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Report

Evaluating North Sea grid alternatives under EU's RES-E targets for 2020

EMPS energy system simulations for Northern Europe

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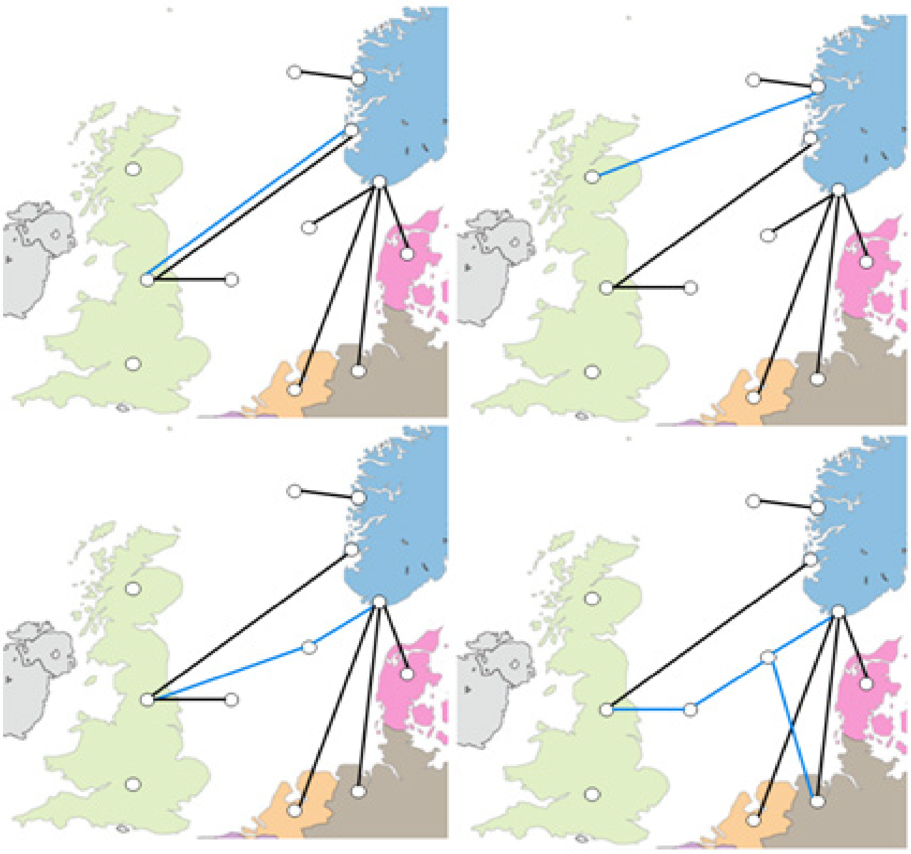

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ABSTRACT

EU's RES-E targets for 2020 and the corresponding national action plans will connect large amounts of non-controllable renewable power generation to the grid, if plans are implemented. This gives increased need for production technologies that easily can balance demand with supply at moderate costs. In this project we have considered alternative power transmission grids in the North Sea, which will connect controllable Norwegian hydropower stronger to the rest of Europe. The power market in northern Europe is simulated for year 2020 using the EMPS model. Renewable power generation is set in accordance with national action plans, while the rest of the system is updated in accordance with forecasts for 2020. We consider different connection points for a direct connection between Norway and GB, cases where the cable is connected to off-shore nodes that include wind-farms and electrification of petroleum installations, and more integrated cases that include a connection to Germany. Each case is evaluated in a cost-benefit analysis. Additional cases show effects of changing assumptions, notably for the amount of wind-power installed in the North Sea, phase-out of German nuclear power and trade the boundary of the simulated system. In the final evaluation, we discuss major finding as well as uncertainties and limitations of our study.

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1 Introduction

1.1 Background for study

Role of North Sea

The European Union Renewable Energy Directive [1] holds binding targets for 20 % renewables contribution to total energy demand by 2020. To reach this target, wind power will play a major factor, also including extensive offshore wind developments in the North Sea. Offshore wind farms are now gradually being planned and built farther from the shore, making the grid connection a more critical factor than earlier. At the same time, the increased need for electricity market integration, and the prospects of using Nordic hydro reservoirs to balance fluctuating wind power at the continent give rise to a growing need for power exchange between countries surrounding the North Sea. Thus, the North Sea will gradually become a more and more important region for the electricity sector. This trend is further emphasised by the plans and possibilities for electrification of North Sea oil and gas rigs, which are commonly supplied by gas turbines located on the platforms. These are expensive to operate and emit significant amounts of CO_2 and NOx. Cable connection between oil/gas platforms and offshore wind farms may thus be an economic and environmentally sound option.

Overall project

The KMB-project “Role of North Sea power transmission in realizing the 2020 renewable energy targets” [2], financed by The Research Council of Norway and by stakeholders in the industry, aims at describing and analyzing a plausible stadium 2020 situation for the role of the North Sea which respect to utilization of offshore wind resources and increased subsea power exchange for realization of the 2020 renewable targets. The base case for 2020 will only constitute point-to-point interconnectors and radial connections of offshore wind farms. Additional cases that include T-connections to offshore wind farms and oil/gas rigs, and partly meshed grids will be analyzed with respect to:

- Socio-economic benefits and costs of offshore grids
- Impacts on power system control and market operation
- Political, regulatory and institutional challenges of investing in T-connections and meshed offshore grid structures

Present study

This study is carried out within WP 2, “Cost-benefit analysis of offshore grid configurations”, which aims to quantify energy system effects (i.e. markets effects) of different offshore grid configurations, mainly for the alternatives described in WP 1 of the project. One main task is to illustrate effects and gains of the increased flexibility given by an integrated grid in the North Sea compared to a case where there are only direct connections. Cost-benefit analyses are carried out for a set of grid-cases, where the benefits are calculated through simulations of the power system in Northern Europe.

1.2 Structure of report

This report is organized as follows. The numerical simulation tool that has been utilized for this study, the EMPS model (no: Samkjøringsmodellen) [3], is described in Chapter 2. This is a fundamental model for the electricity system that maximizes the expected value of total economic surplus. Uncertainty in climate variables (natural variation in e.g. inflow to reservoirs and wind-speeds) is taken into account, and an optimal strategy for utilization of hydropower reservoirs is calculated by stochastic dynamic programming.

Thereafter, the system is simulated for different realizations of climate variables using the strategy for hydropower.

In Chapter 3 we discuss major assumptions and premises for the study, and other inputs to the model. The study-area is the Nordic region, GB, Germany, Netherlands and Belgium. Exchange between these countries and to the outside of the system boundary, e.g. France, is accounted for. An important premise for the study is that the EU actually fulfils the targets for RES-E for 2020 in accordance with the technology-specific national plans that have been submitted. The study is carried out for 2020, and the inputs to the model are updated in accordance with recent forecasts.

Detailed simulation results for a Basecase are presented in Chapter 4. In this case, all North Sea cables are direct connections between different countries, including a 1400 MW cable between Norway and GB. Detailed simulated annual balances are shown for each country, and we show the change compared to IEA's annual balances for 2009. Prices in different countries areas are illustrated, as well as the exchange between different areas. We also evaluate the assumed capacity for thermal power generation, which are based on an ENTSO-E forecast, by comparing investment costs with operational profits.

Chapter 5 show simulation results when we apply 10 alternative off-shore grid configurations in the North Sea in the simulation. For a HVDC cable between Norway and GB we consider direct connections for different connection points in both countries, integration with North Sea nodes (that includes wind-power and electrification of petroleum installations), and an integrated grid that includes a connection to Germany. Additional cases show effects of changing important assumptions. We consider changes for German nuclear power production, the amount of wind-power installed in the North Sea and different assumptions regarding power exchange to countries on the outside of the simulated system. For each cases we prioritize those results that are important for the case under study, such as changes in prices, economic surplus and transmission.

The cost-benefit study is documented in Chapter 6. The applied method for estimating costs of different alternatives are explained, and the calculated costs (total and annualized) for each alternative are reported. The benefits are calculated as the change in total economic surplus for the operation of the system, which are simulated by the EMPS model. For a given grid-alternative in the EMPS model, there may be different degrees of safety and build-in flexibility for the future in the system when considering technological details not represented in EMPS. We carry out cost-benefit analysis for several technology-options, which only differs in terms of investment costs and details in the technological specification, such as the number of DC breakers offshore.

In Chapter 7 we provide conclusions, and important findings are highlighted. At the same time we point out some of the challenges and uncertainties in conducting an energy system study a for large system in a future year. Some of the uncertainties are dealt with in separate scenarios, while many others are only mentioned. We argue that a policy-maker should learn from the major findings in the report, while at the same time fully appreciate the uncertainties involved.

1.3 Acknowledgements

We are most grateful for the financial support from the Research Council of Norway, Statnett SF, NVE, Statkraft SF, Siemens, and Vindkraftforum Sogn og Fjordane.

Stefan Jaehnert developed an EMPS-dataset for 2009 for his PhD thesis [4] within the KMB-project “Balance Management in Multinational Power Markets” [5]. This dataset included the six German areas,

Netherlands and Belgium in addition to the Nordic countries. He made the whole dataset available for us, in addition to a dataset-generating routine he has made. This was a tremendous start for our project and is an excellent example of NTNU and SINTEF working together. In all cases where the described inputs are the same in this report and his PhD thesis, the PhD thesis is the original reference. For our 2020-scenarios, all possible errors are our responsibility.

Steve Völler was a postdoctoral student at NOWITECH during the project. Basically, he made our model for GB. For instance, he divided GB into 3 areas based on congestions in the grid, and allocated demand, thermal power units and hydropower to each of those areas.

Yann Rebours and Frederic Dufourd at EDF R&D have provided important expert advices, and have asked challenging questions during the project. In particular, they argued for an update of the assumed thermal power capacities on basis of a newer ENTSO-E forecast that accounted for the 20/20/20 targets in the EU. The additional scenarios for evaluating the assumed installed capacity were suggested by EDF.

2 EMPS model

2.1 Name, origin and usage

In the following we provide a brief description of the numerical simulation tool that has been utilized for this study. See [3] for a more detailed description of the model. EMPS is the acronym for EFI's Multi-area Power-market Simulator. EFI was the acronym for Elektrisitetsforsyningens ForskningsInstitutt (English: Norwegian Electric Power Research Institute). SINTEF Energy Research was created as a merge between EFI and SINTEF Energy in 1998. The Norwegian name for the model is Samkjøringsmodellen.

The EMPS model has been developed over several decades at EFI and later at SINTEF Energy Research. Two main advantages of the model are the representation of uncertain weather, and the calculation of strategies for the utilization of hydropower reservoirs. The model is used in the planning process for most of the hydropower generation in the Nordic area, and also used by TSOs and governmental agencies in monitoring and planning.

2.2 A fundamental model for system optimization

The EMPS model is an optimization model for a hydro-thermal power system. It is fundamental in the sense that that demand, supply and transmission is modelled with their corresponding characteristics. Formally, the model minimizes the expected system costs in the specified electricity system over a planning period. This is fully equivalent to maximizing total economic surplus when demand can be reduced at a cost specified by the demand function. Since a perfectly functioning market maximizes total economic surplus, there is a theoretical basis for using optimization model such as EMPS for forecasting in liberalized markets, see e.g. [6] for a discussion.

The numerical calculation in the EMPS model is divided into two separate parts. First, the model calculates a strategy for hydropower generation using stochastic dynamic programming (SDP). This is described in the next section. Secondly, the whole system is simulated week by week for each stochastic scenario using linear programming (LP). Figure 2.1 illustrates an equilibrium for one area in one week.

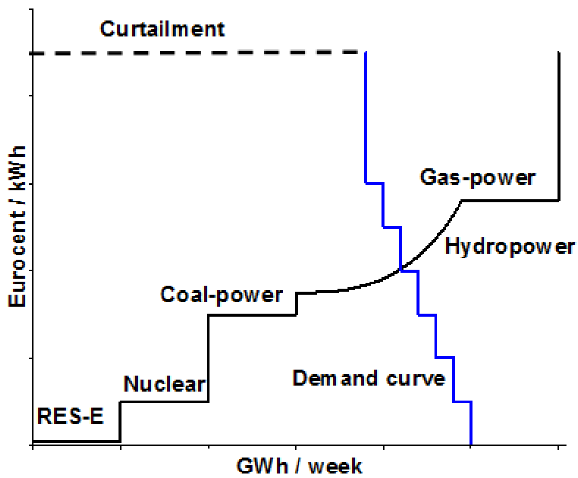


Figure 2.1 Example of market equilibrium

During simulation, total system costs are minimized subject to all constraints of the problem, such as demand, transmission capacities, available generation capacity and the strategies for hydropower generation. The time-resolution can also be finer than week. A week can be divided into aggregated load-periods, or many sequential time-steps.

2.3 Hydropower

Detailed representation
In principle, all reservoirs and generators, including local waterways, efficiencies, and capacities, can be described in the model. For each module that is specified, corresponding hydrological inflow-series must be specified. For Norway, the Norwegian Water Resources and Energy Directorate (NVE) make the hydrological series that are inputs to the model. Each model-user has their own dataset for the model, with different degrees of details and modelling approaches. Many users, such as the large producers, system operators, market consultants and SINTEF Energy Research have a detailed representation of the whole or parts of the Nordic system.

Strategy calculation
The problem that must be solved to calculate strategies for hydropower is stochastic since there are several weather variables in the model, and it is dynamic since reservoir-water can be utilized for electricity generation either in present or future time-steps. The stochastic variables in the model are inflow to reservoirs, inflow directly to station (e.g. run-of-river), outdoor temperatures that affects demand, and RES-E generation variability (wind-power, solar-power). The energy consequence of the different outcomes for climate variables are aggregated to one stochastic variable that goes into the strategy calculation. A variant of stochastic dynamic programming (SDP) called the water-value method is applied.

The strategies are represented by so-called water-values, which represent the marginal value of stored water. Water-values are calculated for a discrete set of reservoir levels, for each week in the planning period and for all areas where hydropower reservoirs are specified. The analysis starts in the final time-step (T), where the expected value (for several outcomes for climate variables) of having additional water available is calculated. This is done for a discrete set of reservoir levels that combined give the water-value table for the final time-step. Now, the same calculation can be carried out for the previous time-step (T-1), taking the water-value for the final time-step (T) as the value of stored water at the end for this time-step (T-1). This backwards induction process continues until water-values have been calculated for all weeks in the planning period.

The end-value function, i.e. the value of water stored at the end of week T, is calibrated such that it would be the water-value for period T+1 if the final year had been repeated many times. An example of a water-value matrix for one area is shown in Figure 2.2. It shows iso-curves for water-values (constant value curves) for different weeks and reservoir levels.

In principle, the water-value for a given reservoir is a function of all the mathematical states of the problem. This includes i.a. reservoir levels in each of the other reservoirs, realized values for each climatic variable (if there is auto-correlation) and the combination of thermal power generation units that is in operation (because of start-up costs). The size of this optimization problem is so large that it is not possible to solve at acceptable computational times using SDP. This challenge is called the curse of dimensionality. The optimization problem for the strategy calculation must therefore be simplified, and in the EMPS model this is handled as follows:

- All reservoirs within an area is aggregated to one equivalent reservoir and station

- Water-values are calculated for each hydropower-area in isolation. A residual demand (demand adjusted for supply from other technologies) is allocated to each area.
- Other state-variables than reservoir levels (e.g. possible auto-correlation in climate variables and the set of thermal power generation that is in operation) is not accounted for when calculating water-values.

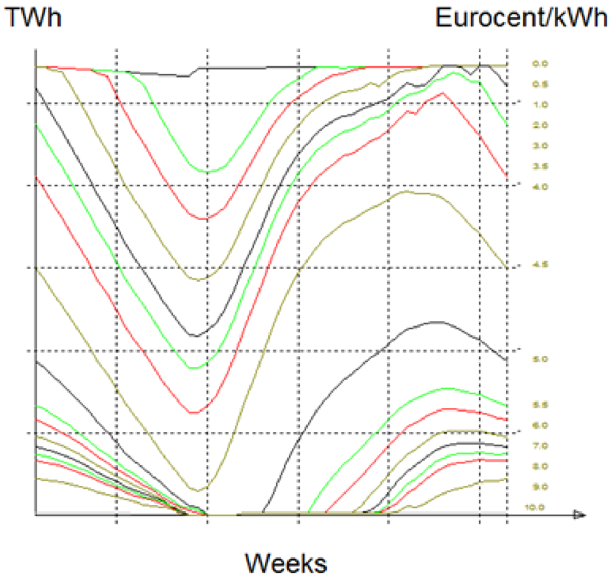


Figure 2.2 Example of water-value matrix

Simulation

When water-values have been calculated, they are treated as marginal costs for hydropower. Now the model carry out a week-by-week simulation, e.g. for week 1 – 52. This is done for each stochastic scenario for the weather variables that are defined in the dataset, e.g. for year 1948 – 2005. The whole interconnected system is simulated, using specified transmission capacities between the different areas. During simulation, demand and all supply are set in accordance with the inputs to the model.

For a given week, there are several simulation/optimization sequences. First, the aggregated "area-optimization" is carried out. In this optimization, the aggregated equivalent hydropower description is applied and total system costs are minimized. The area-optimization can be solved using LP, but sometimes more efficient techniques that utilize the structure of the problem are applied.

Secondly, the solution for hydropower generation for each area from the area-optimization is allocated to the modelled stations for respective areas through a rule-based logic that basically minimizes the danger of reservoir spillage. This part of the simulation is called the "draw-down model". If the area-production is unfeasible because of constraints in the detailed model, the area-optimization for this week is recalculated. The detailed model also calculates an update of efficiencies, which are parametric inputs to the area-optimization. For each week, the area-optimization and draw-down model is solved repeatedly in an iterative procedure until convergence.

Calibration

Because of the mentioned simplifications in water-value calculation, the model must be calibrated by the user on basis of simulation results. There are several calibration factors per area that can be utilized in this process. Calibration factors basically adjust the demand (annual level and within-year profile) and price-flexibility (for demand and other supply-types) that goes into the water-value calculation for each area. The traditional criteria for calibration is to avoid too much spillage in wet years, good within-year utilization of reservoirs, avoid curtailment if possible, and avoid too much systematic within-year price-variation. Some users calibrate the model to imitate statistics for reservoir level handling or other variables. The model can also do an automatic search that improves the calibration step by step in an iterative process, e.g. using total economic surplus as criteria.

2.4 Other model components

Thermal power generation

Thermal power generation includes nuclear power, gas-power, coal-power, oil-power and bio-power. Individual power plants can be modelled. The modelled units are described by marginal costs, capacity, within-year availability and start-up costs (optional). Without the start-up costs, a unit is in operation if marginal costs is less than the price. If start-up costs are specified, a sequential within-week optimization is carried out. This is not a full unit commitment MIP implementation, but a linear approach that allows aggregation of units. The end-state for started capacity in one week is an initial condition for the next-week optimization.

Wind-power and solar-power

Stochastic series specifies wind-power variability for each area, climatic year and time-step. Solar-power is treated in the same manner as wind-power. In practice, energy series for wind- and solar-power are added together before simulation. Inputs may have an hourly resolution, or more aggregated. If the resolution is hour, the model will aggregate hours to the applied time-steps during simulation.

Consumption

There is large flexibility for the specification of demand. For ordinary demand, annual consumption as well as within-year and within-week profiles are typically specified. Several demand types/units can be specified for each area. The demand can respond instantaneous or gradually to prices, or be independent of prices. It is possible to specify a temperature-dependency for demand, and in this case weekly temperatures are stochastic variables in the model. For some industrial demand and dual-fuelled boilers demand is often specified as weekly quantity and a price, which may be different for different weeks.

Transmission

In the standard version of the EMPS model, the connections between different areas are treated as controllable transport channels. This implies that the maximum transmission capacity is utilized between two connected areas unless the price-difference is less than the value of transmission losses. The capacity can be different for different weeks, but are the same for all simulated climate years. Losses can be calculated as a proportion of the transmitted amount or as a quadratic function. It is also possible to attach a specific transmission tariff that comes in addition to the implicit transmission cost through losses. It is possible to carry out detailed power flow, including congestion management based either on system-optimality or a rule-based procedure that reduces the capacities of transmission lines used in the market-clearing process, cf. [7]. This functionality has not been utilized in the present study.

Curtailment

In case inflexible demand exceeds available generation capacity plus import capacity, the market equilibrium is obtained at high system-costs through curtailment, i.e. enforced reduction in demand. In Figure 2.1, this is illustrated by the dotted part of the demand curve.

2.5 Outputs and simulation modes

Outputs

All model-variables can be extracted for each time-step after a simulation has been carried out. In practice, the amount of information that is available is so large that one has to prioritize and/or summarize. Several result-programs have been developed to make this easier. Simulation results of interest can for instance be average values or probability distributions for prices, transmission, economic surplus, reservoir handling, spillage or curtailment.

Simulation-modes

There are two different options for simulation: series and parallel. In a series-simulation, reservoir-levels at the end of week 52 in scenario 1948 will be equal to the reservoir level at the start of week 1 in scenario 1949. In a parallel simulation, the reservoir levels at the start of the first simulated week are the same for each scenario. The former mode is typically utilized when analysing a given future year since this also gives a variation with respect to the reservoir level in the beginning of the year, which is unknown for a given future year. The second mode is typically utilized when forecasting e.g. next year, or when analysing a given historical year. In these cases reservoir-levels at the start of the planning period are in principle known for the year we want to study, and thus the information should be included in the model.

3 Inputs to model for year 2020

3.1 General

Stage 2020

We have simulated the electricity market in Northern Europe for year 2020. The model is updated from the 2009-system [4] to 2020 in accordance with recent forecasts, and on basis of the work that has been carried out in WP1 of the project [8].

National action plans

An important premise for the study is that the 2020-targets for renewable power production in Europe are met in accordance with the technology-specific national implementation plans that have been submitted to the EU [9]. For simulated countries, the plans are summarized in Table 3.1.

