_C x$$
$$\text{Start:} \quad x \approx 17560$$
$$y = 225.7$$
$$\text{Available prod. cap.} \approx 27570MW$$
$$\text{Stop:} \quad x = 17560 + 27570 = 45130MW$$
$$y = 291.9$$
$$A_C = 225.7$$
$$B_C = \frac{291.9 - 225.7}{45130 - 17560} = 0.0024$$
$$MC_C = 225.7 + 0.0024 \cdot x \left[{}^{\text{kr}}/_{\text{MWh}} \right]$$

$$\text{Gas:} MC_C = A_C + B_C x$$
$$\text{Start:} \quad x = 45130$$
$$y = 291.9$$
$$\text{Available prod. cap.} \approx 30200MW$$
$$\text{Stop:} \quad x = 44120 + 30200 = 75330MW$$
$$y = 619.6$$
$$A_C = 291.9$$
$$B_C = \frac{619.6 - 291.9}{75330 - 45130} = 0.0109$$
$$MC_C = 291.9 + 0.0109 \cdot x \left[{}^{\text{kr}}/_{\text{MWh}} \right]$$

$$\text{Other:} MC_C = A_C + B_C x$$
$$\text{Start:} \quad x = 75330$$
$$y = 619.6$$
$$\text{Available prod. cap.} \approx 3430MW$$
$$\text{Stop:} \quad x = 75330 + 3430 = 78760MW$$
$$y = 842.9$$
$$A_C = 619.6$$
$$B_C = \frac{842.9 - 619.6}{78760 - 75330} = 0.0650$$
$$MC_C = 619.6 + 0.0650 \cdot x \left[{}^{\text{kr}}/_{\text{MWh}} \right]$$

Appendix 4: Transmission matrices

The transmission matrix used in the 2020 scenario

From, \ To, j	DK-W	DK-E	NO-N	NO-M	NO-S	SE/F	DE	U	NL	UK	NO-N Off.	NO-M Off.	NO-S Off.	DK-W Off.	DK-E Off.	DE Off.	NL Off.	UK Off.
DK-W	–	600*			1950	740	1500							1400				
DK-E	600*	–				1700	550								400			
NO-N			–	1600*		600					500							
NO-M			1600*	–	1300*	600						900						
NO-S	1950			1300*	–	2050	1400*		1400				800					
SE/F	680	1300	700	500	1850	–	600	600										
DE	950	550			1400*	600	–	9230	3850							25000		
U						600	11250	–	2400	2050								
NL					1400		3000	2400	–								6200	
UK								2000		–								34000
NO-N Off.			500															
NO-M Off.				900														
NO-S Off.					800													
DK-W Off.	1400																	
DK-E Off.		400																
DE Off.							25000											
NL Off.									6200									
UK Off.										34000								

Offshore grid

Table 28: Blue numbers from [17], cells marked in red are taken from [16 s. 81], other values are assumptions on future capacities [in white]. Connections from offshore wind farms are assumed to be able to transfer maximum production capacities to land at any time.
*assumed future line expansions.

The transmission matrix used in the 2030 scenario

From, \ To, j	DK-W	DK-E	NO-N	NO-M	NO-S	SE/F	DE	U	NL	UK	NO-N Off.	NO-M Off.	NO-S Off.	DK-W Off.	DK-E Off.	DE Off.	NL Off.	UK Off.
DK-W	–	600*			1950	740	1500							1400				
DK-E	600*	–				1700	550								400			
NO-N			–	1600*		600					500							
NO-M			1600*	–	1300*	600						900						
NO-S	1950			1300*	–	2050	1400*		1400	2000*			800					
SE/F	680	1300	700	500	1850	–	600	600										
DE	950	550			1400*	600	–	9230	3850							25000		
U						600	11250	–	2400	2050								
NL					1400		3000	2400	–								6200	
UK					2000*			2000		–								34000
NO-N Off.			500								Offshore grid							
NO-M Off.				900														
NO-S Off.					800													
DK-W Off.	1400																	
DK-E Off.		400																
DE Off.							25000											
NL Off.									6200									
UK Off.										34000								

Table 29: Blue numbers from [17], cells marked in red are taken from [16 s. 81], other values are assumptions on future capacities [in white]. Connections from offshore wind farms are assumed to be able to transfer maximum production capacities to land at any time.
*assumed future line expansions.