Table 3.1 Renewable power generation for 2020 in national action plans submitted to the EU. WP1 estimates for Norway.

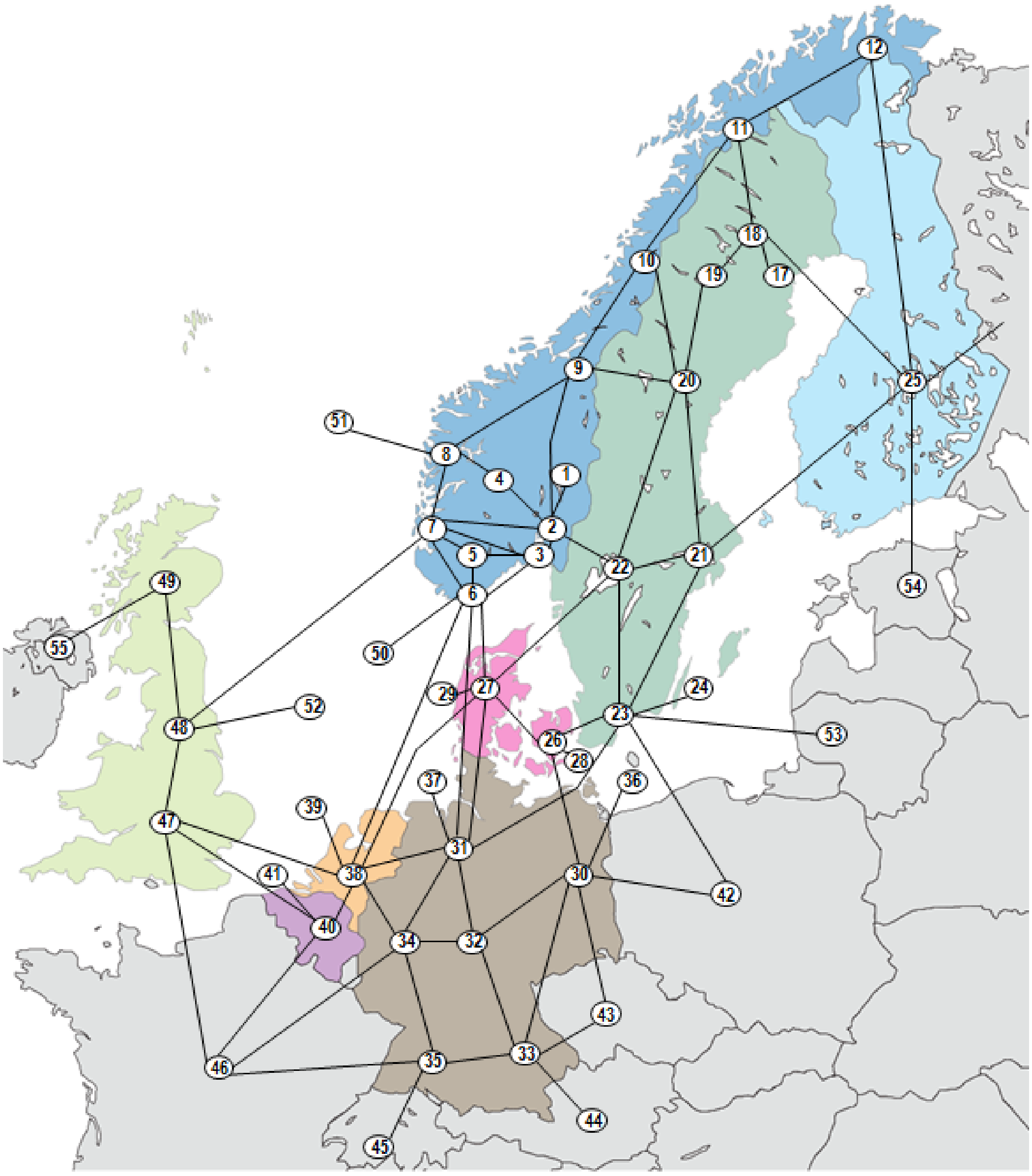
Technology	NO	SW	DA	FI	GE	UK	NL	BE
Hydropower	131,5	68,0		14,4	28,3	6,3	0,7	0,4
Pumped					*8,3*			
Not pumped					*20*			
Wind-power	6	12,5	11,7	6,1	104,4	78,2	32,4	10,5
Onshore	*4*	*12*	*6,4*		*72,7*	*34,1*	*13,4*	
Offshore	*2*	*0,5*	*5,3*		*31,8*	*44,1*	*19,0*	
Solar-power					41,4	2,2		1,1
Biomass		16,7	8,8	12,9	49,5	26,1	16,6	11,0
Others					1,7	4,0		

System boundary and area-division

The system boundary and area-division is illustrated in Figure 3.1. Demand and supply is modelled for the coloured countries. For the grey-coloured countries, only trade is modelled.

North Sea nodes

The study deals with the North Sea transmission grid. In the North Sea we focus on the two North Sea nodes connected to Norway (50 and 51), in addition to the Doggerbank node connected to GB (52). Figure 3.2 shows the WP1 assumptions for these nodes regarding installed wind-power capacity and power consumption because of assumed electrification of petroleum installations. Figure 3.3 summarize simulated consumption and wind-power generation for node 51. The maximum generation of the wind-farm is less than the installed capacity because all turbines normally do not produce at maximum at the same time.



No	Area
1	NOR-GLOMMA
2	NOR-OSTLAND
3	NOR-SOROST
4	NOR-HALLING
5	NOR-TELEMARK
6	NOR-SORLAND
7	NOR-VESTSYD
8	NOR-VESTMIDT
9	NOR-MIDT
10	NOR-HELGE
11	NOR-TROMS
12	NOR-FINNMARK
13	NOR-S-OWP (not shown)
14	NOR-VS-OWP (not shown)
15	NOR-V-OWP (not shown)
16	NOR-M-OWP (not shown)
17	SVER-ON1
18	SVER-ON2
19	SVER-NN1
20	SVER-NN2
21	SVER-MOST
22	SVER-MVEST
23	SVER-SYD
24	SVER-S-OWP
25	FINLAND
26	DANM-OST
27	DANM-VEST
28	DANM-O-OWP
29	DANM-V-OWP
30	TYSK-OST
31	TYSK-NORD
32	TYSK-MIDT
33	TYSK-SYD
34	TYSK-VEST
35	TYSK-SVEST
36	TYSK-O-OWP
37	TYSK-V-OWP
38	NEDERLAND
39	NL-OWP
40	BELGIA
41	BE-OWP
42	POLEN
43	TSJEKKIA
44	OSTERRIKE
45	SVEITS
46	FRANKRIKE
47	GB-SOUT
48	GB-MID
49	GB-NORTH
50	NORDSJO_1
51	NORDSJO_2
52	DOGGERBANK
53	LITHUANIA
54	ESTONIA
55	IRELAND

Figure 3.1 Simulated system and area division

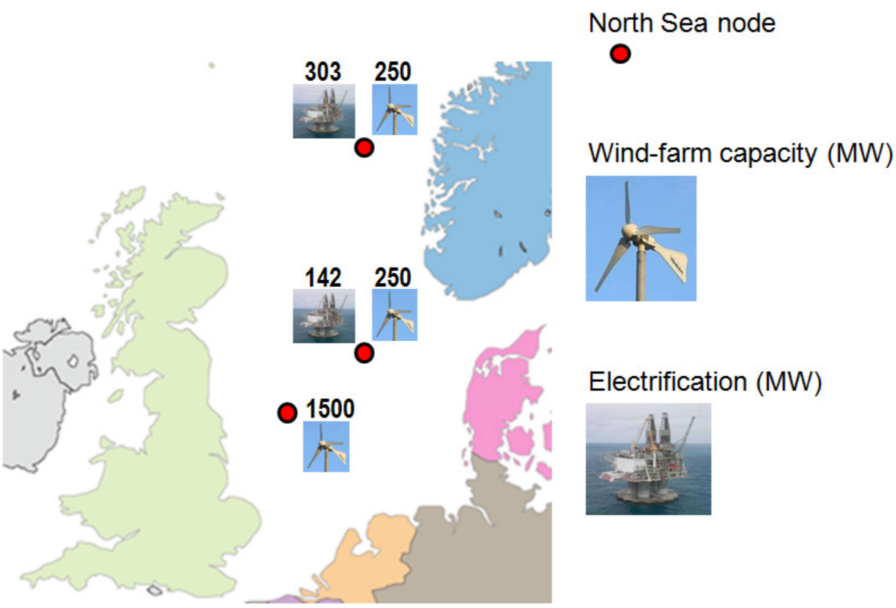


Figure 3.2 North Sea node assumptions

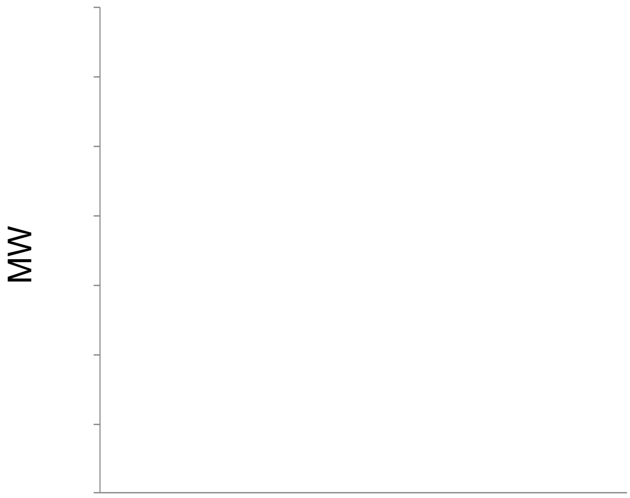


Figure 3.3 Consumption and production for area 51

Climate years and time-steps
The assumed energy system for 2020 is simulated utilizing information of climate variables (inflow, temperatures, wind-speeds and solar radiation) for the period 1948 – 2004 in a 52-week series simulation. Each year is simulated week by week. Within each week, 7 load-periods are ordered in 34 sequential time-steps. In Figure 3.4, the within-week time-steps are illustrated by the demand profile for a German area.

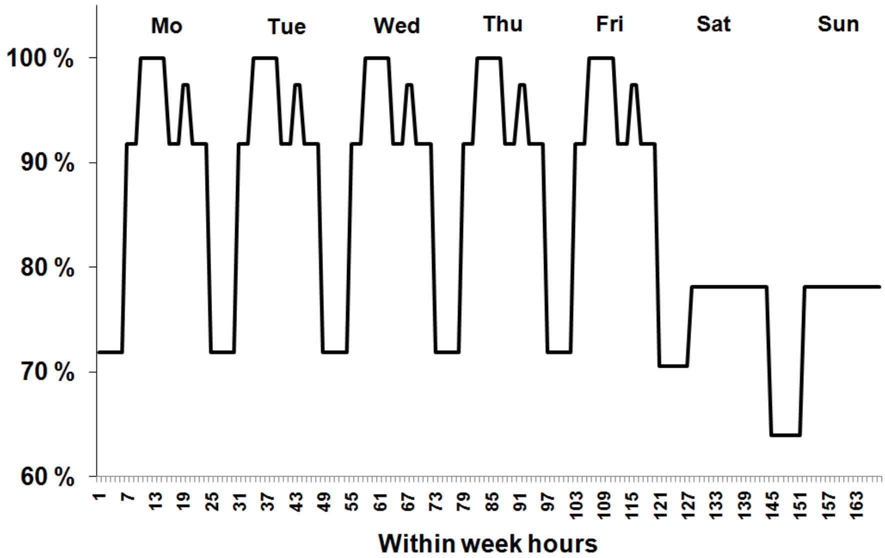


Figure 3.4 Within-week time-steps and relative consumption for area 34

3.2 Wind- and solar-power

The annual amounts of wind- and solar-power per country, as well as the allocation between on-shore and off-shore wind-power, are shown in Table 3.1 and illustrated in Figure 3.5. Within-country capacity-allocation is based mostly on [10], while the variability is based on [11].

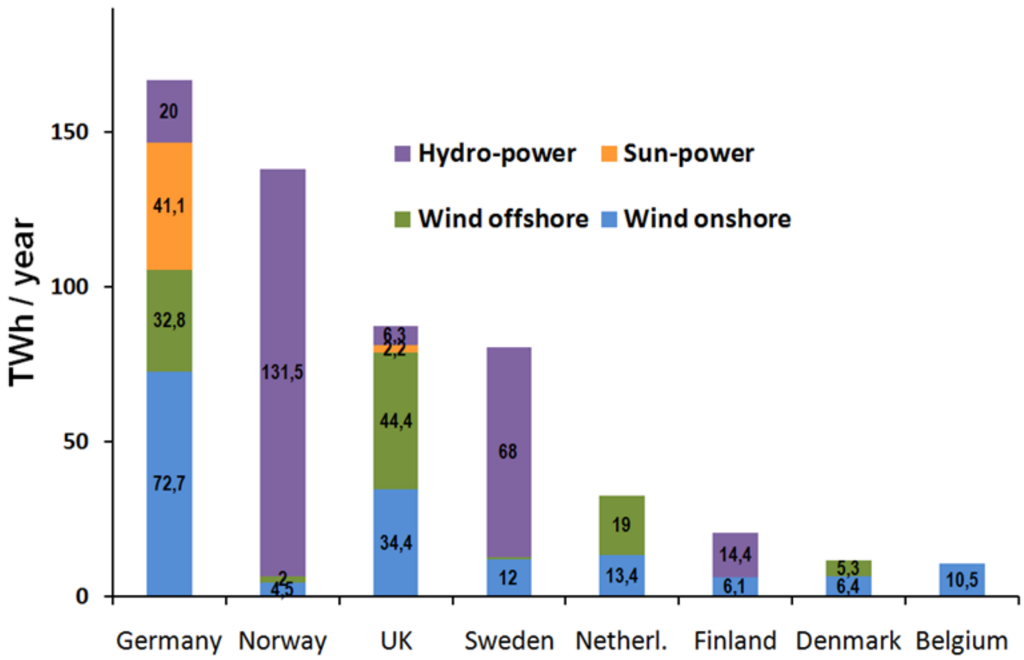


Figure 3.5 **Renewable power generation in 2020 in national action plans submitted to the EU, except biomass. WP1 estimates for Norway**

For GB, the allocation of on-shore wind-power to the northern (49), mid (48) and southern region (47) is 45 %, 15 % and 40 % respectively. For Norway, the on-shore capacity for the southern (6) and mid area (9) is 32 % and 40 % respectively. For Sweden, the allocation for the southern (23) and mid area (22) is 30 % and 35 % respectively. For Denmark, 78 % of the on-shore capacity is allocated to the western region (27). The within-country allocation for Germany is shown in Table 3.2. For solar-power, capacity is allocated proportionally to the maximum consumption load for different areas [4].

Table 3.2 Within-area allocation for Germany [4]

No	Area	Hydro [4]	Solar [4]	Wind [10]
30	OST	15 %	14,2 %	31,5 %
31	NORD	0%	9,3 %	18,7 %
32	MIDT	5%	11,3 %	7,7 %
33	SYD	40%	11,6 %	1,0 %
34	VEST	15%	37,4 %	17,6 %
35	SYDVEST	25%	16,3 %	1,6 %
36	O-OWP			3,8 %
37	V-OWP			18,0 %

The EMPS model aggregates hourly inputs into the within-week sequential time-steps that are simulated for 1948 – 2004. As an example, the within-day and within-year variability for wind-power at Doggerbank is shown in Figure 3.6 - Figure 3.7, while the variability for solar-power in Western Germany is shown in Figure 3.8 - Figure 3.9.

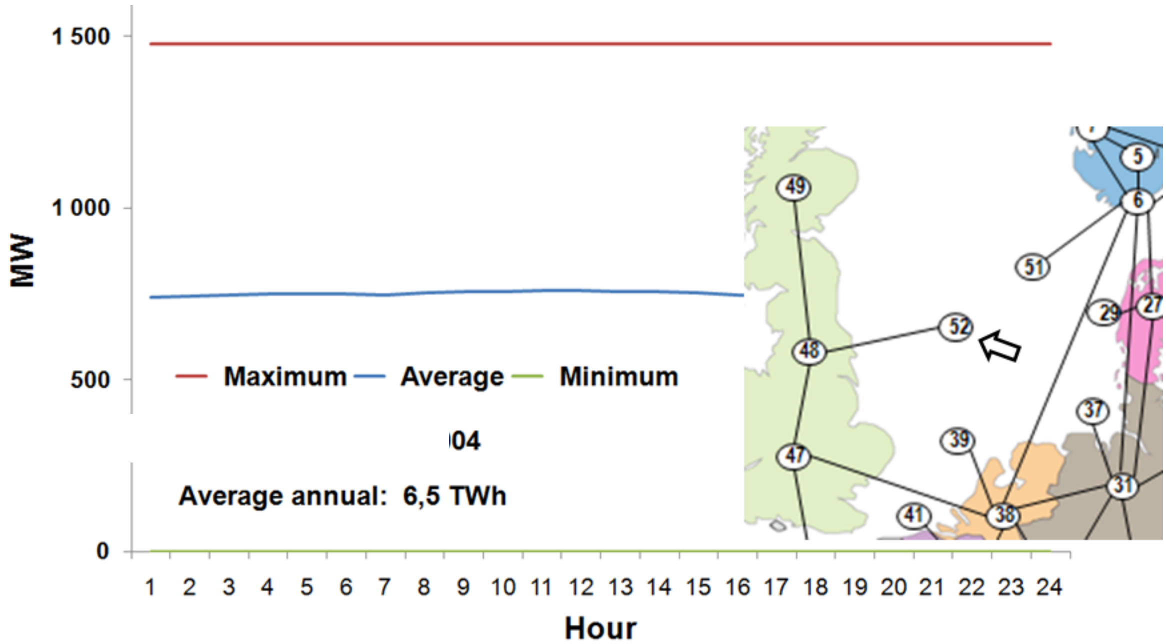


Figure 3.6 Within-day variability for wind-power production at Doggerbank

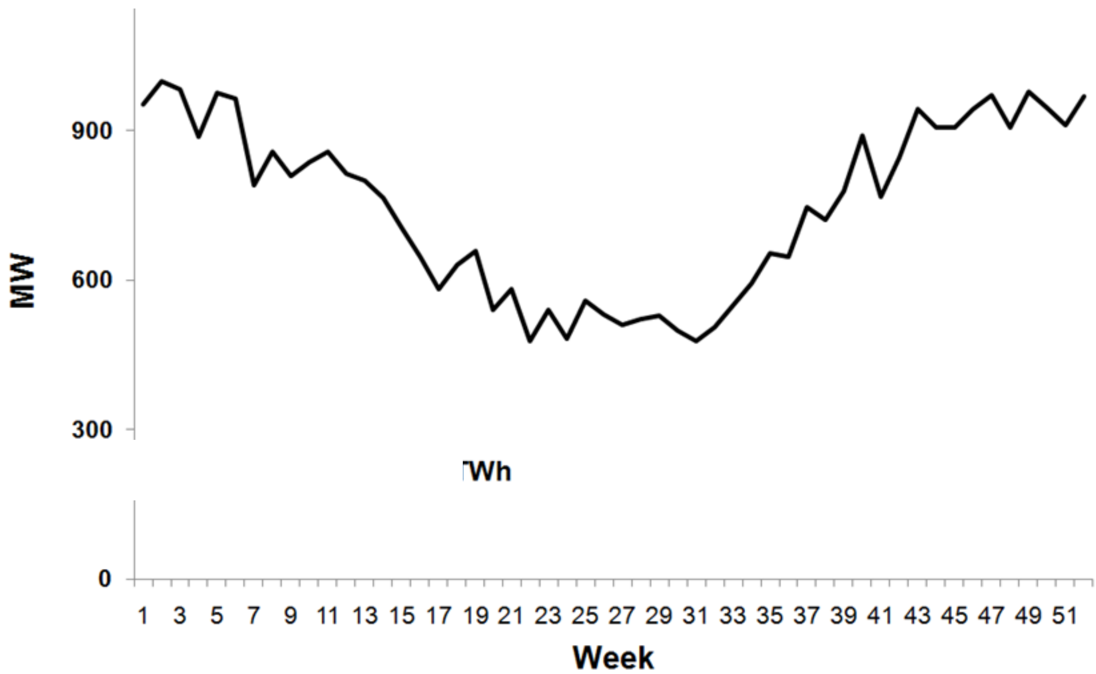


Figure 3.7 Within-year weekly average profile for wind-power at Doggerbank

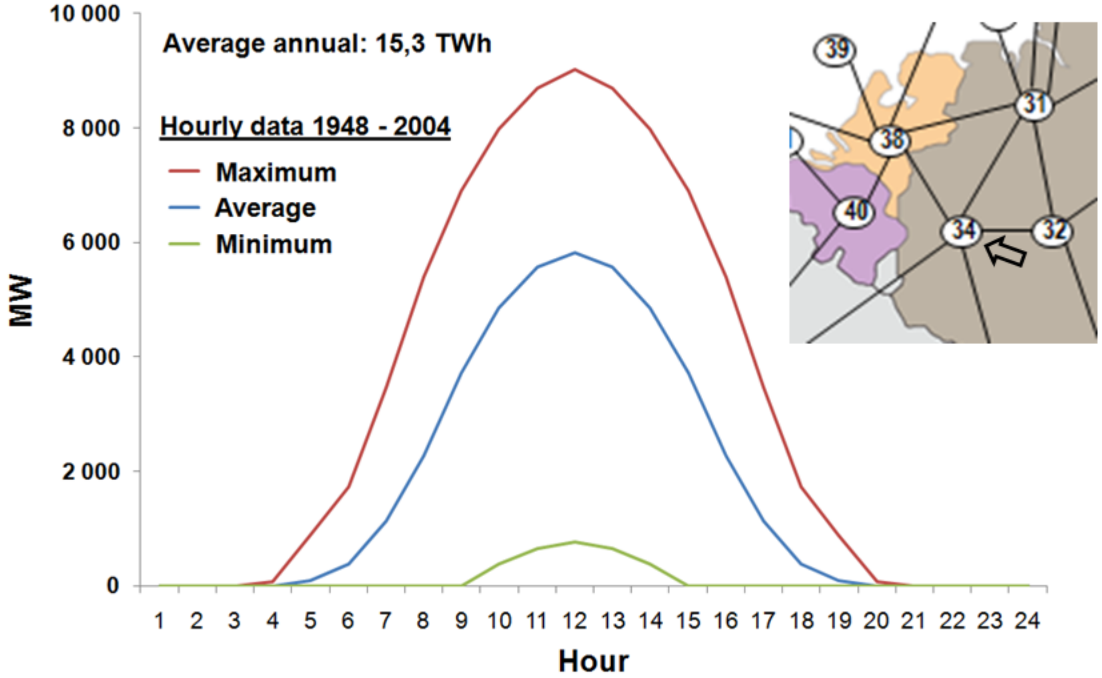


Figure 3.8 Within-day variability for solar-power in Western Germany

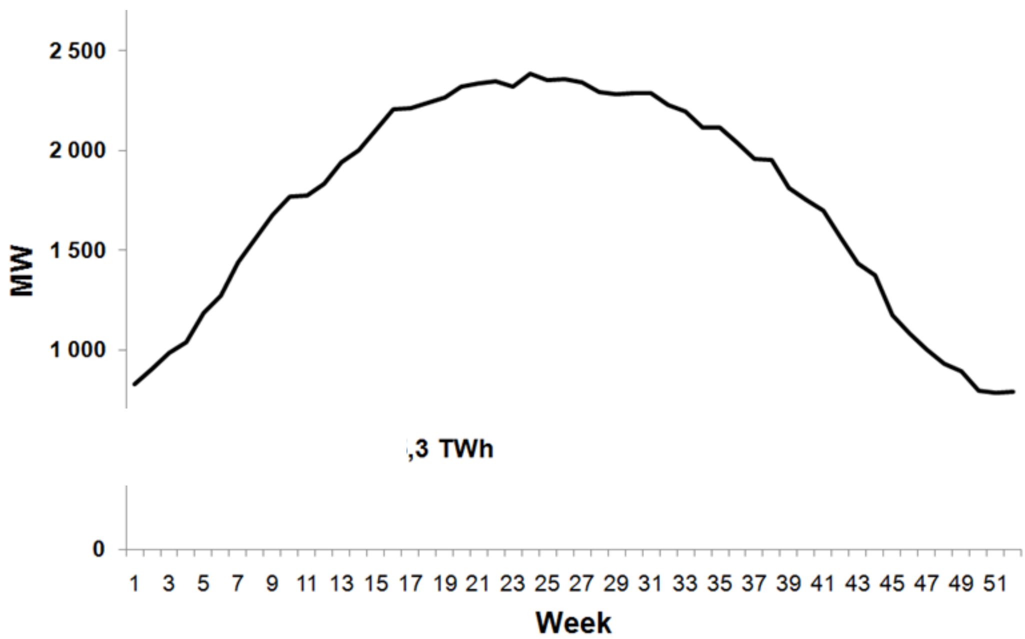


Figure 3.9 Within-year weekly average profile for solar-power in Western Germany

3.3 Hydropower

Norway

WP1 basecase-forecast for annual hydropower production in Norway is 131,5 TWh, which is approximately a 10 TWh increase compared to the average production in the current system. We assumed that the increase in hydropower comes from small-scale hydropower. It is expected that this technology will be competitive in the common Norwegian-Swedish market for green certificates that started in 2012. In total, that system will roughly give 26 TWh extra renewable power in Norway and Sweden by 2020. In SINTEF's dataset for the detailed hydropower there is a default module for small scale hydropower in each area, and we used this to scale up total production proportionally for each area.

While the target for Norway was 131,5 TWh, the simulated average value is 133 TWh. The reason for this is that the simulated value is affected by model calibration and other assumptions. The extra hydropower was therefore adjusted in an iterative process, and we decided that 133 TWh was sufficiently close to the target.

Hydropower was calibrated in accordance with the traditional criteria. The most important criteria are:

- Avoid curtailment because of energy shortage
- Avoid excessive spillage from reservoirs
- Utilized reservoirs (sufficient draw-down and filling profile over a year)

These criteria are consistent with the maximization of total economic surplus, but the functionality that searches for the best economic reservoir handling took too long computational time for this dataset, which also includes start-up optimization for thermal power generation units.

In areas where hydropower is only a small fraction of the total supply, model calibration of reservoir handling is not important. However, for the hydro dominated Nordic area, especially for Norway, reservoir handling is of major importance for simulation results. Appendix A shows the simulated reservoir handling for Nordic areas.

For hydropower we have not considered specific capacity-investments (MW) up to 2020. There are several reasons why we have not prioritized this:

- The installed capacity for Norwegian hydropower already is large compared to the typical consumption, so the exchange is typically limited by the capacity of transmission lines.
- In simulations, we do not include a detailed power-flow analysis. The transmission capacity within Norway is therefore fully controllable. This reduces the need for capacity-investments.
- We have focused only on the spot market, not the balancing market.

Other countries

The forecasted annual hydropower production for other countries is shown in Table 3.1. For Sweden and Finland we added small-scale hydropower to reach the targets. For UK, all hydropower is allocated to the northern region (49) even though there is some (~0.5 TWh) hydropower further south. For Germany, the allocation of hydropower to different areas is shown in Table 3.2. The pumped storage is mostly used for the balancing market and not included in our simulations.

3.4 Thermal power generation

Fuel-types
Thermal power generation includes nuclear power, bio-based power generation and the fossil-fuel power plants, which are coal-power (hard coal and lignite), gas-power and oil-power.

Database for 2008
SINTEF's database for existing thermal power plants in 2008 was established within the KMB-project “Balance Management in Multinational Power Markets”. It includes capacities, efficiencies, fuel-types, and several cost types among other things. For GB, power-plant information was provided by [14] on basis of Digest of UK energy statistics (DUKES) for 2008 and National Electricity Transmission System Seven Year Statement (NETS SYS 2010).

Forecast 2020
Thermal power generation capacities for 2020 are based on the 2020-forecast in ENTSO-E’s Scenario Outlook & Adequacy Forecast (SO&AF) 2011- 2025 [15], cf. Table 3.3. Figure 3.10 shows the difference between the 2020-forecast and our database for existing units in 2008. For most countries we added the mixed/unidentified capacity to the hard coal capacity. Consequences of recent changes in attitude towards nuclear power, especially in Germany, are analysed separately.

Retirement
In cases where the forecasted 2020-capacity for a given technology and country is less than the capacity in our 2008-database, the oldest units were removed from the dataset. For instance, almost 6 GW of the hard-coal power plant capacity is retired for GB. In the detailed power-plant list, so many of the oldest units were picked out that the needed retirement was obtained, leading to retirement for all units built before 1969 and for some units built in 1969.

New capacity
In cases where the forecasted 2020-capacity for a given technology and country is larger than the capacity in our 2008-database, the additional capacity is assume to be new efficient units. For each technology, the marginal cost for new capacity in 2020 is set to the lowest marginal cost of all the units of that type in the 2008-database.

Aggregation
To avoid too long computational time, units were aggregated into categories within each area. The modelling-approach for start-stop decisions in the EMPS-model allows such aggregation. The aggregated categories are based on the fuel-type. Units that have heat-delivery obligation are divided into separate categories for each fuel type. In addition, turbines (gas or oil) are separate categories because of higher marginal costs. For each of these combinations, there are separate categories for existing capacity in 2008 and for new capacity. In total, the aggregation process reduced the number of units to approximately 1/5. As an example, the aggregation of coal-power plants in northern Germany without heat-delivery obligations is illustrated in Figure 3.11.

The aggregation process reduces the spread in marginal costs and prices. However, differences in marginal costs between different areas, e.g. because of a different aging-structure of power plants, are maintained since the aggregation is carried out per area.

Table 3.3 Forecasted 2020-capacity (MW) for thermal power generation

	Denmark	Sweden	Finland	Belgium	Netherlands	Germany	UK
Hard coal	700	100	2900	200	7500	26000	17800
Lignite						14000	
Bio	2805	2914	2920	2470	2892	9062	4210
Gas	2000	900	2300	10300	21800	18000	32300
Nuclear		10100	5900	4120	500	18800	11200
Oil	600	2400	1200		200	1000	
Mixed/unid.	1900	500	2200		1200	5000	1400
Total	8005	16914	17420	17090	34092	91862	66910

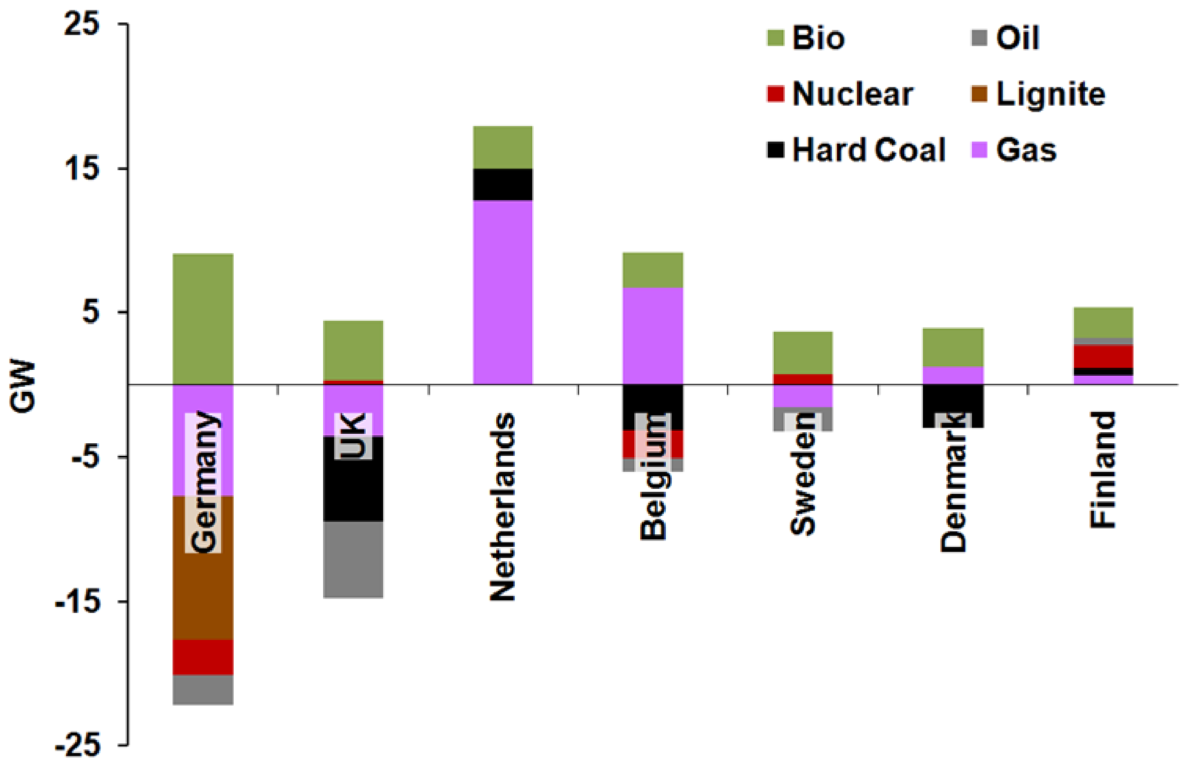


Figure 3.10 Capacity change from 2008 (our database) to 2020 (ENTSO-E forecast)

<u>Heat-deliveries</u>
Some power plants have heat-delivery commitments. When producing this heat, some power is generated too. The production costs for this power is therefore negligible. In the model, this production is represented separately using 1 Eurocent/kWh marginal cost and no start-up costs. However, the produced amount of electricity can be increased at a higher marginal cost. The share of the full electric capacity that is produced at low costs ranges from 69 % in week 52 to 3 % in week 30.

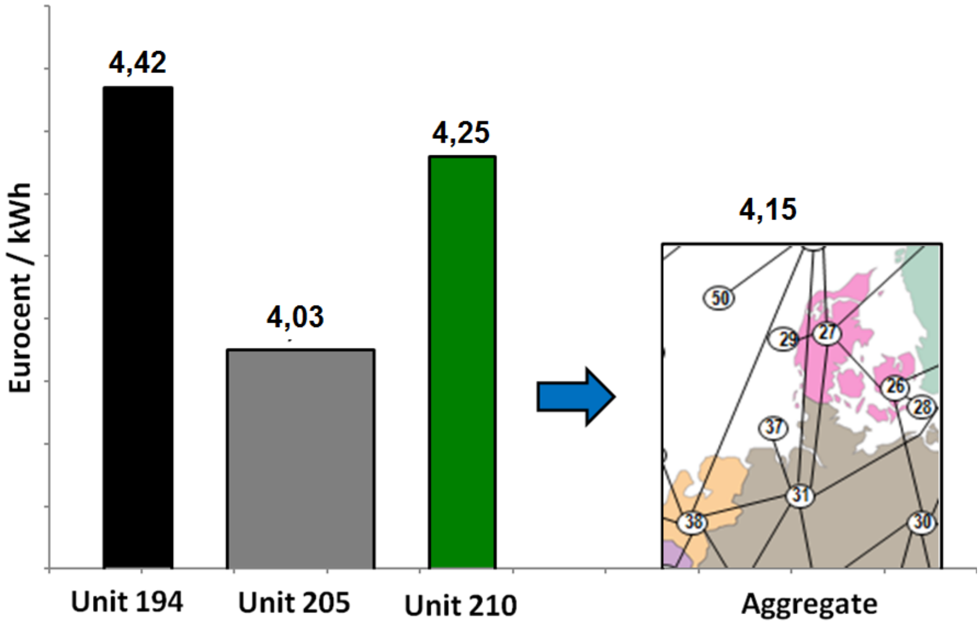


Figure 3.11 Aggregation of existing coal-power capacities in North-Germany (area 31) No heat delivery

Exogenous prices

Marginal costs for thermal power generation are affected by fossil-fuel prices, CO_2-permit costs and possible subsidies for biomass-based power generation. These prices are based on the reference scenario of the PRIMES model that is reported in the impact assessment accompanying the document "A Roadmap for moving to a competitive low carbon economy in 2050" [16]. This reference scenario takes present policy into account, such as the 2020 targets for RES-E. Forecasted prices are shown in Table 3.4.

Table 3.4 Forecasted 2020-prices

Commodity	Forecast [16]	Unit	Converted	Unit
Coal	25	2008$/BOE [1]	9,9	2010€/MWh th
Gas	60	2008$/BOE	23,7	2010€/MWh th
Oil	80	2008$/BOE	31,6	2010€/MWh th
CO_2	16,5	€/ton		
RES-E value	49,5	€/MWh el [2]		

We have interpreted the coal price in [16] as the price of hard coal. For lignite we assumed that the price is 80 % of the hard coal price. For biomass energy we utilized a 31,7 €/MWh th forecast provided by Energianalyse.

[1] BOE is barrel of oil equivalent. The energy content is approximate 1,7 MWh, but various grades of oil have slightly different heating values.

[2] In our simulation, we have interpreted the RES-E value as a €/MWh support scheme for power production based on biomass.

<u>CO_2-content in fuel</u>
The CO_2-emissions from combustion of fossil fuel varies for different fuel types. Table 3.5 shows the applied fuel types, and the corresponding CO_2 emissions in kilogramme per MWh heat. Emission per MWh generated electricity will however be higher since the efficiency of power plants is less than 100 %.

In Table 3.5 the CO_2-content of biomass is set to zero. Actually, there are considerable CO_2-emissions from combustion of biomass too. Still, the emission coefficient is set to zero since emissions from biomass is not included in the permit system for CO_2. The rationale for this is that the biomass absorbed CO_2 from the atmosphere during the growth, and this CO_2 will be released to the atmosphere again in the long run even if it is not used for energy purposes.

Table 3.5 CO_2-content in fuel measured in kilogramme per MWh th

Fuel type	CO_2 content
Hard coal	370
Lignite	500
Gas	200
Oil	300 / 350
Biomass	0
Atomic fuel	0

<u>Marginal costs example</u>
In the following we calculate marginal costs for a moderate efficient (40%) coal-power plant, and an efficient (60%) gas-power plant. These calculations show that coal-power in general will be less expensive than gas-power when we apply the forecasted prices in [16].

$$mc_{40\%}^{coal}\left(\text{€/MWh el}\right)=\frac{\overbrace{9{,}9\left(\text{€/MWh th}\right)}^{\text{coal price}}+\overbrace{16{,}5\left(\text{€/ton}\right)}^{\text{permit price}}\cdot\overbrace{0{,}37(\text{ton/MWh th})}^{\text{emission coefficient}}}{\underbrace{0{,}4\left(\text{MWh el / MWh th}\right)}_{\text{efficiency}}}=40{,}0 \tag{3.1}$$

$$mc_{60\%}^{gas}\left(\text{€/MWh el}\right)=\frac{23{,}7\left(\text{€/MWh th}\right)+16{,}5\left(\text{€/ton}\right)\cdot 0{,}2(\text{ton/MWh th})}{0{,}6\left(\text{MWh el / MWh th}\right)}=45{,}0 \tag{3.2}$$

3.5 Consumption

The RES-E action plans [9] are used to forecast 2020-consumption, cf. Table 3.6. The total growth in the period 2009 – 2020 is also indicated using 2009-numbers from [17].

For Norway, NVE provided the 2020-forecast. The Norwegian consumption includes electrification of petroleum installations in the North Sea, cf. Figure 3.2. For Sweden, Svenska Kraftnät provided the consumption figure for 2009.

The allocation of demand to within-country areas and consumption profiles are based on SINTEF's database for the Nordic area. For other countries, profiles are mostly based on hourly consumption data from TSOs [4], [14]. The regional split for Germany is based on Regionenmodell 2013, which is a model developed by the TSOs. Temperature correction of demand is carried out for the consumption in Norway and Finland. In the Nordic region some consumption respond to prices (dual-fuelled boilers and some industry), while no price-elasticity for demand is modelled for other countries.

Table 3.6 Annual consumption forecast for 2020, including network losses

Country	TWh / year	2009-2020
Germany	562	+ 4 %
GB	377	+ 18 %
Sweden	154	+ 15 %
Norway	140	+ 12 %
Netherlands	136	+ 20 %
Finland	102	+ 25 %
Belgium	102	+ 20 %
Denmark	38	+ 8 %

3.6 Transmission capacities

The updated 2020-transmission capacities between countries are based on several sources.

- For the Nordic area, SINTEF's database for transmission capacities was updated to 2020 in [18].
- For Norway it is assumed that several planned grid-development projects are finalized, such as Ørskog – Fardal, Sima – Samnanger, and connecting lines.
- An overview of existing and planned off-shore HVDC cables in Europe are given in [8].
- Existing country-to-country net transfer capacities are published by ENTSO-E [19].
- ENTSO-E has published an overview of new projects in different phases (planned, under construction etc).
- A separate study was carried out [14] to split GB such that important congestion is accounted for.
- For within-country transmission in Germany, capacities are updated in accordance with the Dena II study [4].

Based on an assessment of this information, transmission capacities were updated to 2020. The finalized capacity matrix for transmission between countries is shown in Table 3.7.

3.7 System boundary exchange

For countries on the outside of the simulated system (nodes in grey- coloured countries in Figure 3.1, i.e. the countries labelled "exogenous countries" in Table 3.7) , the price is set to the marginal costs for new gas-power (44 Euro/MWh) at daytime, and to the marginal costs for average-efficient coal-power (39 Euro/MWh) at night and week-end. For France, the price at night and in week-ends is set to the low marginal cost for nuclear power. For Finland we assume a fixed 10,5 TWh import from Russia.

Table 3.7 Country-to-country transmission capacities (MW)

	Endogenous countries								Exogenous countries							
To\From	NO	SW	DE	FI	GE	GB	NL	BE	IR	FR	SWZ	AU	CZ	PO	LI	ES
NO	-	5100	1550	150	1400	1400	1400									
SWE	5100	-	2440	2450	600									100	1000	
DE	1550	1980	-		2035		700									
FI	100	2850		-												600
GE	1400	600	2600		-		6500			2700	4400	2000	2300	1200		
GB	1400					-	1290	1000	500	3000						
NL	1400		700		6100	1290	-	2400								
BE						1000	2400	-		996						
IR						1000										
FR					2700	3000		996								
SWZ					2060											
AU					2200											
CZ					800											
PO		600			1200											
LI		1000														
ES				650												

4 Simulation results for Case A1 (Basecase)

4.1 North Sea grid

In the following we report simulation results for the case described in Chapter 3. We refer to this case as Basecase, and give a more extensive report of results than for the other cases. In the Basecase, there are only direct connections in the North Sea, cf. Figure 4.1.

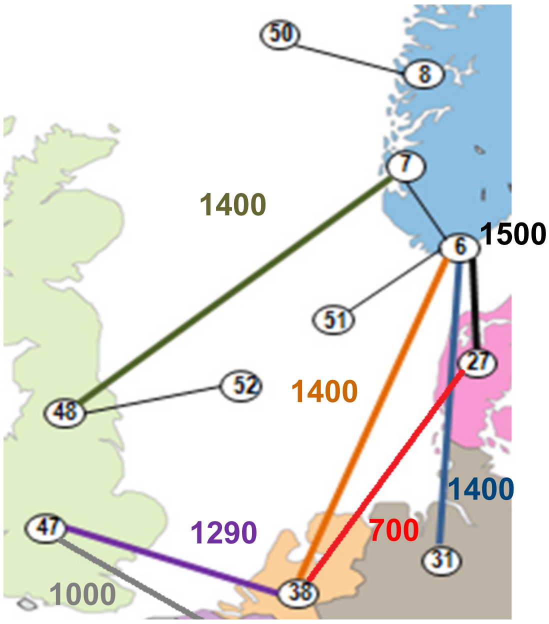


Figure 4.1 North Sea grid in Basecase

4.2 Annual energy balances

Table 4.1 shows the simulated annual energy balances for each simulated country. These are average values for all simulated climate years 1948 – 2004. Numbers are different for any given simulated year because variation in weather-variables affects renewable power generation and consumption. The assumed power system is however the 2020-system as described in Chapter 3.