The transmission matrix used in the 2030 Mark 2 scenario:

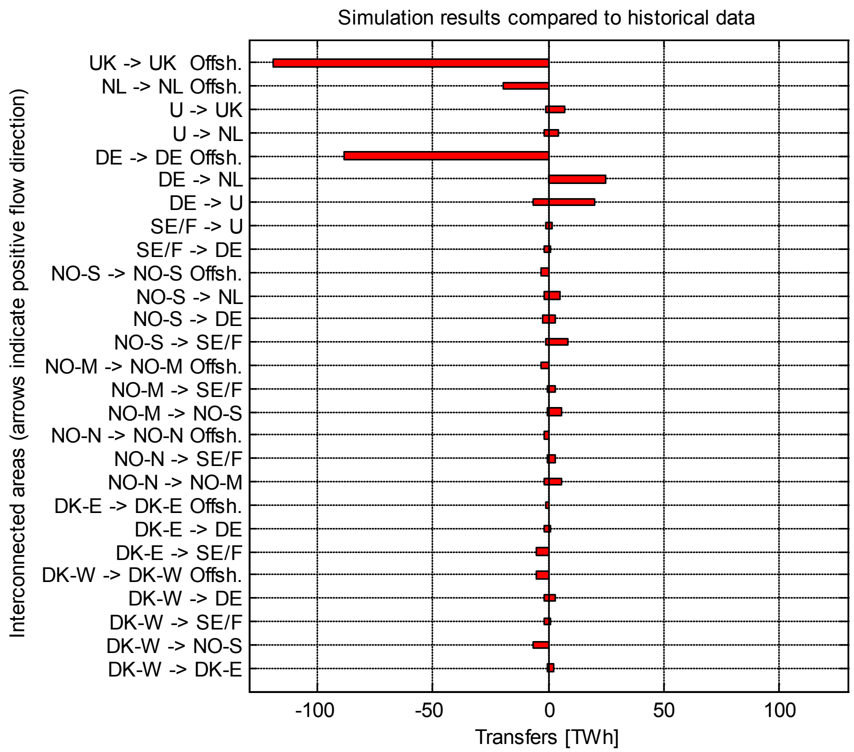
From, \ To, j	DK-W	DK-E	NO-N	NO-M	NO-S	SE/F	DE	U	NL	UK	NO-N Off.	NO-M Off.	NO-S Off.	DK-W Off.	DK-E Off.	DE Off.	NL Off.	UK Off.
DK-W	–	600*			1950	740	1500							2700				
DK-E	600*	–				1700	550								750			
NO-N			–	4600*		800*					1550							
NO-M			4600*	–	4300*	800*						3000						
NO-S	1950			4300*	–	3050*	2000*		2000*	2000*			2500					
SE/F	680	1300	900*	700	2850*	–	600	600										
DE	950	550			2000*	600	–	9230	3850							31000		
U						600	11250	–	2400	2050								
NL					2000*		3000	2400	–								6200	
UK					2000*			2000		–								34000
NO-N Off.			1550								Offshore grid							
NO-M Off.				3000														
NO-S Off.					2500													
DK-W Off.	2700																	
DK-E Off.		750																
DE Off.							31000											
NL Off.									6200									
UK Off.										34000								

Table 30: Blue numbers from [17], cells marked in red are taken from [16 s. 81], other values are assumptions on future capacities [in white]. Connections from offshore wind farms are assumed to be able to transfer maximum production capacities to land at any time.
*assumed future line expansion

Mostly identical to the 2020 matrix. Offshore/onshore connections have been altered to correspond to increased production capacity.

Appendix 5: Simulated energy transfers and mean line loading per scenario

Note: Historical data are not available for these plots. Only simulated data is shown.