Table 4.2 shows the difference between annual average values in our simulation for 2020 and IEA's annual energy balance for 2009 [20]. For IEA numbers, we have included electricity for heat pumps and boilers in consumption, while the total own use of electricity for plants using combustible fuels is subtracted proportionally from the gross production of each type. Hydropower is exclusive pumped storage production. In general, the table shows a major shift away from gas-power to renewable power (wind, solar and bio).

Table 4.1 Simulated energy balances for 2020 (TWh). Annual average for climate years 1948 – 2004

	Norway	Sweden	Denmark	Finland	GB	Germany	Netherlands	Belgium
Gross consumptio	140,1	154,6	38,7	102,3	378,1	562,7	136,7	102,3
Export	30,9	42,1	23,3	8,1	3,4	81,2	29,7	6,0
Total use	171,0	196,7	62,0	110,5	381,5	643,9	166,4	108,3
Hydro ex. pumped	133,1	68,5		14,1	6,3	19,9		
Wind and solar	6,5	12,6	11,5	6,1	79,9	146,3	32,4	11,3
Bio		18,4	18,5	17,1	28,6	59,2	19,6	16,5
Coal			16,0	8,8	105,6	226,4	55,3	
Gas	0,5	2,1	3,2	2,3	25,4	21,6	14,9	12,5
Oil		3,8	1,5	0,4		1,7		
Nuclear		75,2		44,3	83,6	134,8	3,8	31,7
Other								
Total generation	140,0	180,7	50,7	93,1	329,4	609,9	126,0	72,1
Import	31,0	16,0	11,2	17,4	52,1	34,1	40,5	36,2
Curtailment								
Total available	171,0	196,7	62,0	110,5	381,5	643,9	166,4	108,3
Net export	0,0	26,1	12,1	-9,3	-48,7	47,1	-10,7	-30,2
RES-E	139,6	99,6	30,1	37,3	114,8	225,4	52,0	27,9

Table 4.2 Change 2009 – 2020 (TWh). IEA's annual energy balances are used for 2009

	Norway	Sweden	Denmark	Finland	GB	Germany	Netherlands	Belgium
Gross consumptio	18,6	16,6	3,9	21,0	20,9	25,7	22,9	18,5
Export	16,3	33,0	12,4	4,7	-0,3	27,1	19,1	-5,3
Total use	34,9	49,6	16,3	25,8	20,6	52,8	42,0	13,2
Hydro ex. pumped	8,3	3,1		1,5	2,2	3,2	-0,1	0,2
Wind and solar	5,5	10,1	4,8	5,8	70,6	101,1	27,8	10,1
Bio		6,8	14,8	8,7	16,6	26,2	12,3	11,4
Coal		-1,5	-0,6	-6,3	3,4	-11,9	29,8	-5,9
Gas	-3,7	0,6	-3,1	-7,0	-134,3	-51,5	-50,9	-15,8
Oil		3,1	0,4	-0,1	-4,2	-7,2	-1,4	-0,3
Nuclear		25,2		21,7	20,8	7,1	-0,2	-13,3
Other				-0,3		-6,4	-0,1	-0,1
Total generation	9,5	47,5	16,3	24,0	-25,0	60,6	17,1	-13,6
Import	25,3	2,2	0,0	1,9	45,5	-7,8	25,0	26,7
Curtailment								
Total available	34,8	49,7	16,4	25,9	20,5	52,7	42,0	13,1
Net export	-8,9	30,8	12,4	2,8	-45,8	34,9	-5,8	-32,0
RES-E	13,5	20,0	19,6	16,0	89,4	130,5	40,0	21,8

Simulated net import is largest for Belgium and GB, while net export is largest for France and Germany, cf. Figure 4.2. In total, there is also a considerably surplus in the Nord Pool area.

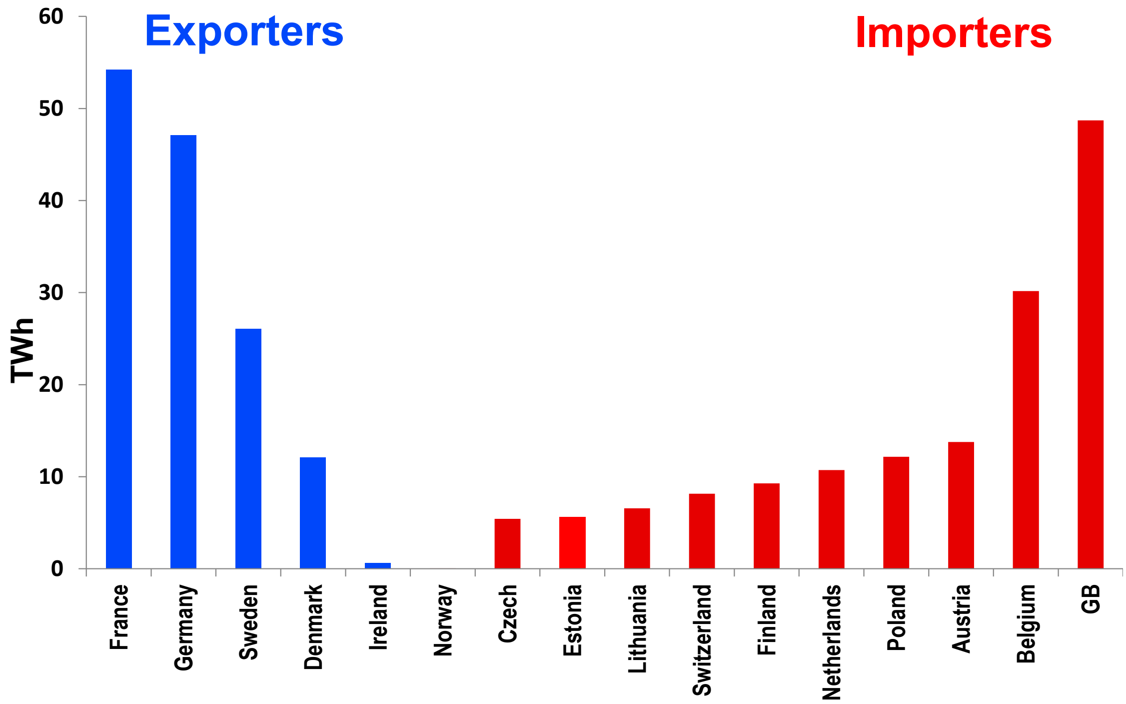


Figure 4.2 Average annual values for net import/export

4.3 Power supply from different technologies

The shares for different technologies and the balance between demand and total supply for each country are illustrated in Figure 4.3. The first column for each country shows the 2009-situation [20], while the second column shows simulated values for 2020.

The development from 2009 to our simulated 2020-situation is different for the different countries. However, for all countries the share for renewable power generation is increased. For wind-power and solar-power, there are only marginal differences between the annual amounts we intended to put into the model, cf. Table 3.1, and the average of simulated values. The production will however vary from year to year. For instance, the standard deviation for simulated annual production is 10,2 TWh for the sum of wind-power and solar-power in Germany. For wind- and solar-power, and mostly for consumption, values are pre-calculated stochastic variables.

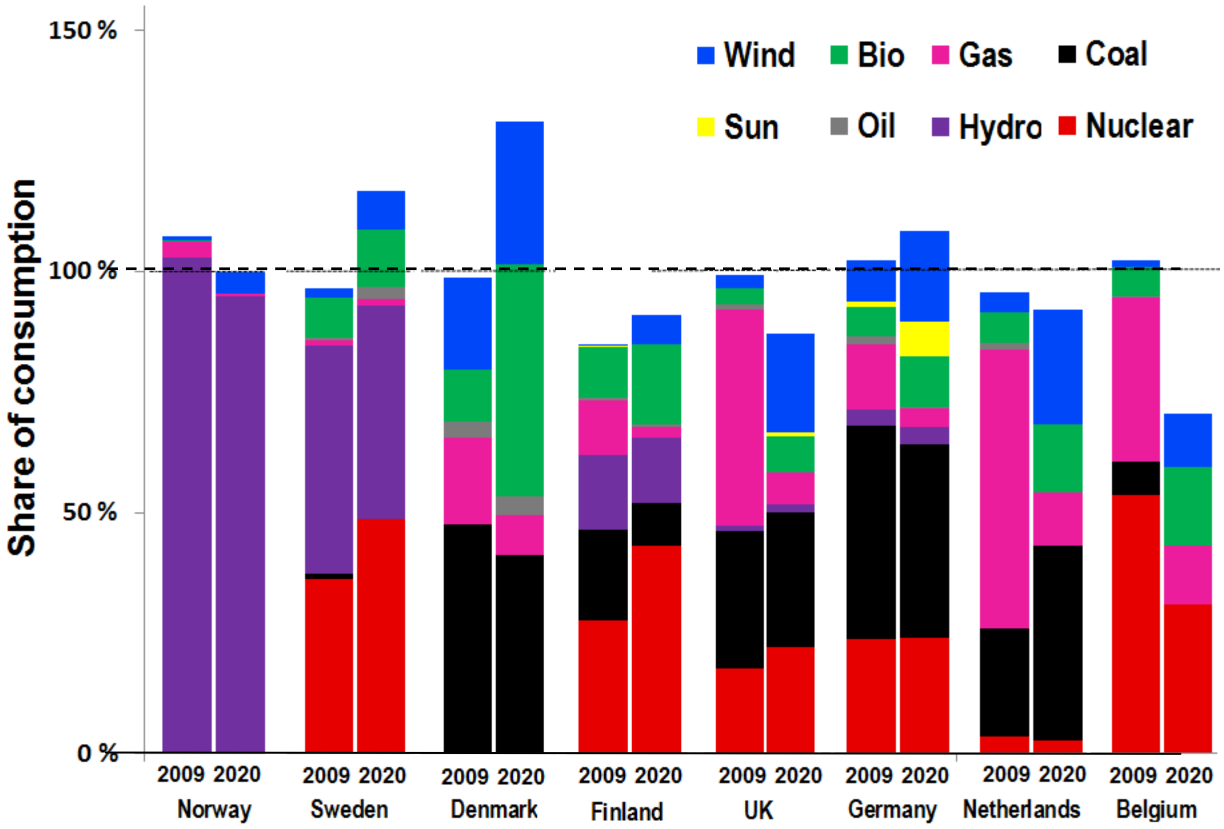


Figure 4.3 Supply shares and balance. Annual average

The use of natural gas is reduced considerably because of high marginal costs compared to coal-power, and the large increase in renewable power generation. See Section 3.4 for a discussion.

For coal-power, the share is increased for the Netherlands, while it is reduced for Finland, Germany and Belgium. For nuclear power the share is increased for Sweden, Finland and GB, but reduced for Belgium. Notably, the share of nuclear power production in Germany is relatively stable. The latest political developments may however lead to a phase-out of nuclear power in Germany.

For bio-power, the simulated production is mainly determined by installed capacity from the ENTSO-E forecast, fuel costs adjusted for RES-E subsidy, and the simulated power prices in the EMPS model. It is therefore no guarantee that the simulated bio-power production will coincide with the targets specified in national action plans. Figure 4.4 shows that the simulated average production is larger than the targets. For Denmark the simulated production is considerably larger than the Danish target specified in the national action plan. We have not evaluated if this is possible considering the availability of biomass, or the effect on biomass-prices in Denmark.

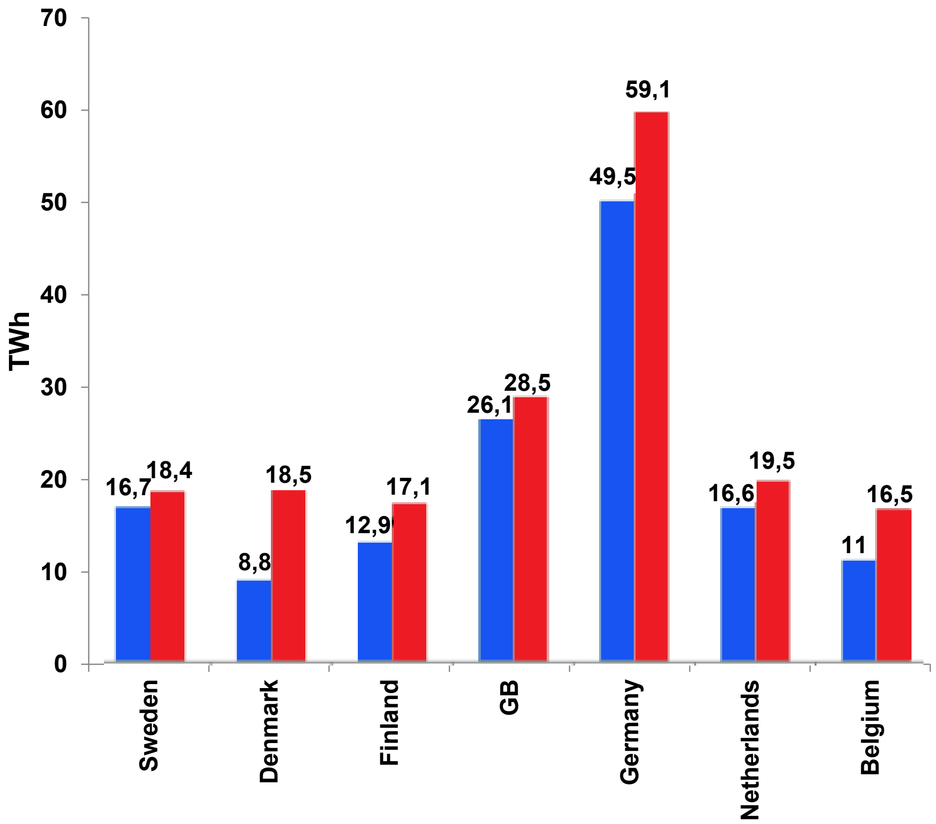


Figure 4.4 Bio-power production in national action plans (blue) and average annual simulated values (red)

4.4 Hydropower

For Norway, average production is increased from 121 TWh to 133 TWh, even though the share for hydropower goes down in Figure 4.3. The relative increase in consumption is larger than the increase for hydropower, leading to a reduced hydropower/consumption ratio.

In Figure 4.5 we have compared year-to-year variability in statistics and simulations for annual hydropower production in Norway in for the 10 last simulated years (1995 – 2004). Average hydropower production in Norway for the period 1995 – 2004 was less than the simulated 133 TWh average in our simulations for 2020, which includes new capacity from the historical 10-year period to today's system plus approximately 12 TWh new hydropower before 2020. Therefore, we have subtracted 17 TWh from simulated values to get comparable numbers. Figure 4.5 shows that there is a close correspondence between simulated production and statistics for hydropower production. It is not expected that the annual production should be exactly the same for each year since the simulated 2020-system is different than the system that existed in 1995 – 2004. It seems to be a tendency that the production is relatively larger in the statistics for the most recent years. The reason for this is probably that new hydropower plants came in operation within the considered period.

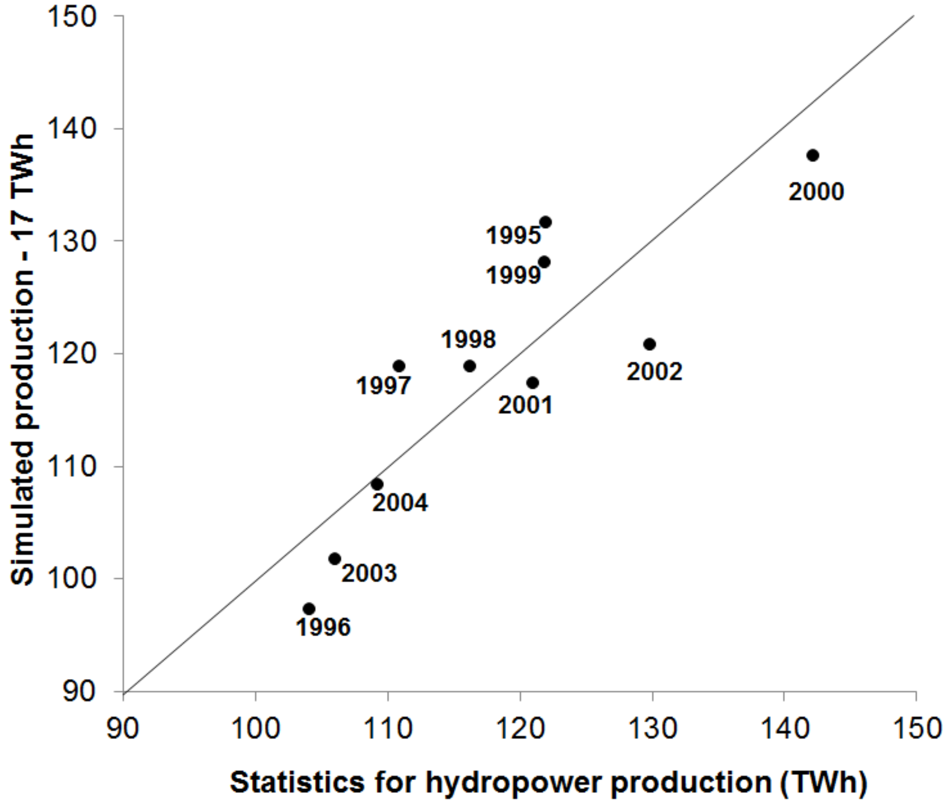


Figure 4.5 **Actual annual hydropower variability for Norway 1995 – 2004, and simulated values minus 17 TWh**

4.5 Electricity prices

Country averages

Electricity prices are affected by fluctuating renewable power generation, especially wind- and solar-power, and congestion leads to different prices between and within countries. Figure 4.6 shows annual average prices for each country.

In Germany, there are relatively more coal-power capacity than in GB, Netherlands and Belgium. This gives lower power prices for Germany since coal-power in general is cheaper than gas-power, cf. section 3.4. In the Nordic area, water values are important for prices. Water-values are in general anchored in the production costs for thermal power generation, but also affected by other factors such as probability for spillage and curtailment. Since the Nordic area is a surplus-area, average power prices tend to be lower than in the non-Nordic areas except France. Finland is a net importer, but the net import is less than the fixed import from Russia, cf. section 3.7. The average price-difference between Norway and GB is of particular interest because North Sea grid alternatives that connect Norway and GB are evaluated.

SINTEF

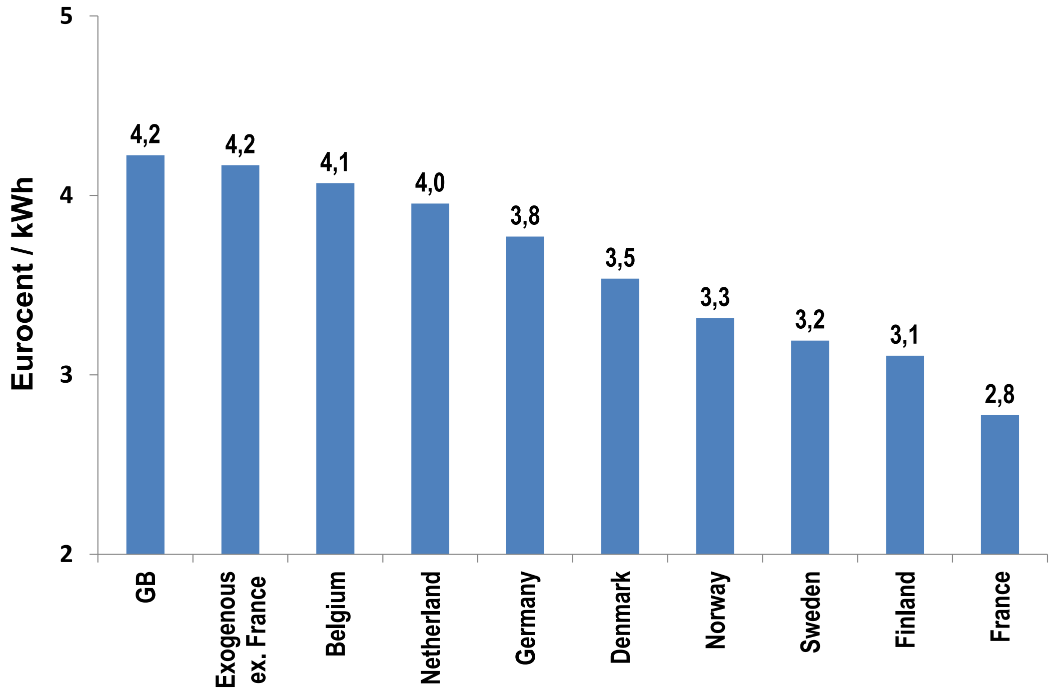


Figure 4.6 Average prices per country

Within-country area averages

Figure 3.1 shows the applied area-names for all areas, while average area-prices for multi-area countries are shown in Figure 4.7- Figure 4.11.

In GB, the price is lowest for the northern area because of the large share of renewable power generation in this area relatively to consumption and other supply-types. This will influence the economic evaluation of different connection points for cables to GB. On the other hand, power price variability is also important. In northern Germany ("TYSK-NORD"), the relatively low price is caused by the large share of renewables in this area, and by several connections to the Nordic countries.

Within Norway and Sweden, prices are lower in the northern surplus-areas than in the southern areas that are connected to continental Europe and GB. The average price in the most southern Swedish area is the same as the average price in Germany.