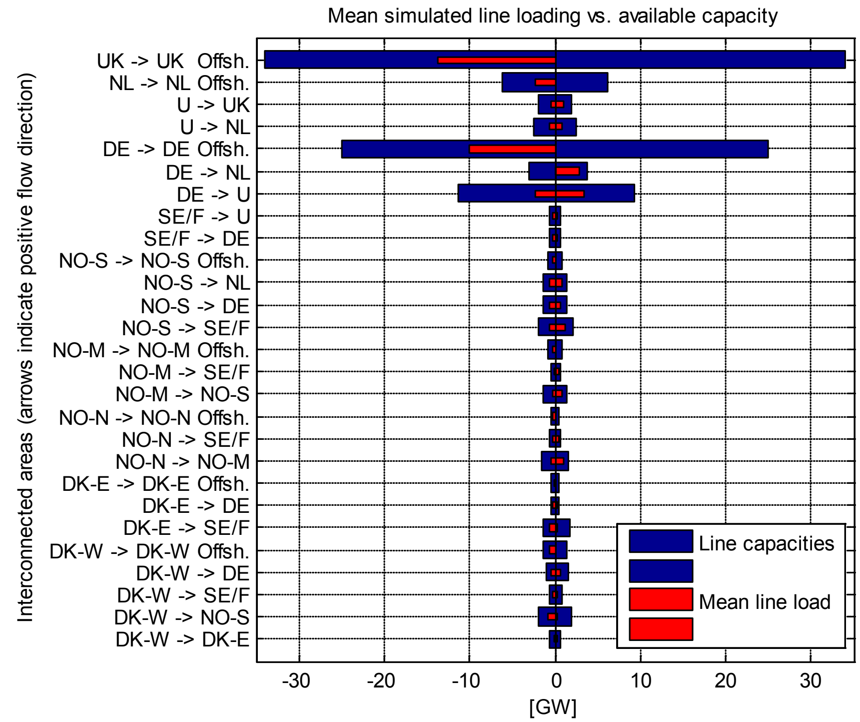


Figure 34: Scenario 2.

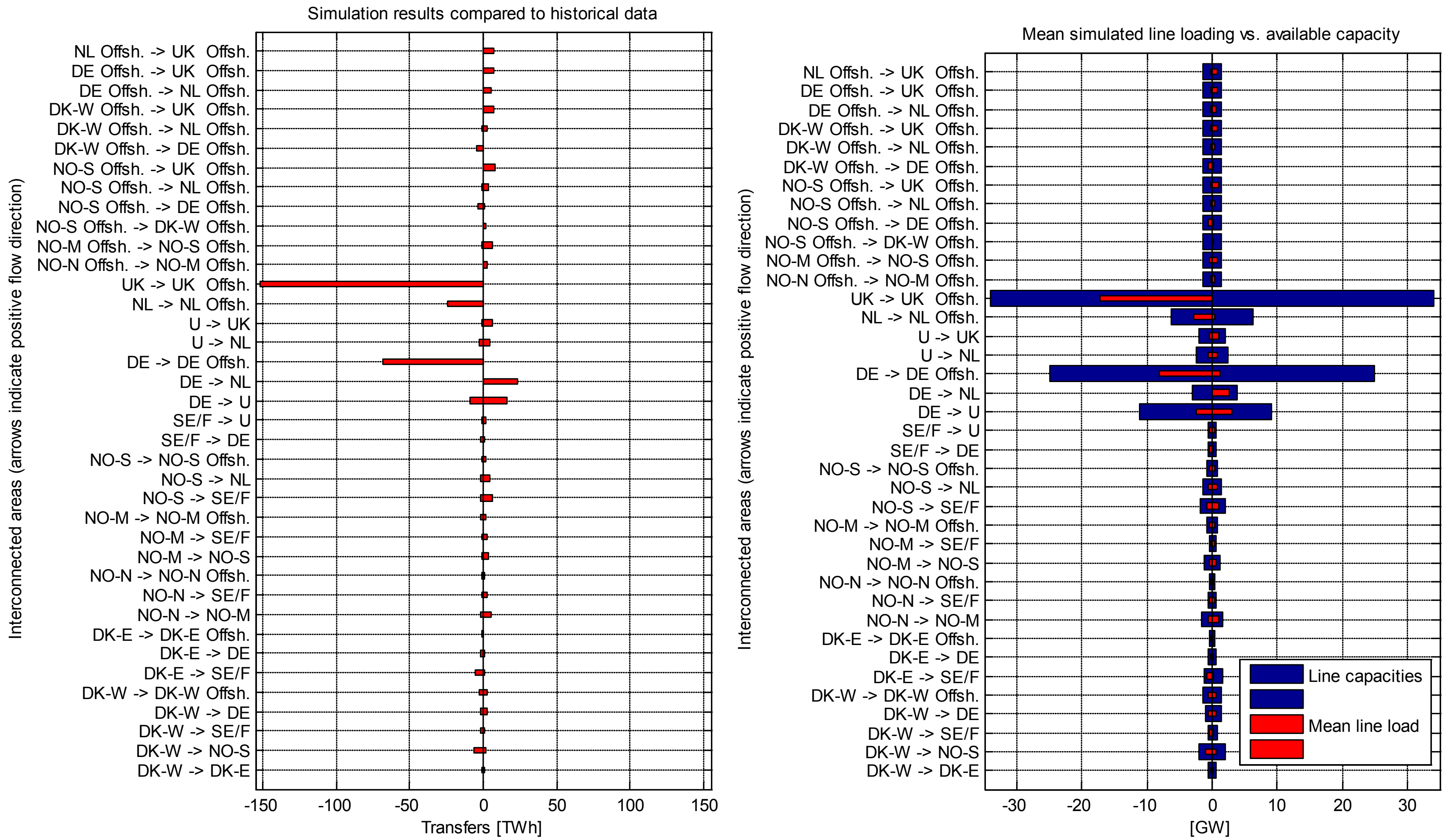


Figure 35: Scenario 3.