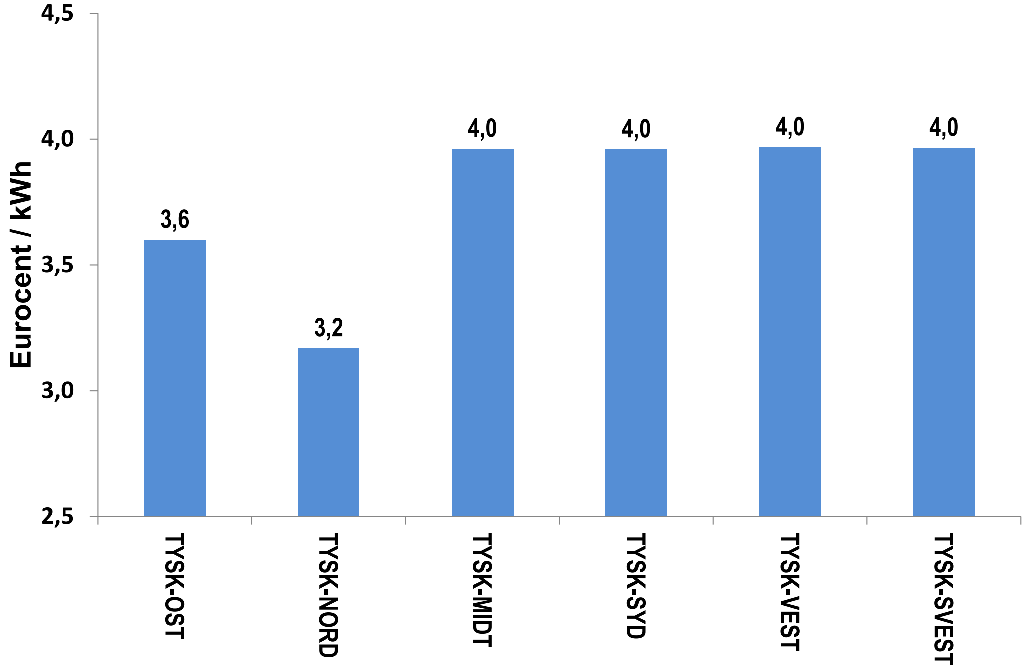


Figure 4.7 Average prices in German areas

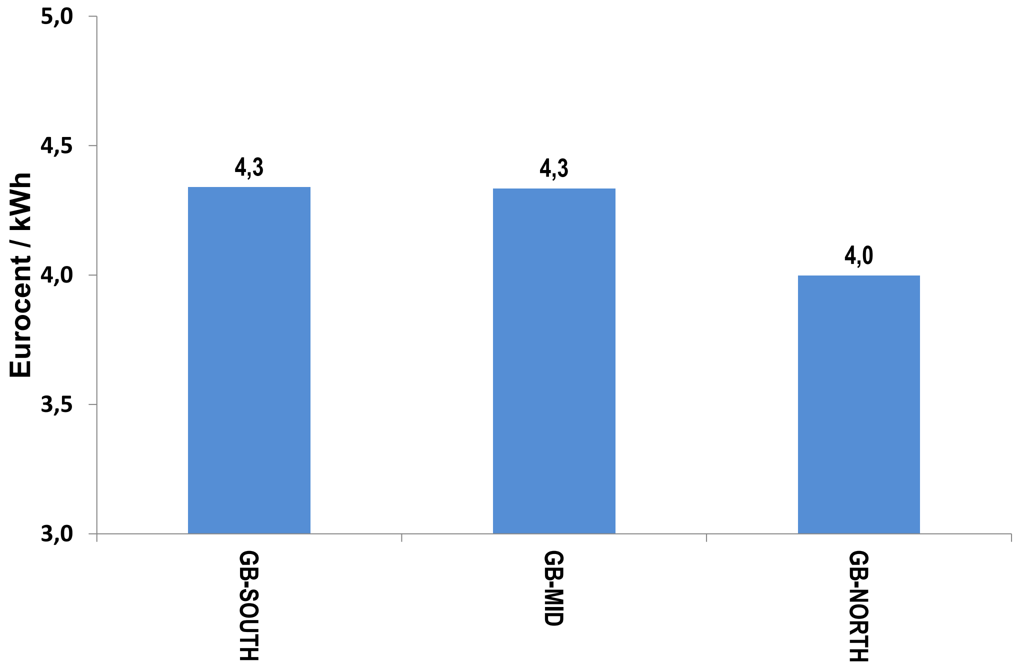


Figure 4.8 Average power prices in GB areas

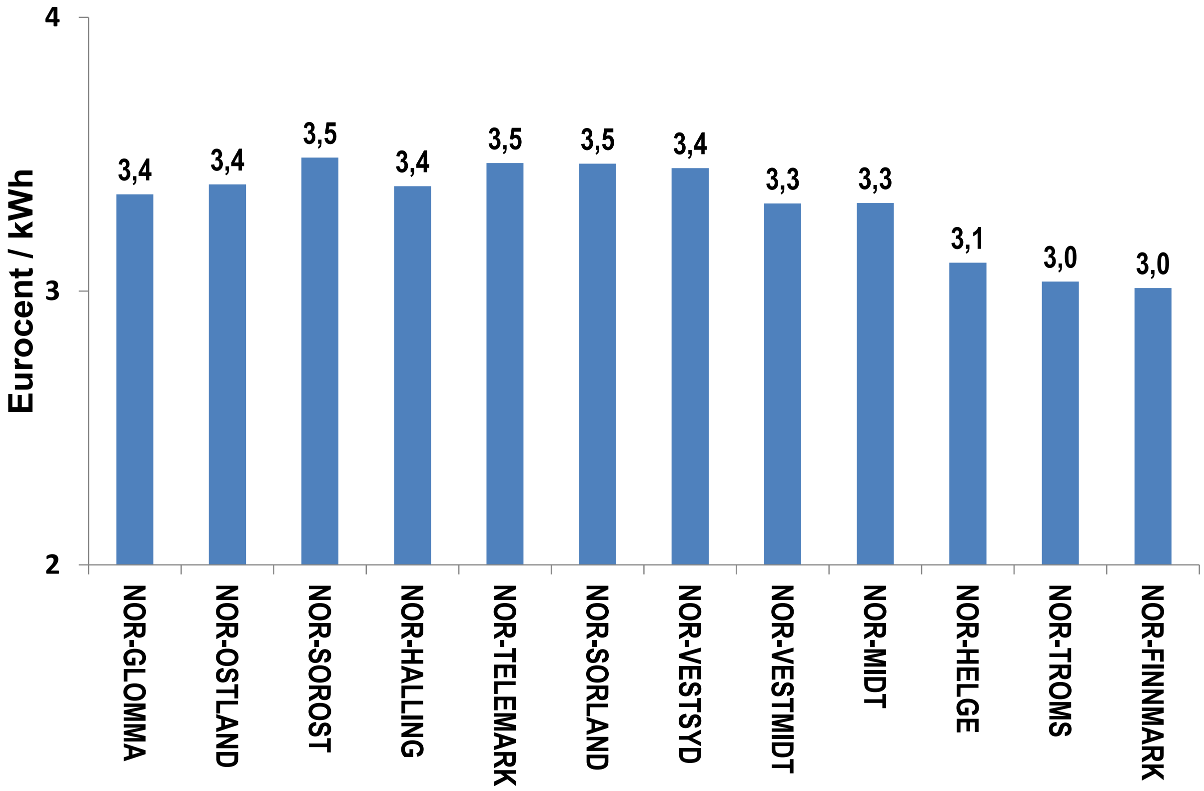


Figure 4.9 Average prices in Norwegian areas

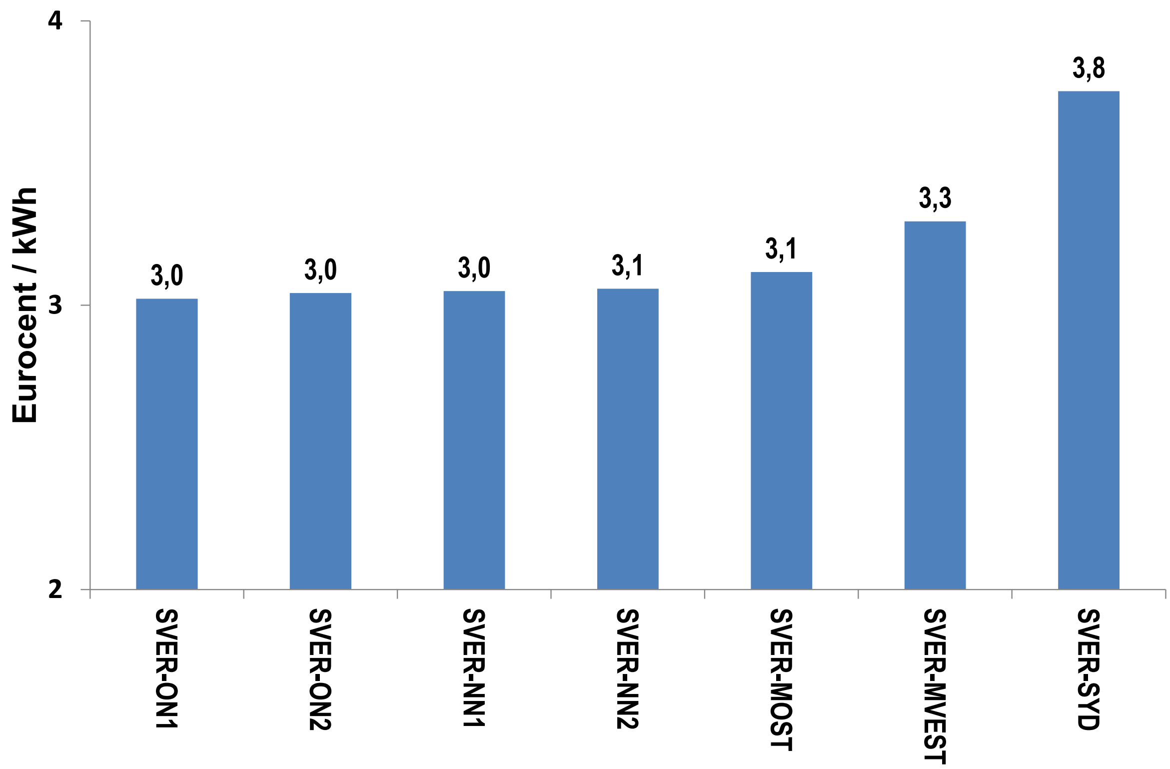


Figure 4.10 Average prices in Swedish areas

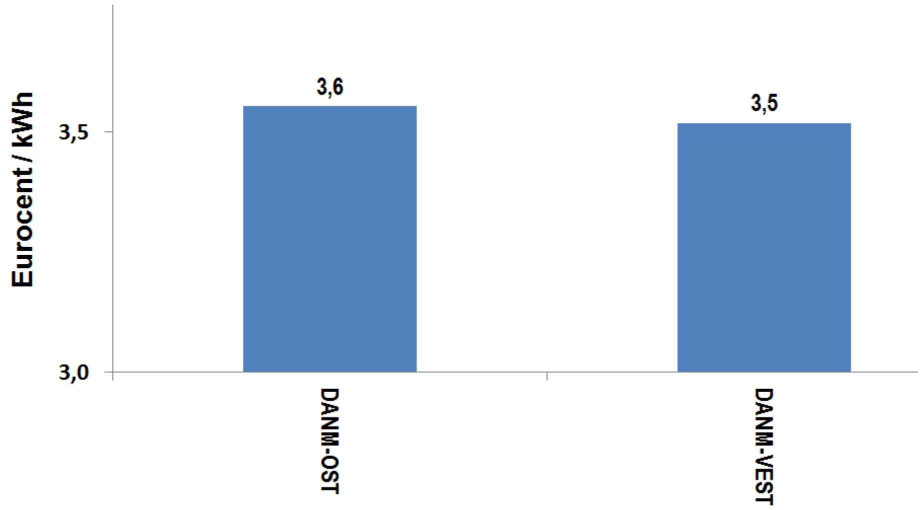


Figure 4.11 Average prices in Danish areas

<u>Within-year, within-week and duration curves for prices in selected areas</u>

Figure 4.12 show the within-year weekly average prices for some selected areas. For NOR-OSTLAND, the average price has a dip at the end of the summer. In some cases reservoirs have been filled up more than expected during the filling season; cf. reservoir-level profiles in Appendix A. This gives a danger for reservoir spillage during the fall, and leads to lower water values. For TYSK-NORD the within-year profile is the opposite of NOR-OSTLAND. Wind-power production is on average larger during the winter than during the summer. See Figure 3.7 for an example. Hence, the large amounts of wind-power connected to TYSK-NORD gives lower average prices during the winter. Appendix B shows the stochastic distribution (percentiles) for prices over simulated climate years for within-year weekly prices in some areas.

Figure 4.13 gives an example of within-week prices for one simulated week. In general, there is relatively little price-variation for the Norwegian area since hydropower is flexible. For the areas in Germany and GB, prices are higher during the day than during the night because of a relatively higher day-consumption. Start-up costs make it more costly to tune the thermal power generation profile to the consumption profile, and this enhances the typical within-week price variation. In addition, wind- and solar-power variability can have a considerable impact on power prices in a given time-step. The example of a high price in southern GB and a low price in two German areas are probably triggered by low and high renewable power generation respectively.

Figure 4.14 shows all simulated prices in 2004 for the selected areas, ordered with decreasing values towards the right. The area GB-SOUTH has the highest average price and the highest simulated prices up to 6,9 Eurocent/kWh. However, there are also examples of prices below 1 Eurocent/kWh for this area. For area TYSK-SYD prices are mostly stable between 4 and 4,5 Eurocent/kWh, but there are some examples of low prices. For Norway, the price-level is somewhat lower. For area TYSK-NORD there are low prices in more occasions than for other areas. The reason for this is large wind-power production and congestion out from this area. In some hours the price goes to a technical minimum price that is set to 0,1 Eurocent/kWh.

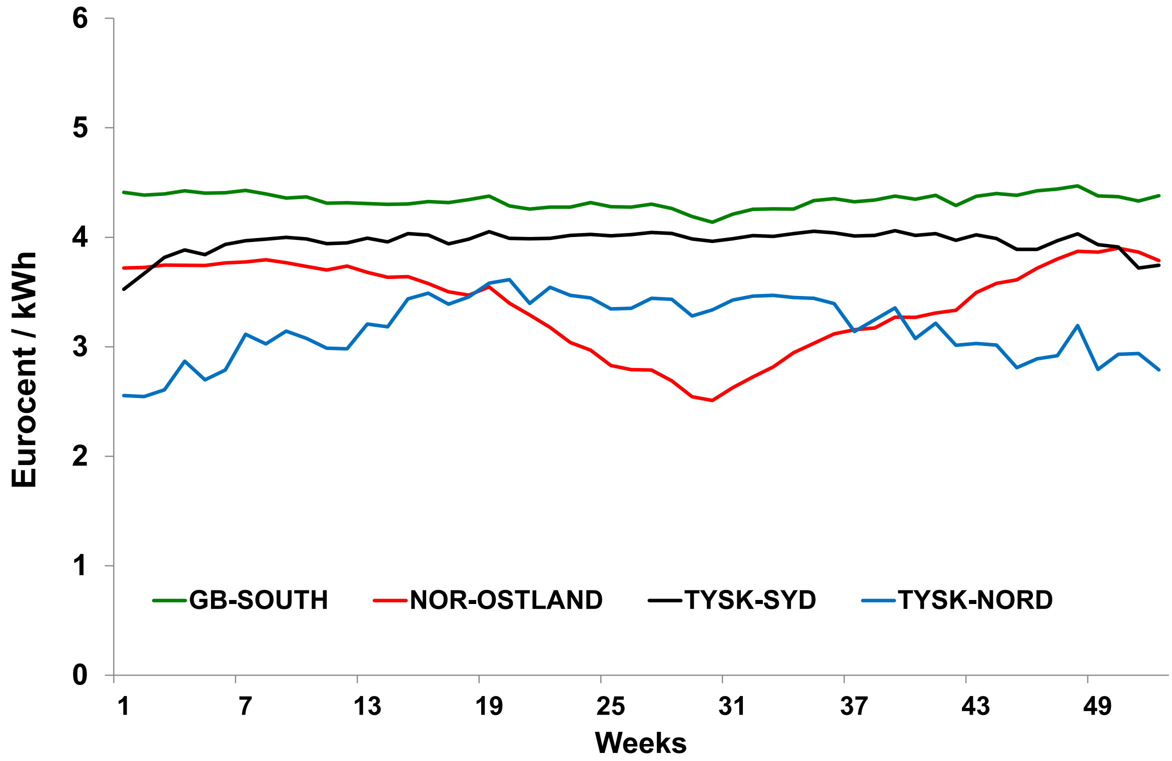


Figure 4.12 Within-year weekly average prices

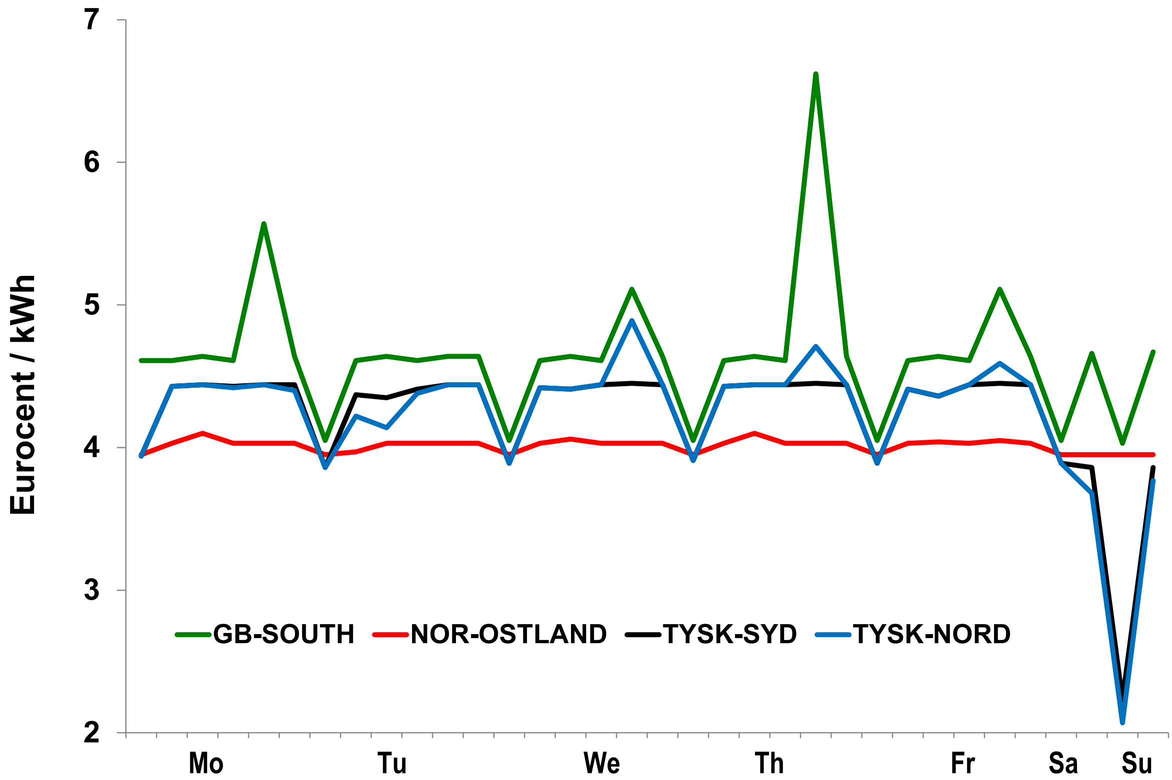


Figure 4.13 Example of simulated prices for one week

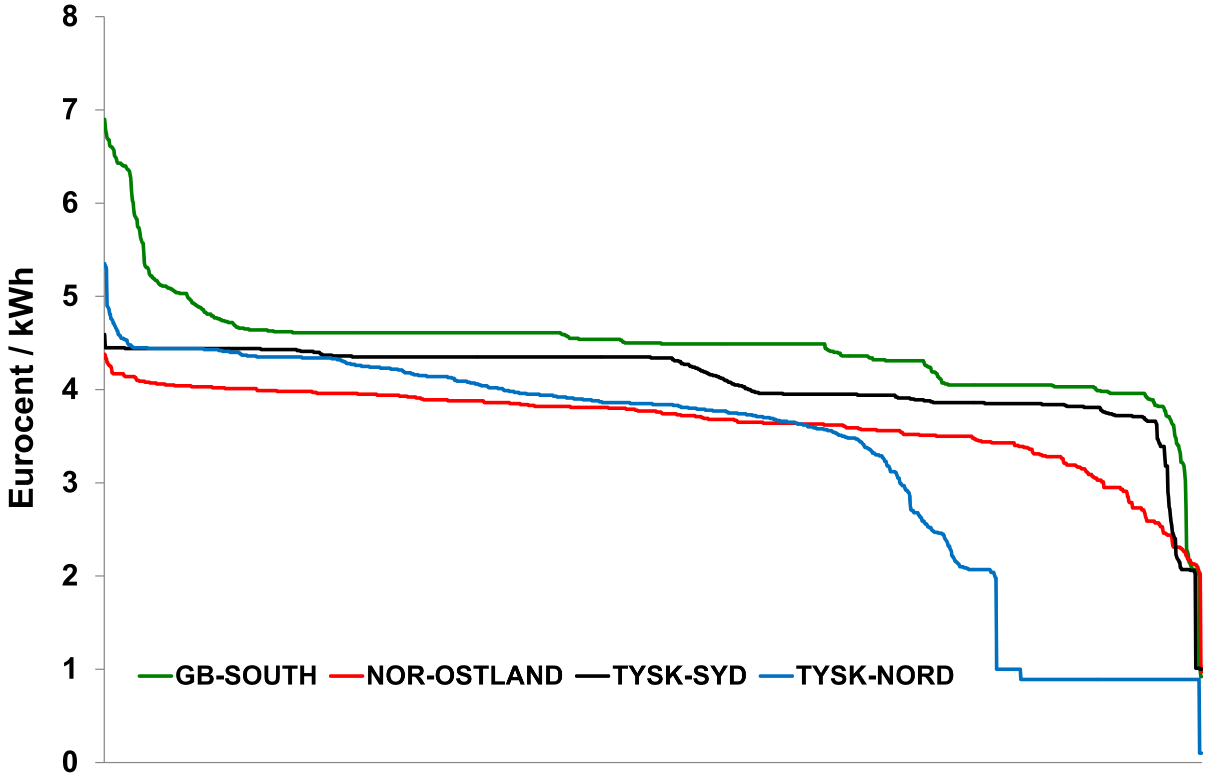


Figure 4.14 All simulated prices in 2004 for 4 areas. Decreasing values towards the right

4.6 Transmission

Country-to-country transmission
The average annual power transmission between countries is shown in Table 4.3. There may be minor deviations compared to Table 4.1 mainly because of the different aggregation levels (sequential vs. aggregated within-week load periods) and losses.