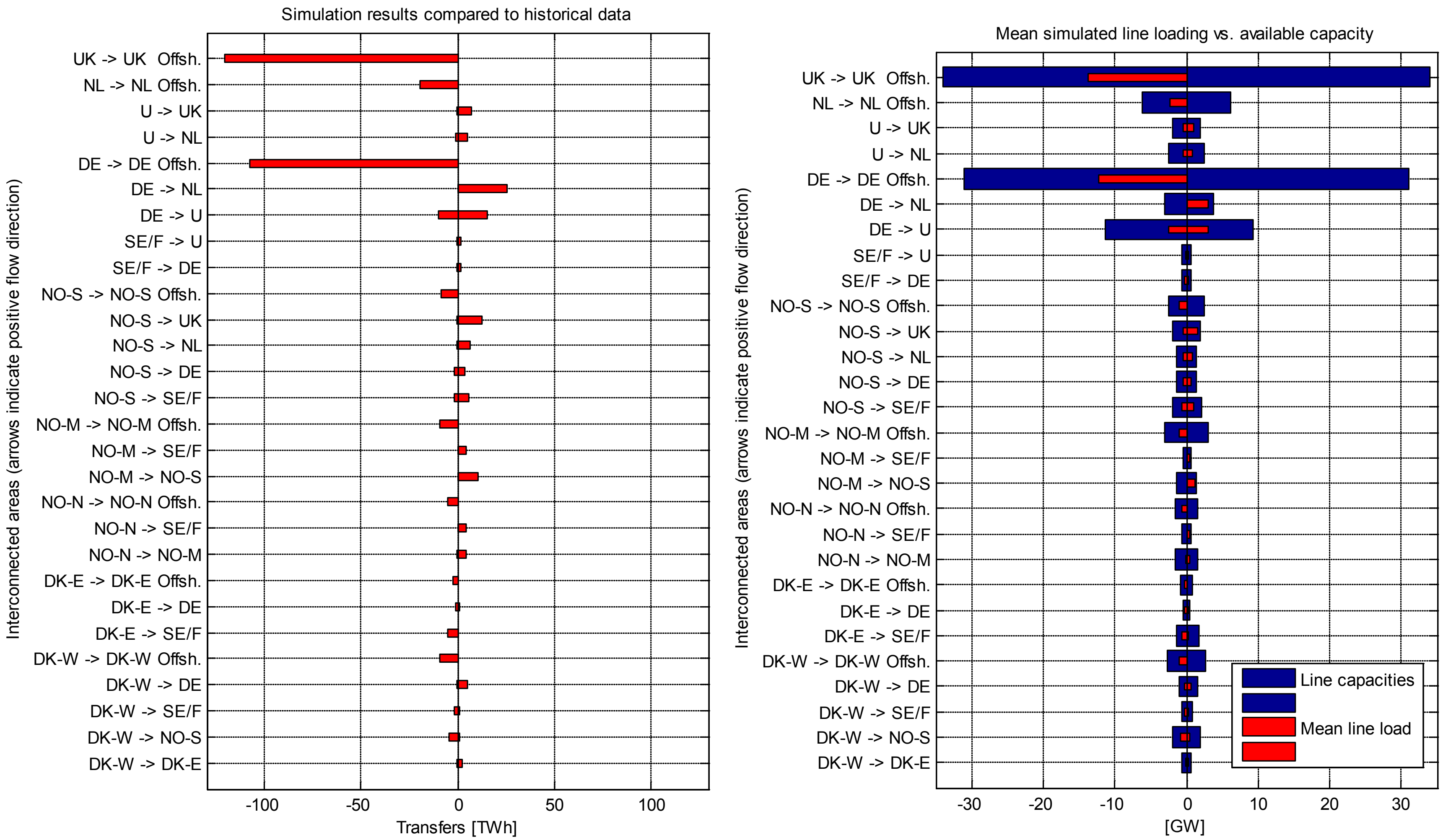


Figure 36: Scenario 4.

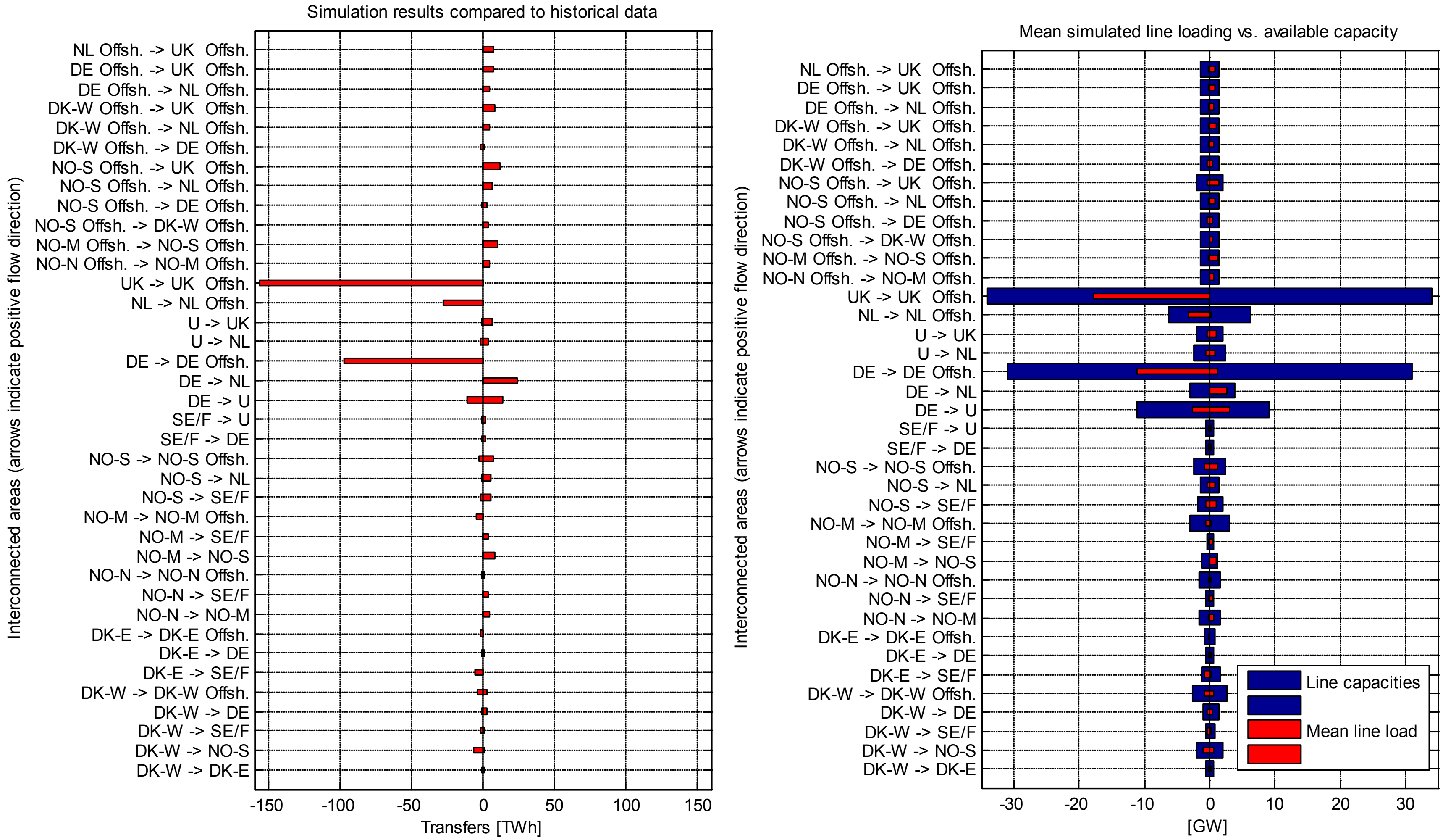
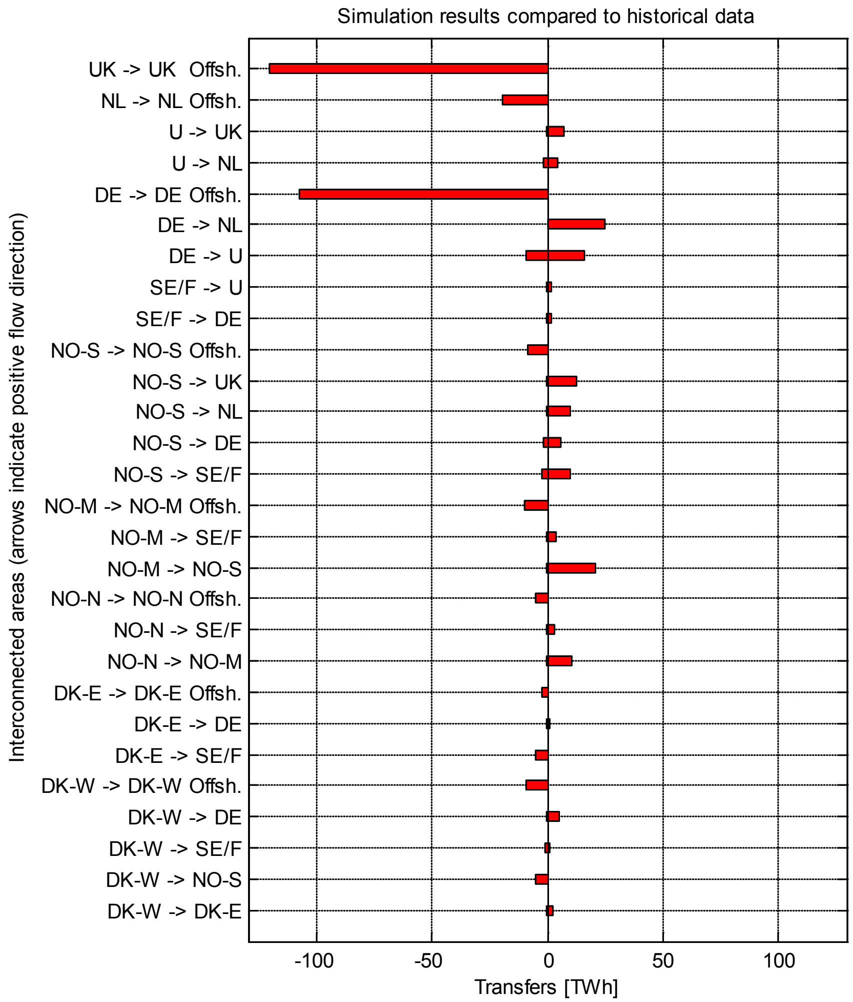


Figure 37: Scenario 5.