Major flows
The annual transmission of electricity in the simulated system is illustrated in Figure 4.15. The figure shows net flow (difference between export and import), and only for those cases where net flow exceeds 10 TWh/year on average. The sum of arrows to/from a country will therefore not add up to the average net export for the country in Table 4.1.

In Sweden, there is a considerable surplus in the northern regions that flows southward in Sweden and into Norway and to GB. In GB, the surplus in the northern area is transmitted southward. There is some congesting between the northern area and the mid-area, cf. the flat maximum segment in Figure 4.16. In general, there is however not congestion from the mid-area to the southern area. For GB, there is considerable import from France, Netherlands and Norway. Power flows towards the southern parts of GB and to Belgium from all directions. Within Germany, power is transmitted southward from the northern area, and westward from the eastern area and mid-area. The Netherlands is a major importer from Germany, and an exporter to Belgium and GB. The Dutch average price is between the relatively high prices for GB and

Belgium, and relatively low price for northern Germany. At full utilization, the export from northern part of Germany to Netherlands would be 17,7 TWh. The average annual transmission is 16,0 TWh. There are connecting lines also between the western parts of Germany to the Netherlands.

Table 4.3 Country-to-country transmission matrix for Case A1

From\To	NO	SW	DK	FI	GB	NL	GE	BE	Others	Sum
NO		2,9	2,9	0,4	10,6	8,8	3,2			28,7
SW	22,8		2,6	6,5			0,1		9,9	41,9
DK	2,6	8,0				5,2	5,6			21,3
FI	0,1	2,4							5,6	8,2
GB	0,4					0,0		0,3	1,4	2,1
NL	0,2		0,0		10,2		7,0	10,4		27,9
GE	3,3	2,2	3,4			24,3			42,5	75,7
BE					5,5	0,3			0,0	5,8
Others		0,2		10,5	24,7		12,7	25,4		73,5
Sum	29,4	15,7	8,9	17,4	50,9	38,6	28,6	36,1	59,4	284,4

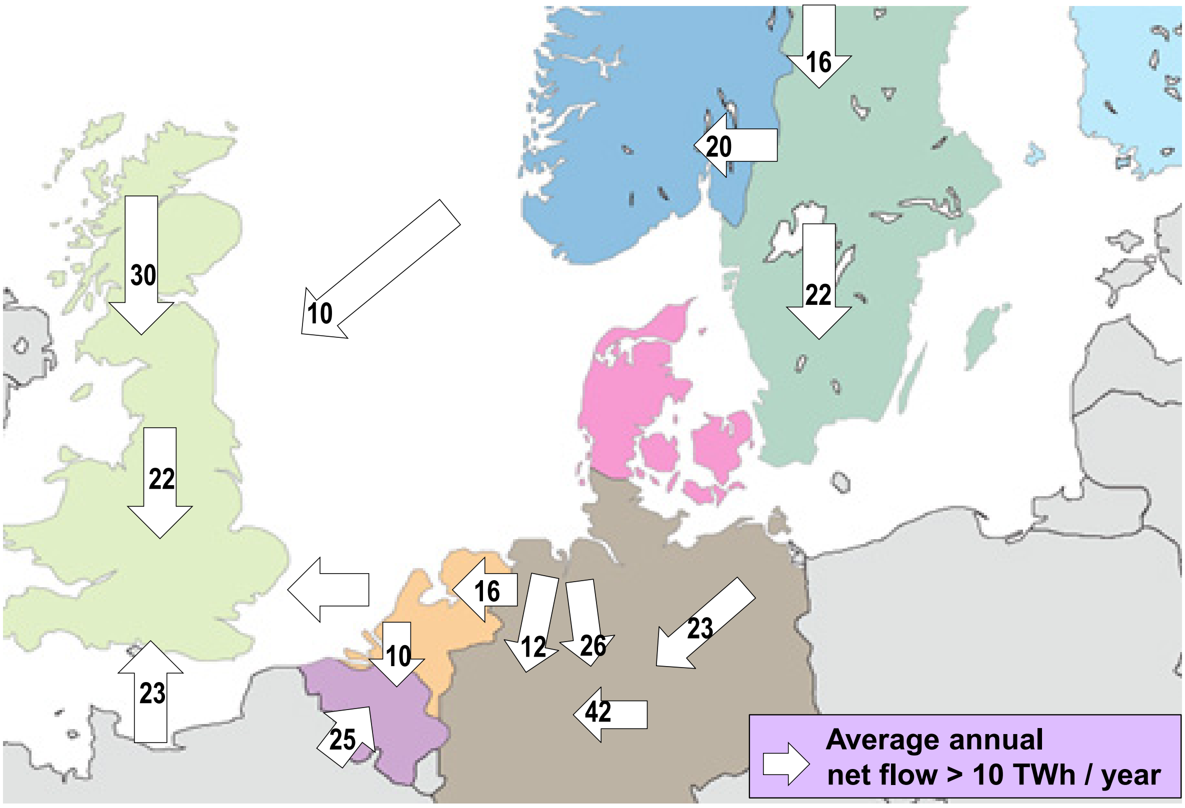


Figure 4.15 Average net electricity transmission per year in Basecase (in TWh)

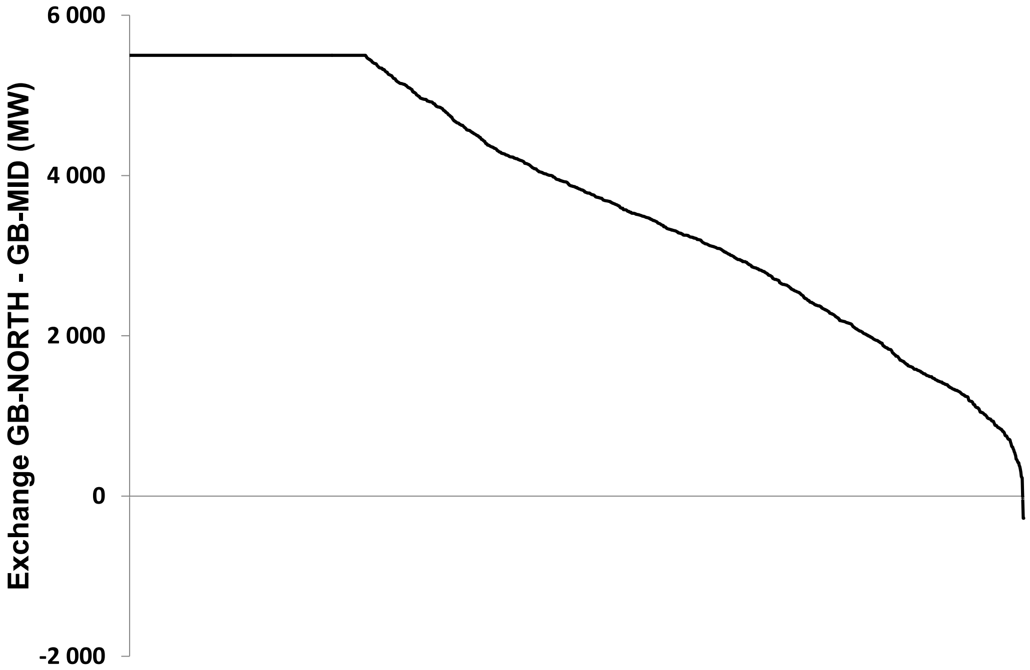


Figure 4.16 Transmission between GB-NORTH and GB-MID. All simulated time-steps in 2004

<u>North Sea cables</u>

The simulated transmission for all aggregated load-periods (7 values per week in 47 climate years) for each North Sea cable connected to Norway is illustrated in Figure 4.17. The average net export from Norway to GB on the 1400 MW direct connection is 10,2 TWh, which is close to the 12,2 TWh maximum. This is a consequence of the relatively high power-price in GB, cf. Figure 4.6. The cable to the Netherlands is also mostly used for export for the same reason. The transmission towards Denmark and the northern area in Germany is however more balanced since differences in average prices are lower. Actually, the average price is lower in northern Germany than in southern Norway.

<u>Within-week pattern for transmission between Norway and the European continent</u>

Figure 4.18 shows average transmission between Norway and Denmark, Netherlands and Germany for each within-week load-segment. On average, there is export from Norway to all of these countries during daytime (sum for high day, low day and high evening), while there is import from all countries except the Netherlands during night and in week-ends. There is export to the Netherlands also at night and during the week-end because of higher power prices, cf. Figure 4.6.

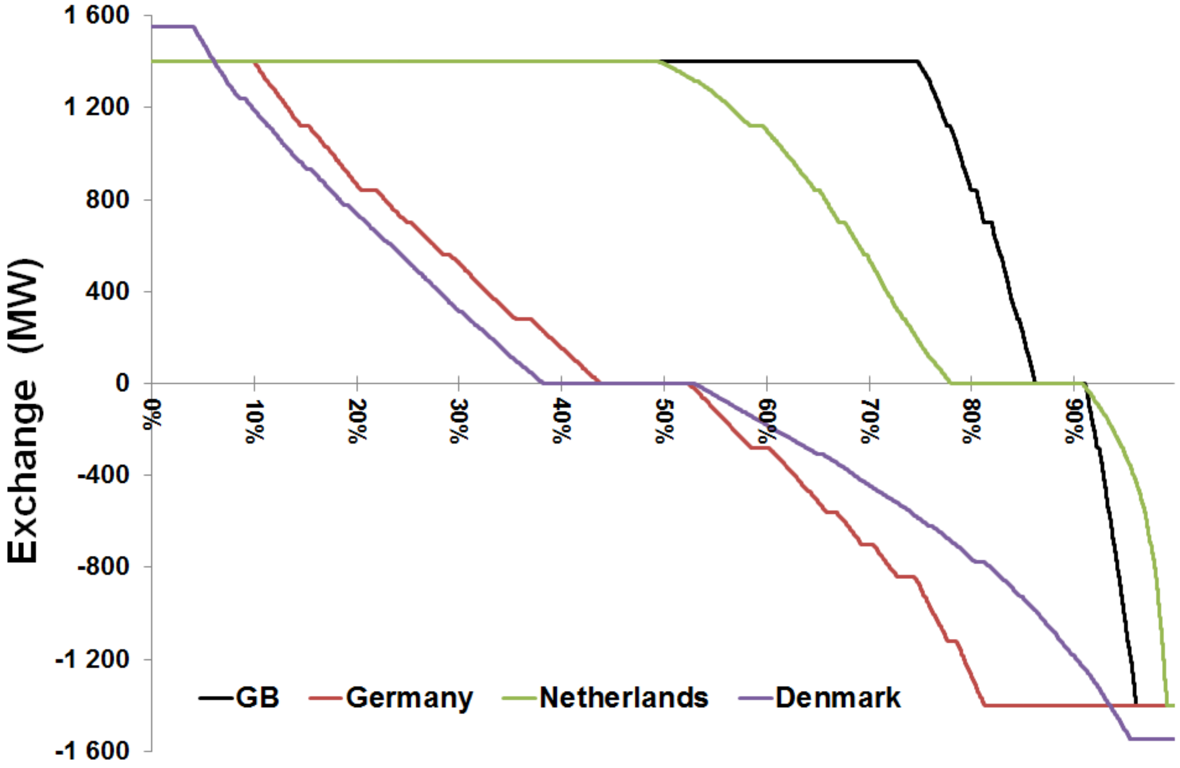


Figure 4.17 North Sea transmission to/from Norway in Basecase. All simulated load-periods

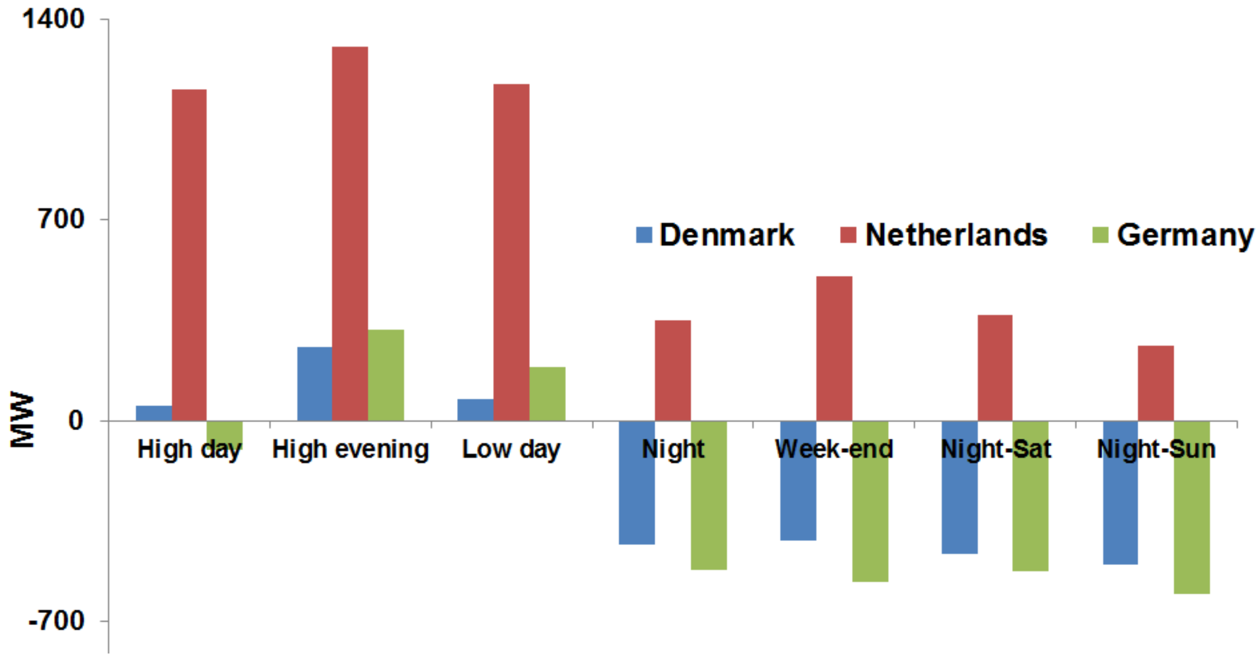


Figure 4.18 Average transmission between Norway and continental Europe in different within-week load periods

4.7 Evaluation thermal power capacity investments

In long-term models that determine investments in new capacity, invested amounts typically balances operating profits towards investment costs. However, our simulations are based on ENTSO-E's capacity-forecast for 2020. Figure 3.10 shows assumed capacity increases per country and technology from the present system to 2020. There is a considerable capacity increase for biomass-based power production and gas-power.

Since our capacities are based on a forecast, there is no guarantee that simulated prices gives a balance between operating profits and investment costs. In the following we give a brief evaluation of the profits and investment costs for additional thermal power capacities. The motivation for this is to help the reader to assess the overall realism in our study, and not to carry out investment analysis for specific technologies or projects. For wind- and solar-power, subsidy schemes are needed to make the planned investments profitable. We have not analysed how much subsidy is needed.

A joint report by International Energy Agency (IEA) and the OECD Nuclear Energy Agency [24], shows a considerable variation in investment costs between different countries. In our evaluation, we utilize costs reported by Eurelectric in [24] when available, and costs reported by EPRI otherwise. In Table 4.4, investment costs (in USD per kWe) and lifetimes are in accordance with [24]. For the annualized costs we have assumed 5 % interest rate, and 1,34 USD per Euro.

Table 4.4 Investment costs for thermal power generation

Technology	Investment cost (in USD/kWe) [24]	Lifetimes	Annualized costs (in Euro/kWe per year)
Black coal	2 205	40	96,4
Gas	1 292	30	63,0
Biomass[3]	3 247	n.a.[4]	141,9
Nuclear	5 575	60	220,9

Table 4.5 shows calculated operating profits for thermal power generation technologies in selected areas. This is simply the integral of prices above marginal costs for the climate year 2004. In this calculation, we have not accounted for start-up costs or interplay with heat market. Nor is the possible extra profits from supplying balancing services for deviation between the spot-market solution and real-time operation accounted for.

The operating profits for new gas-power are close to zero in our simulation. For most cases there is enough coal-power capacity available at a lower marginal cost. As a consequence, gas-power capacity is often unused, and operating profits is often low when in use. For coal-power, annual operating profits is in the range 50,1 – 75,4 Euro/kW, which is lower than the 96,4 Euro/kW investment cost. For bio-power, operating profits, which includes a subsidy that reduces marginal costs, is roughly the same as investment costs. Operating profits is higher than the 141,9 Euro/kW investment cost for some areas, and lower for others. For nuclear power, operating profits is slightly higher than the 220,9 Euro/kW investment cost.

[3] For biomass the cost-estimate is explicitly for electric capacity in CHP.
[4] For calculation of annualized costs we use 40 years.

Table 4.5 Operating profits for thermal power generation in 8 areas. Evaluated for climate year 2004 (in Euro/kWe per year)

Area \ Fuel	Coal	Gas	Bio	Nuclear
DANM-VEST	52,1	0,2	134,8	242,4
SVER-SYD	50,9	0,1	134,5	242,5
FINLAND	50,1	0,1	133,7	241,6
BELGIUM	58,0	0,1	141,0	245,5
NETHERLANDS	57,4	0,2	133,1	228,3
TYSK-NORD	62,3	0,3	141,4	240,4
TYSK-SYD	75,2	0,2	165,3	274,4
GB-MID	75,4	0,3	165,6	274,6

Clearly, simulated power prices are too low to provide a sufficient incentive for investments in new gas-power plants. The example in Section 3.4 showed a marginal cost of 4,5 Eurocent/kWh for gas-power, which is above the average price in all areas. Also, additional retirement of capacity would be likely at this low operating profit for gas-power. In our simulations, there is new gas-power capacity especially for Netherlands and Belgium. The effect on power prices of assuming no new gas-power in the Netherlands and Belgium would however be moderate since there is available capacity in existing less efficient gas-power. The change in gas-power production from 2009 to our simulated 2020 simulation is minus 50 TWh and minus 15 TWh per year for the Netherlands and Belgium respectively.

In sum, simulated production and prices would probably not be totally different if the model had determined investments in new production capacity. Probably it would also be possible to retire a large share of the existing gas-power capacity in some countries without affecting simulated power prices considerably.

5 North Sea grid cases

5.1 Overview

In total, 10 alternative off-shore grid configurations for the North Sea are studied, cf. Table 5.1 and Figure 5.1. Results for Basecase were presented in Chapter 4. For a 2nd connection between Norway and GB we consider direct connections for different connection points in both countries (no 2 – no 5), integration with North Sea nodes (no 6 – no 8), and an integrated grid that include a connection to Germany (no 9 and no 10).

For each case we present some selected simulation results of particular interest for that case. The economic assessment (operating surplus and investment costs) is considered in Chapter 6. We have also carried out simulations for additional cases to study important uncertainties in the specification of the power system for 2020. These additional cases are documented in Chapter 7.

Table 5.1 Overview of North Sea grid cases

No	Case	Short description
1	A1	This is Basecase. Only direct connections in the North Sea (country to country, and from wind-farms to shore). One 1400 MW cable between Norway and GB.
2	A2	Two direct 1400 MW cables between Norway and GB.
3	B1	Connection further north in Norway for 2nd cable
4	B2	Connection further north in Norway and GB for 2nd cable
5	B3	Connection further south in Norway for 2nd cable
6	C1	Northern integration
7	C2	Southern integration
8	C3	Doggerbank integration
9	D1	Flexible southern transmission – Norwegian side
10	D2	Flexible southern transmission – three legs

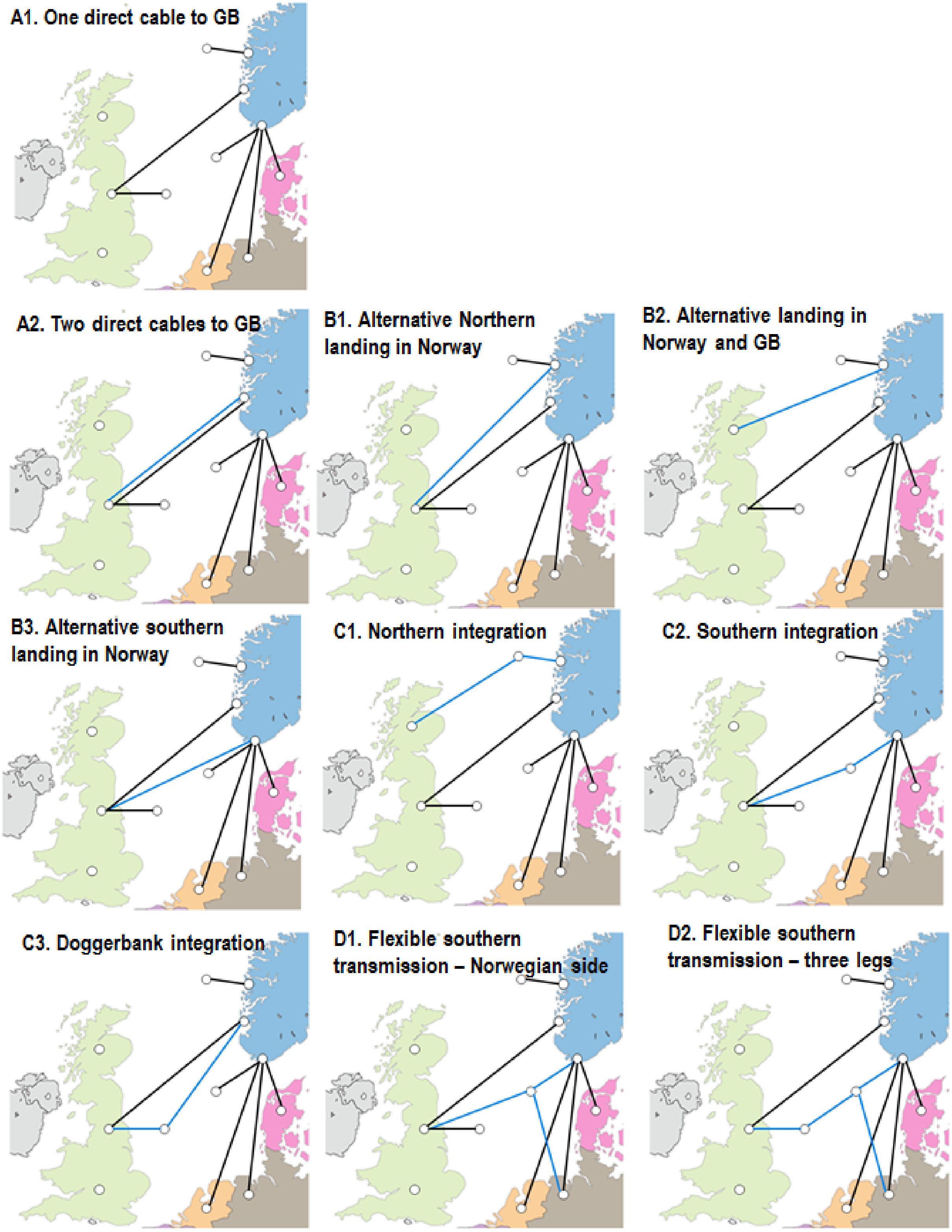


Figure 5.1 North Sea grid alternatives

5.2 Case A2. Two direct 1400 MW cables between Norway and GB

2nd direct connection

A major goal for this study is to compare only direct connections for the North Sea transmission with a more integrated grid. However, it was decided that one direct connection between Norway and GB should be included in all cases since this is likely to be built without considering more integrated options. For a 2nd cable between Norway and GB we study different connection points and North Sea node integration. In Case A2, the 2nd cable connects the same two areas as the first cable, cf. Figure 5.1. The capacity for each cable is 1400 MW.

Country-to-country transmission

Figure 4.17 showed that the 1400 MW capacity between GB and Norway was a major constraint for the optimization in Basecase. Thus, the export from Norway to GB increases when we add an extra 1400 MW cable. Table 5.2 shows changes in country-to-country transmission because of the 2nd cable between GB and Norway. The export from Norway to GB increases by 8,7 TWh, or 82 %. This implies that the 2nd cable also is used mainly for export from Norway to GB. To balance the increased export to GB, the export from Norway to other countries is reduced, while the import is increased. For GB, import from other countries is slightly reduced, while the export is increased. In total, net import increases by 5,7 TWh, which is used to reduce the relatively expensive power generation within GB.

Table 5.2 Changed country-to-country transmission matrix (Case A2 vs. Case A1)

From\To	NO	SW	DK	FI	GB	NL	GE	BE	Others	Sum
NO		-0,7	-1,1	0,0	8,7	-1,3	-0,8			4,8
SW	3,2		-0,3	-1,5			0,0		-0,8	0,6
DK	0,6	0,5				-0,3	-0,9			-0,1
FI	0,0	0,6							0,0	0,6
GB	0,5					0,0		0,2	0,2	0,9
NL	0,1		0,0		-0,4		-0,5	-0,2		-1,1
GE	0,8	-0,1	0,4			0,1			-0,7	0,3
BE					-0,5	0,0			0,0	-0,5
Others		0,1		0,0	-1,2		0,1	-0,3		-1,3
Sum	5,2	0,3	-1,0	-1,6	6,6	-1,6	-2,2	-0,3	-1,3	4,2

North Sea cables

The utilization of North Sea cables connected to Norway in Case A1 and Case A2 is illustrated in Figure 5.2. The number of occasions where there is full utilization of the capacity from Norway to GB is reduced from 75 % to 60 %. While the export to GB has increased, the net export is reduced towards Germany, Netherlands and Denmark.

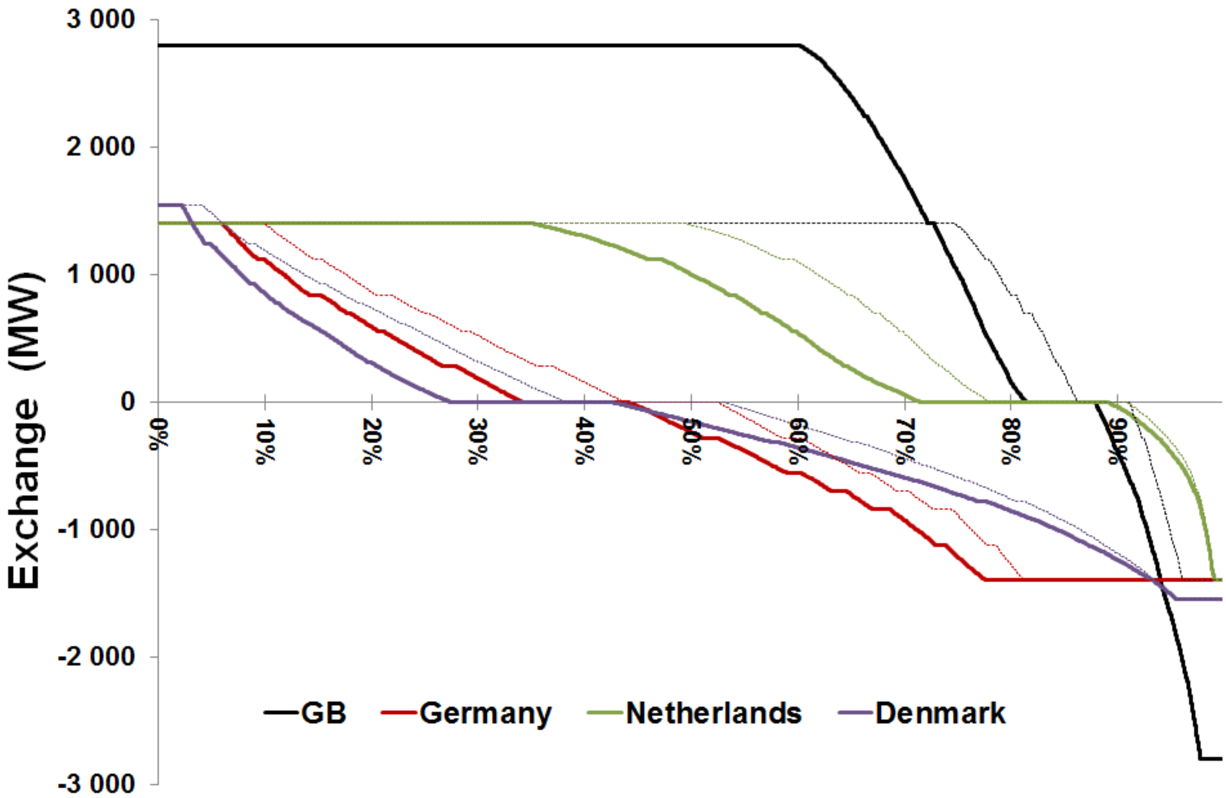


Figure 5.2 **North Sea transmission to/from Norway in Case A2 (solid curves) and Case A1 (thin dotted curves). All simulated load-periods.**

<u>Thermal power generation</u>

Table 5.3 shows how thermal power generation changes from Case A1 to Case A2. The extra import to GB is used to reduce domestic production, especially gas-power. This is mainly compensated by increased coal-power production in Germany and Finland.

Table 5.3 Thermal power generation in Case A2 compared to Case A1. Average values in TWh/year

	Gas	Coal	Bio
GB	-4,4	-1,1	
Germany	0,1	2,3	0,1
Finland		1,7	0,4
Denmark	0,1	0,6	0,1
Netherlands	0,2	0,3	
Sweden			0,3
Belgium	-0,2		
Norway	0,1		

<u>Electricity prices</u>
GB has highest electricity prices in our simulations. Consequently, the additional cable from Norway to GB gives additional export to GB and higher prices in Norway. The price-increase is 0,22 Eurocent/kWh on average, cf. Figure 5.3. There is a price-increase for the whole Nordic region since the additional export from Norway to GB affects trade. The effect on the British price is however small.

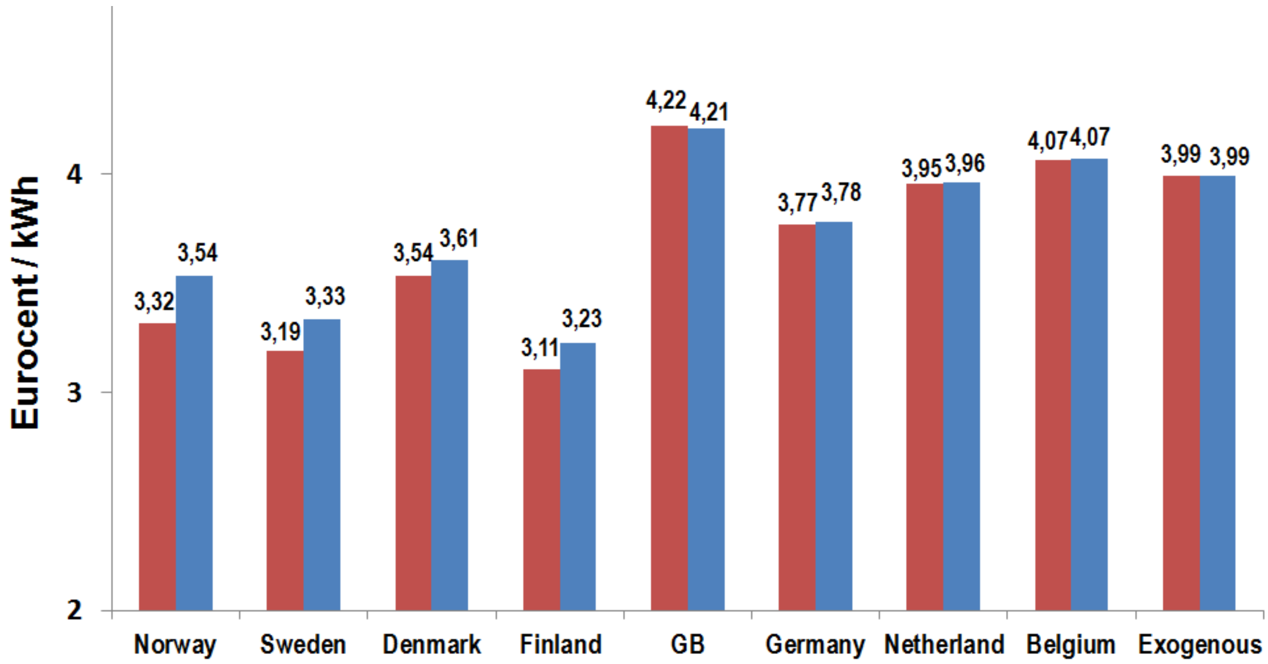


Figure 5.3 Average power prices in Case A1 (red) and Case A2 (blue)

5.3 Case B1 – B3. Different connection points for 2nd cable

<u>Cases of different connection points</u>
In Case B1, B2 and B3 we consider the effects of selecting a different connection point for the 2nd direct connection between GB and Norway, compared to Case A2. In Case B1 and B3, the cable is moved northward and southward in Norway respectively. In Case B2, the cable is moved northward in Norway and GB. Figure 5.1 illustrates the different cases.

The motivation for considering the different connection points is firstly that the energy situation may be different in the different areas within Norway and GB. For instance, the there is a considerable amount of wind-power and lower prices in the GB-NORTH area. Secondly, direct connection cases give a basis for isolating the effects of connecting the cables to the Norwegian off-shore nodes.

Electricity prices

Simulated average electricity prices for 5 cases are shown in Figure 5.4. For each Norwegian area, the simulated average price is highest when the 2nd cable is connected to this area. For GB-MID there are only minor differences for the different scenarios. However, for GB-NORTH, the average price is highest for the Case B2. In this case the connection point for the 2nd cable is in GB-NORTH.

The average price in NOR-VESTMIDT is higher than in GB-NORTH. Therefore, it may be surprising that the average price in GB-NORTH goes up the area is connected to NOR-VESTMIDT. However, the cable gives fewer instances of very low prices in GB-NORTH because of high wind-power production, cf. Figure 5.5. Therefore, the average price in GB-NORTH is reduced even though the cable is used mostly for import from Norway.

North-south transmission within GB

There is a considerable transmission from GB-NORTH to GB-MID in the Basecase, cf. Figure 4.15. The 2nd cable between Norway and GB is mostly used for export to GB. Therefore, the need for transmission from GB-NORTH to GB-MID is increased when the 2nd cable is connected to GB-NORTH. This is shown in Figure 5.6. Increased congestion between GB-NORTH and GB-MID represent a system cost of moving the connection point to the northern area.

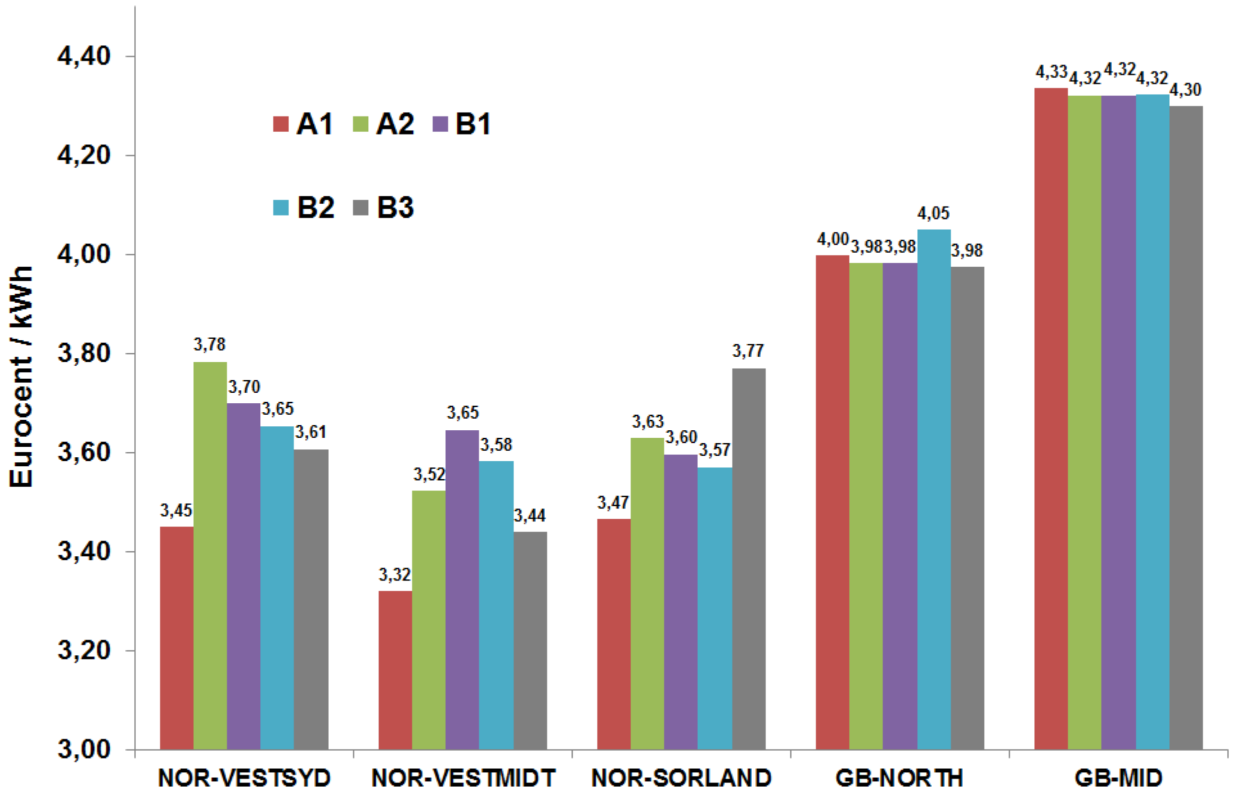


Figure 5.4 Electricity prices for A- and B-cases for selected areas in Norway and GB

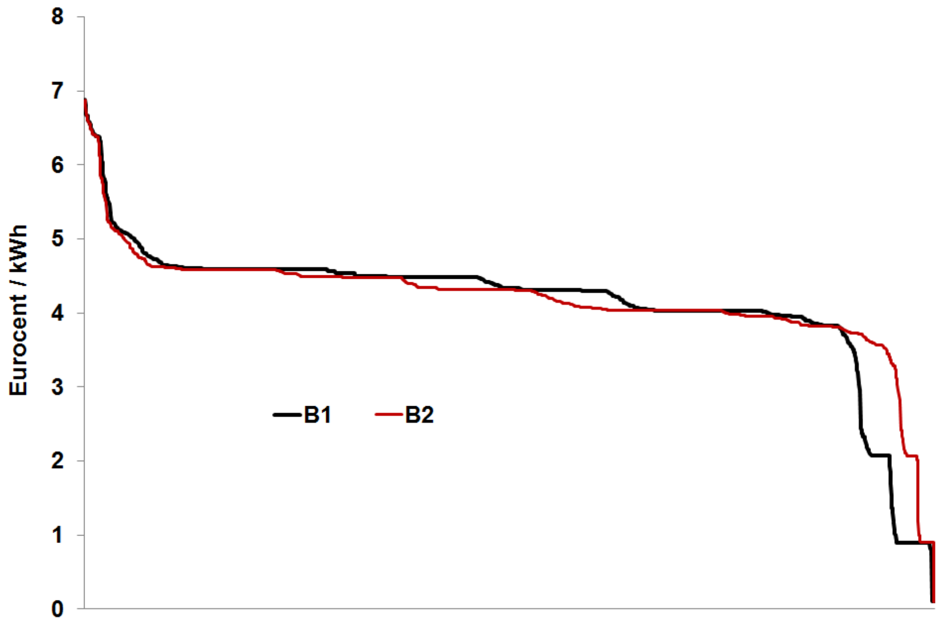


Figure 5.5 All simulated electricity prices in GB-NORTH in Case B1 and B2 for climate year 2004

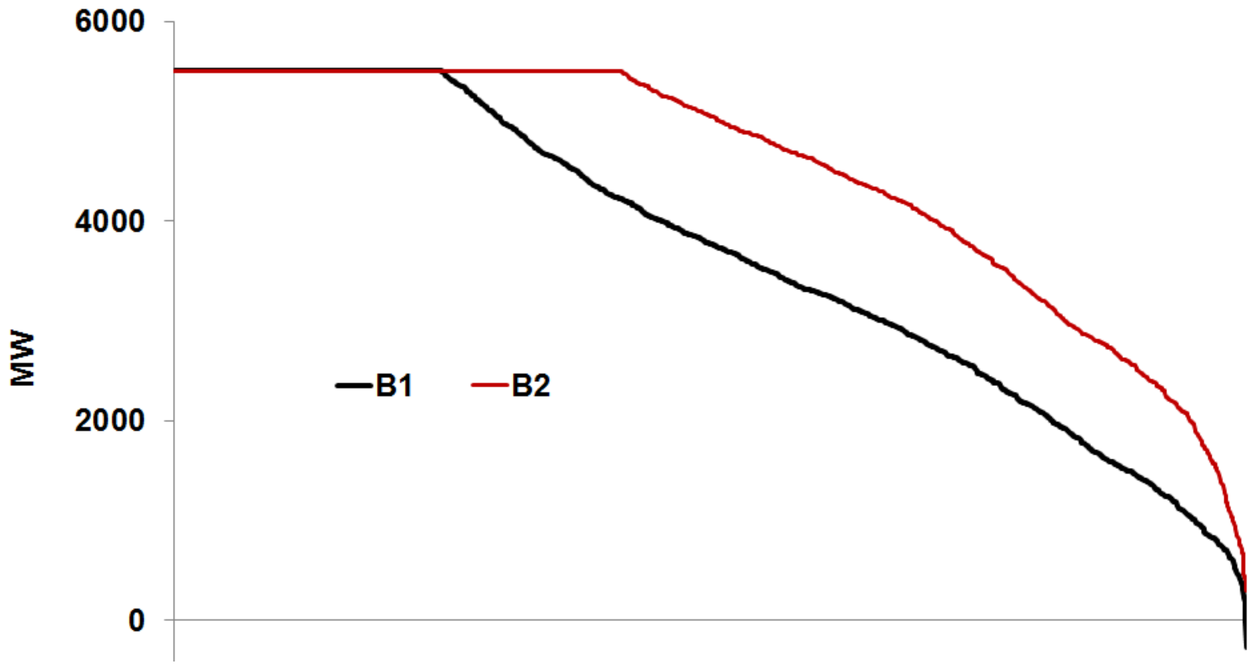


Figure 5.6 Simulated transmission between GB-NORTH and GB-MID in Case B1 and B2 All simulated values for year 2004

5.4 Case C1 – C3. North Sea node integration

On the Norwegian side there are two North Sea nodes (area 50 and 51), cf. Figure 3.1. Each node include wind-farms and electrification of petroleum installations as shown in Figure 3.2. For the northern node, area 51, electricity consumption is always higher than wind-power production. Consequently, this area is always importing electricity. If the 2nd cable between Norway and GB is connected to this node, this reduces the potential for export from Norway. This is illustrated in Figure 5.7.

In the example, the power transmission from the Norwegian mainland towards GB is at the maximum 1400 MW. The net consumption in the North Sea node (consumption at petroleum installations minus wind-power production) is 100 MW for a given hour. Therefore, only 1300 MW reaches the British side where prices are higher. This gives increased system costs compared to a case where the cable is a 1400 MW direct connection.

If the price in Norway is highest when 100 MW is consumed in North Sea node, 1400 MW can be exported from the British side to Norway (i.e. to the Norwegian North Sea node). Of this, 1300 MW will be available for Norwegian mainland. If case of a 1400 MW direct connection to Norwegian mainland, 100 MW would be sent out to North Sea grid from the mainland. The net effect for Norwegian mainland is therefore the same as in a case of direct connections only.