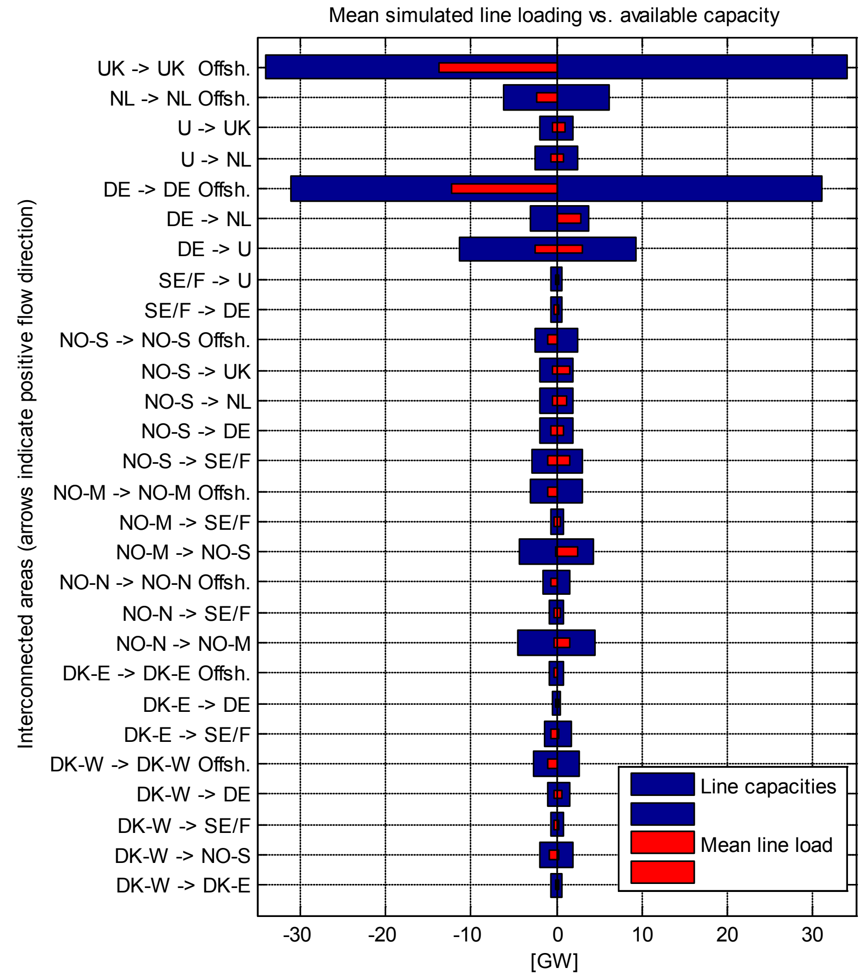
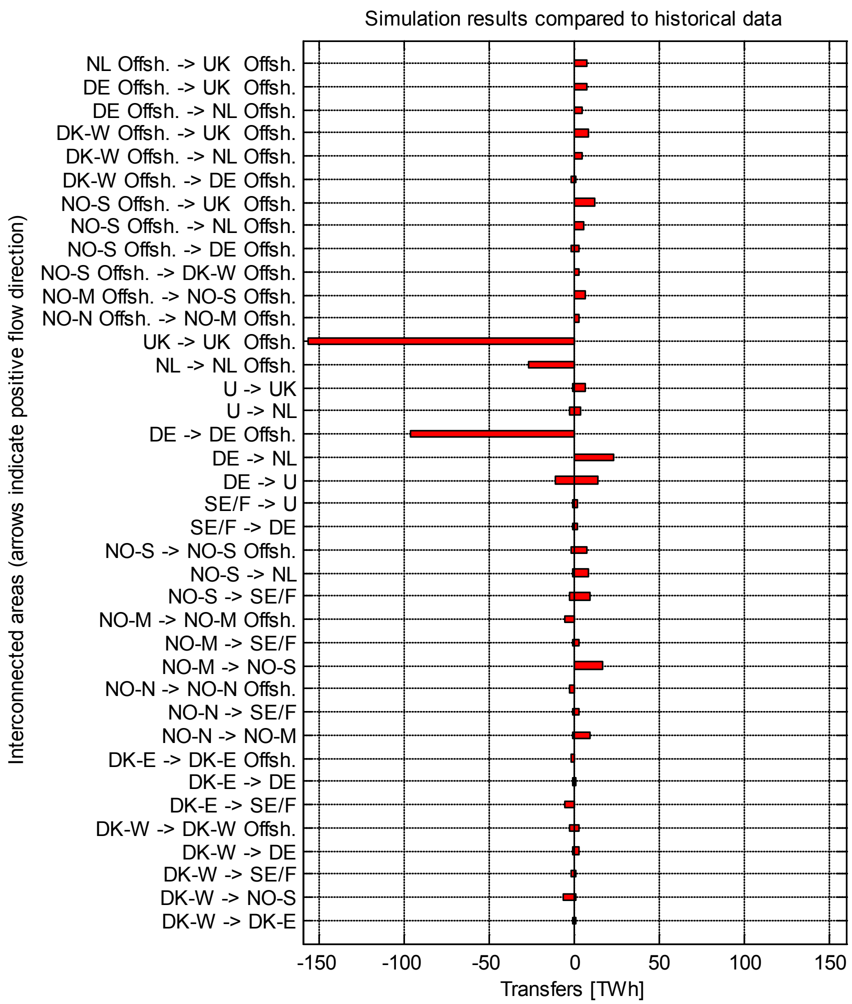


Figure 38: Scenario 6.



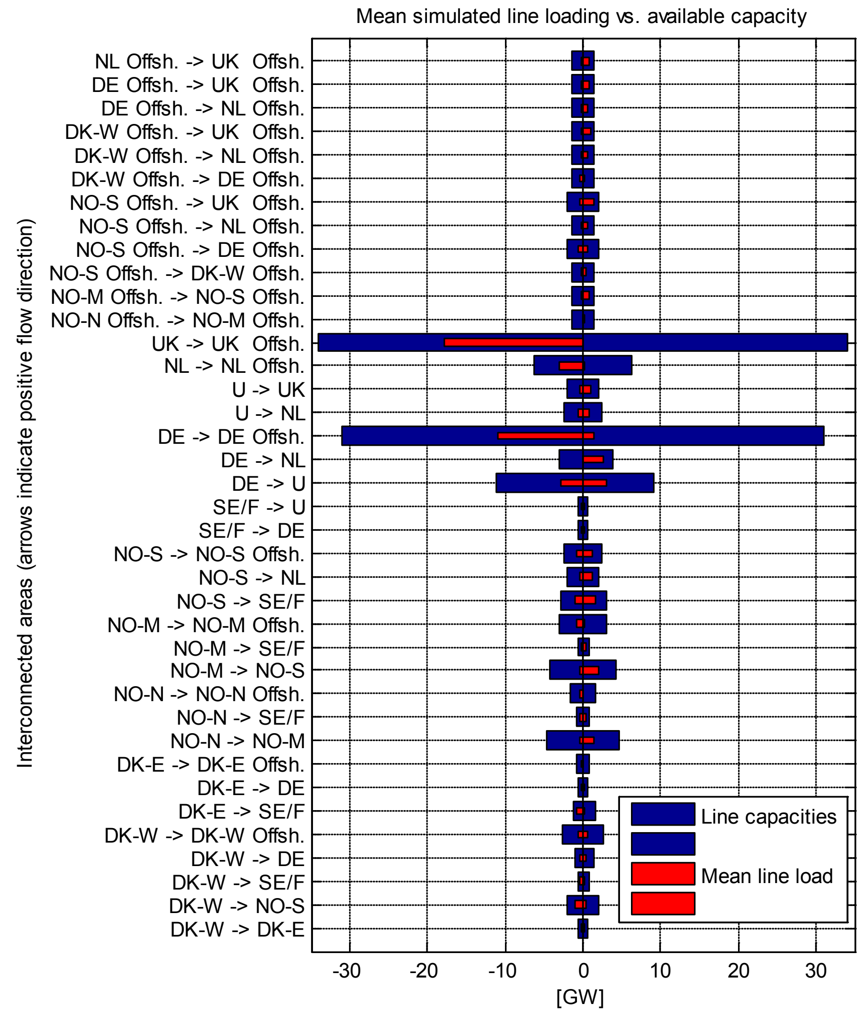


Figure 39: Scenario