If the North Sea node had been a surplus-area, the situation would be the opposite: reduced potential for import from GB, but unchanged potential for export to GB.

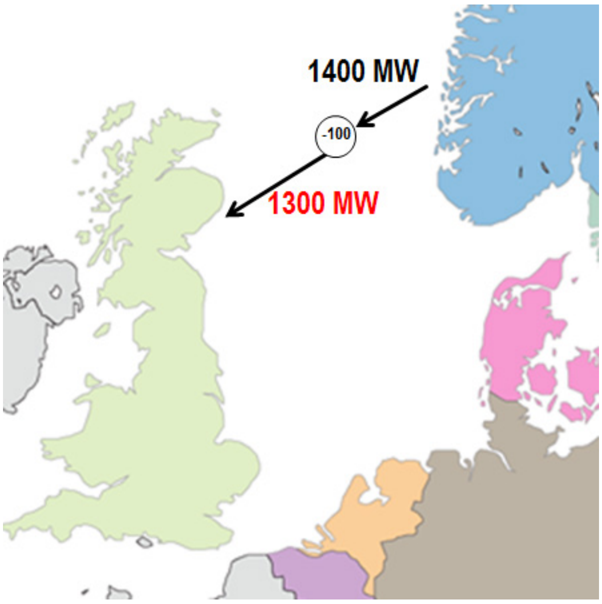


Figure 5.7 Reduced export potential for a cable that goes through a net consumption node

Figure 5.8 shows the simulated effect of connecting the 2nd cable between Norway and GB to the northern North Sea node (area 51). The diagram is a cross-plot for transmission and price-differences between Norway and GB in Case B2 (black) and Case C1 (red).

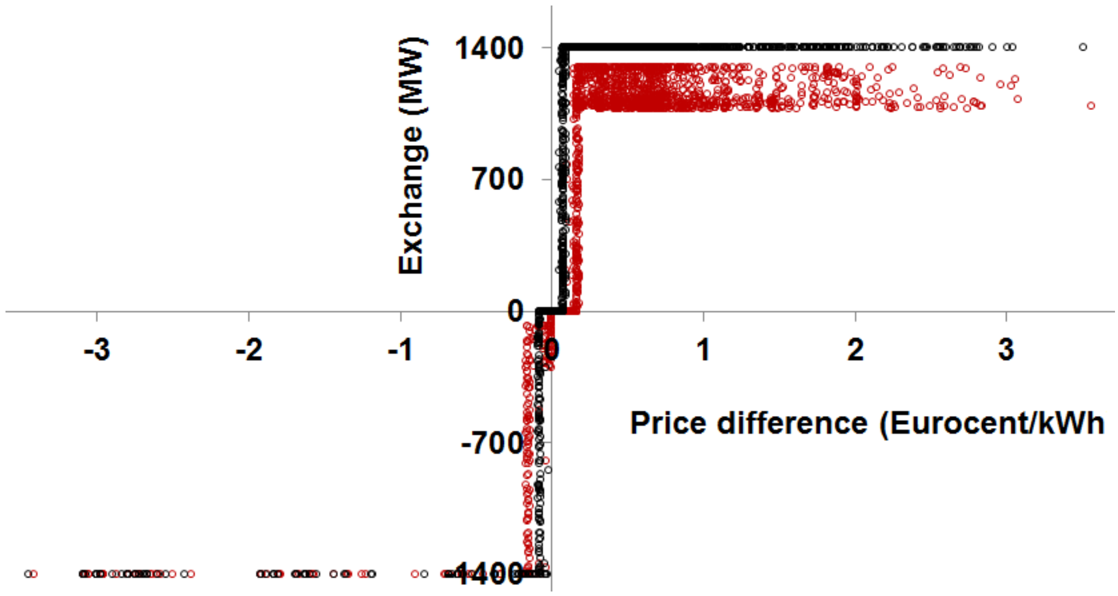


Figure 5.8 **Horizontal axis: Price in GB-NORTH minus price in NOR-VESTMIDT.**
Vertical axis: Net export from Norway to GB on 2nd cable
Black dots: Case B2 (direct connection). Red dots: Case C1 (northern integration)
All simulated cases for climate year 2004

The black dots in the upper right diagram shows a maximum export from Norway to GB on the direct connection when prices are highest on the British side, and vice versa (cf. the black dots on the lower left diagram).

The red dots show that there never is full export from Norway to GB on the 2nd cable if it is connected to the North Sea node. The reason is that a part of the energy that is transmitted from mainland is consumed in the North Sea node. The vertical spread of red dots shows wind-power variability. However, if prices are highest on the Norwegian side, there is full export from British mainland to the North Sea node, which is a part of Norway.

For a single hour, the system cost for integrating the cable with the North Sea node is the price-difference times unused transmission capacity towards GB. Still, it may be profitable to integrate the cable with the North Sea node if the increase in total system costs is less than the saved investment costs because of fewer cable meters.

Figure 5.9 and Figure 5.10 compares simulation results for direct connections and integration with southern North Sea node (area 51) and Doggerbank node (52) respectively. For these cases the connection on British mainland is GB-MID, and there are few occasions of a lower price in GB-MID than in the Norwegian connection area (NOR-SORLAND and NOR-VESTMIDT) respectively.

In the southern North Sea node the electricity consumption is less than the maximum wind-power production (142 MW vs. 250 MW installed effect). In cases where wind-power production exceeds the consumed amount, the export to the GB can be at the maximum 1400 MW. Therefore, only part of the wind-power variability is shown by the spread of red dots in Figure 5.9.

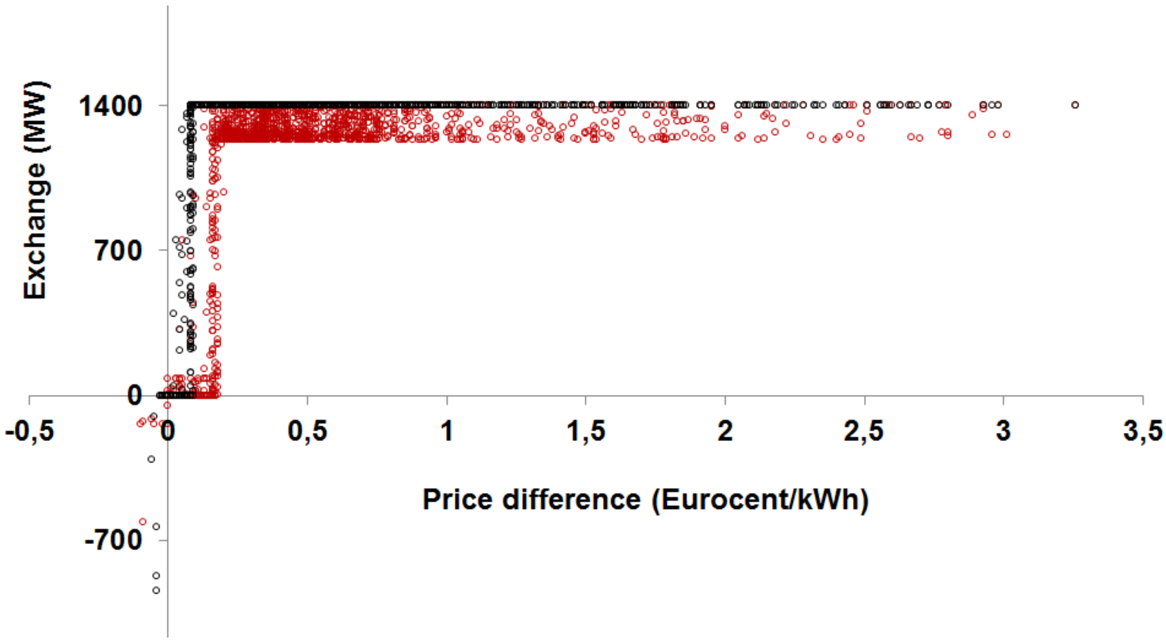


Figure 5.9 Horizontal axis: Price in GB-MID minus price in NOR-SORLAND
Vertical axis: Net export from Norway to GB on 2nd cable
Black dots: Case B3 (direct connection). Red dots: Case C2 (southern integration)
All simulated cases for climate year 2004

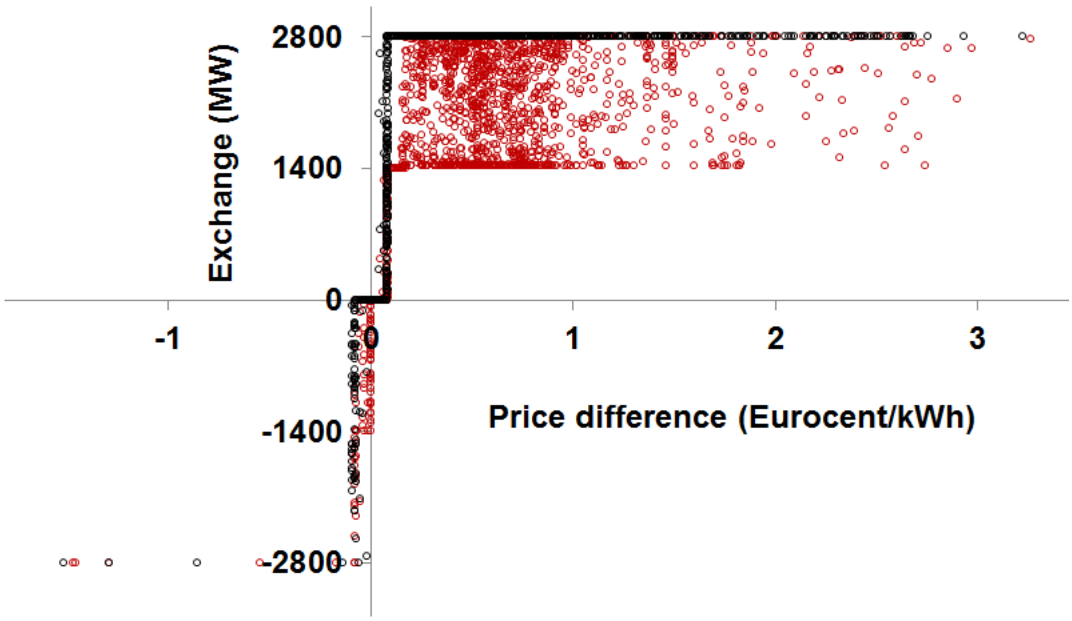


Figure 5.10 Horizontal axis: Price in GB-MID minus price in NOR-VESTSYD
Vertical axis: Net export from Norway to GB on two cables
Black dots: Case A2 (direct connections). Red dots: Case C3 (Doggerbank integration)
All simulated cases for climate year 2004

Instead of modelling two cables between Norway and GB in Case A2, we increased the capacity for the first direct connection. Therefore, we do not have a separate simulation results for the 2nd direct connection. When comparing Case A2 and C3 in Figure 5.10, we have therefore used total exchange between Norway and GB. In Case C3 it is the wind-power production at Doggerbank that blocks for transmission between Norway and GB. As seen from Figure 5.10, wind-power variability is larger for Doggerbank than for Norwegian off-shore nodes because of more wind-power installed.

5.5 Case D1 and D2. Flexible southern transmission

In Case D1 and D2 the southern transmission grid is more flexible. The cable between Norway and GB is connected to the southern North Sea node. In addition, there is third connection to Germany, and in Case D2 the cable is connected to Doggerbank too. Figure 5.11 shows the difference between the southern North Sea grid for case C2 (southern integration), D1 and D2. The annual average transmission to/from the southern North Sea node at Norwegian side is also shown for each case.

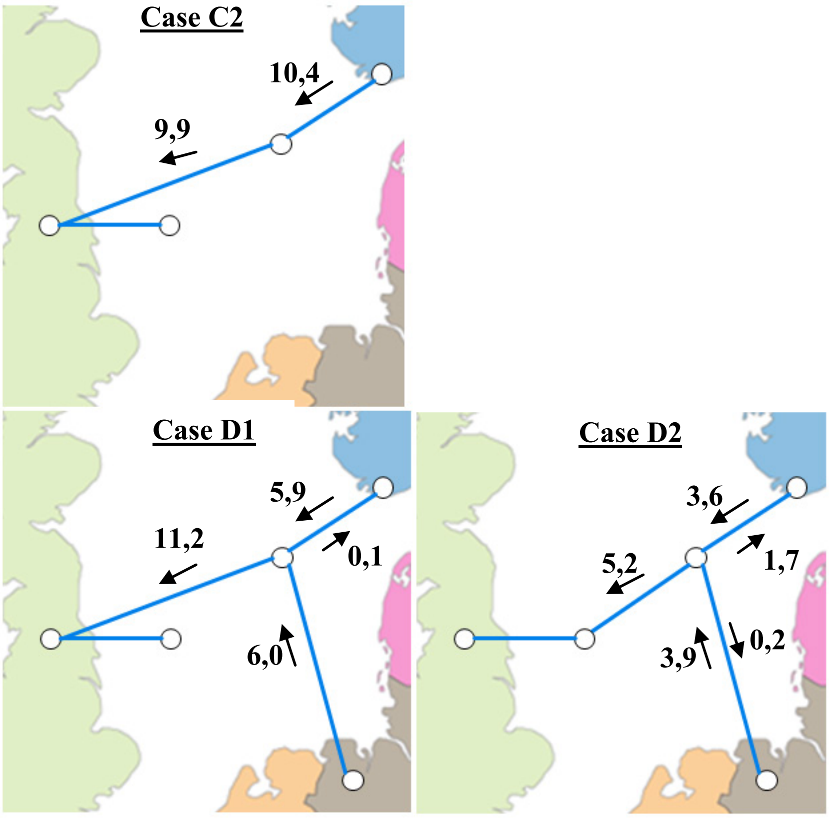


Figure 5.11 Average transmission to/from the southern North Sea node (area 50) in TWh/year

In Case C2, the transmission from Norwegian mainland to the North Sea node is 10,4 TWh on average. In comparison, a 100 % utilization of the 1400 MW cable gives 12,2 TWh. The average net injection (production minus consumption) in the North Sea node is -0,5 TWh, so 9,9 TWh is transmitted to GB mainland.

In Case D1, a 1400 MW connection to northern Germany is included. This has two consequences. Firstly, the export to GB increases slightly because power prices sometimes are lower in northern Germany than in Norway. Secondly, the export towards GB is divided between mainland in Norway and Germany. It is, however, not possible for Norway or Germany to import large quantities from each other because cable capacity on one of the sides is utilized for export to GB. Notice also that all export to GB that goes through the southern North Sea node is Norwegian export in the model since this node is a part of Norway.

In Case D2, the cable is also connected to Doggerbank. This reduces the import potential for GB since wind-power at Doggerbank needs almost the full capacity at maximum production. On the other hand, reduced export to GB allows more trade between mainland in Norway and Germany (there is also a direct connection). The extra trade capacity between Norway and Germany is mostly utilised for import to Norway.

6 Cost-benefit analysis

6.1 Overview

In section 6.2 to 6.4 operating benefits, investment costs and profitability are evaluated for the grid-cases illustrated in Figure 5.1. For those cases where a cable between Norway and GB is connected to a North Sea node, there may however be different degrees of build-in flexibility for the future in the system. These technological details are not represented in our EMPS simulations, but affect investment costs and the cost-benefit analysis. In the following it will be a premise that the applied technology is a highly flexible preparation for the future, i.e. post 2020. Cost and benefits for alternative technological solutions, and for cases where additional wind-power is installed in North Sea nodes, is considered in section 6.5.

6.2 Operating profits

Method

A partial approach for considering the economic benefits of investments in transmission capacity between two areas in a given hour is to multiply the price difference with the capacity of the line. In a competitive market, the operating profits for the investor is determined by the post-investment price-difference between connected areas. The value for society is somewhere between the profits evaluated at price-differences pre and post to the investment. In this study we have a more general approach where the total economic surplus for consumers, producers and transmission system operators in the whole simulated system are calculate for each considered case.

Total operating surplus in the simulated system for all cases is shown in Figure 6.1. The surplus in Case A2 is normalized to zero, while surplus for other cases are relative to Case A2.

Case A1 (one direct connection to GB)

For Case A1 there is a smaller average total economic surplus since there is only one cable between Norway and GB. The difference is 38,2 million euro per year in average. However, this is probably an under-estimate for the value of the 2nd cable since hydropower production is approximately 0,7 TWh larger for Case A1 than for most of the other cases.[5] If the model had been fine-tuned for each case, the average production would also be roughly the same. However, because of the number of cases and the size of model in this project, it has not been possible to fine-tune model calibration for each case. A moderate estimate for the value of the reduced hydropower production from Case A1 to Case A2, using 3 eurocent/kWh, is 21 million euro. When we account for this, the adjusted estimate for the value of the 2nd cable is almost 60 million Euro, which roughly corresponds to 0,5 eurocent/kWh average price-difference between GB-MID and NOR-VESTSYD. In Case A2, the price-difference between GB-MID and NOR-VESTSYD is 0,54 eurocent/kWh.

Case B1 (northern connection in Norway)

In Case B1 there is a different connection point in Norway for the 2nd cable. The connection point is moved from NOR-VESTSYD to NOR-VESTMIDT. This increases average surplus by 20,6 million euro. A main reason for this is that average prices in NOR-VESTMIDT are lower than in NOR-VESTSYD, cf. Figure 5.4, and this increases the benefits of trading with the high-price area GB-MID. One important reason for the relatively higher price in NOR-VESTSYD compared to e.g. NOR-VESTMIDT is that there already is one

[5] Annual hydropower production for Case A1 is 133,1 TWh. For the other A-, B- and C-cases production varies in the interval from 132,3 TWh to 132,5 TWh. For Case D1 and D2, average production is 131,7 and 131,9 TWh respectively.

cable between this area and GB-MID in all our cases, while we consider different connection points for a 2nd cable.

Case B2 (northern connection in Norway and GB)

In Case B2 the GB connection point is also moved northward from GB-MID to GB-NORTH. This increases the average total economic surplus by additional 3,5 million euro to 24,1 million euro. The average price is lower in GB-NORTH, but the variability of the price is higher. In cases where there is a very low price in GB-NORTH because of a lot of wind-power, and congestion towards GB-MID, an extra direct connection from this area to Norway is beneficial. When the wind-power surplus is transferred to Norway, reservoir water can be saved and utilized in other weeks.

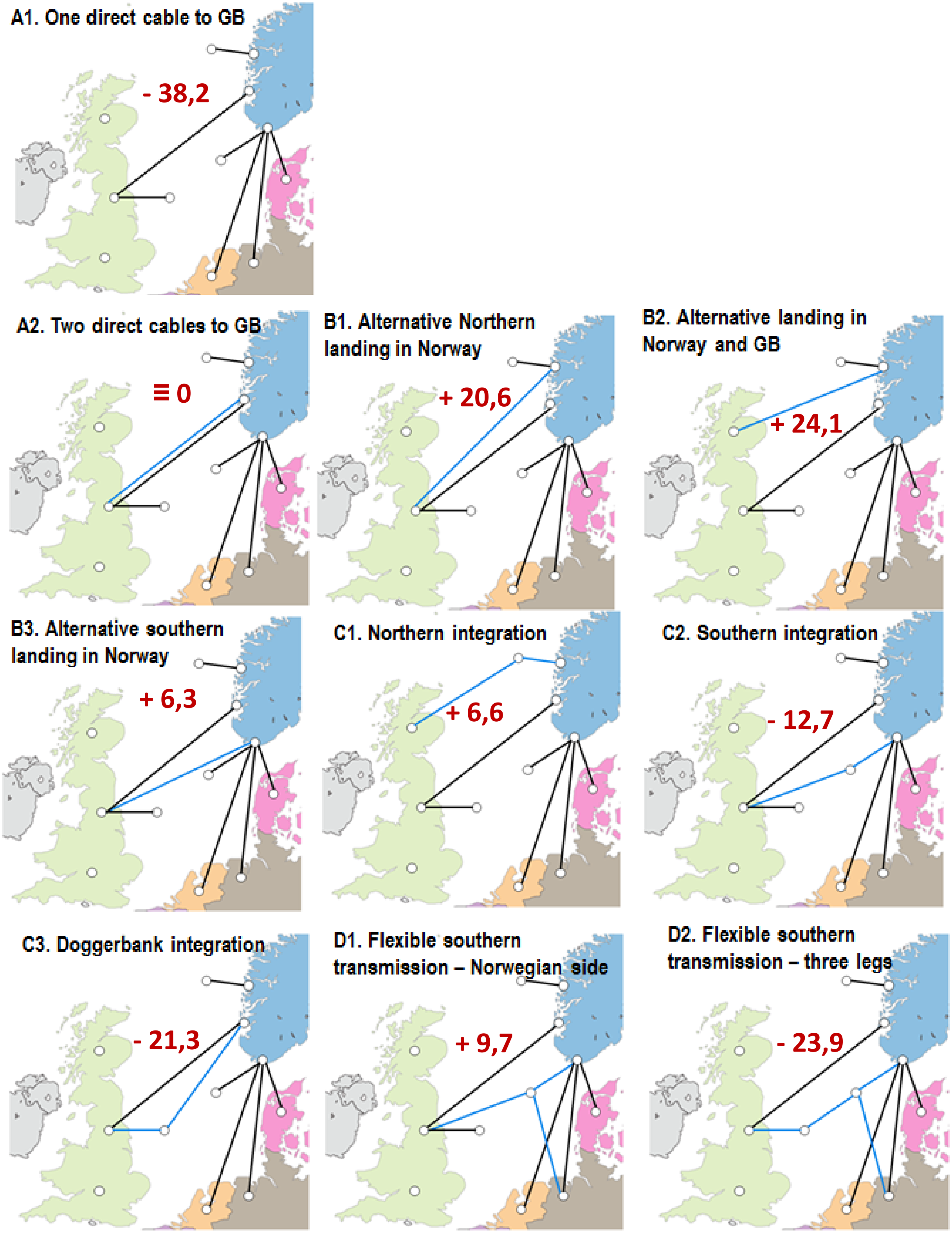


Figure 6.1 Total operating surplus relative to case A2 in M € per year

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Case B3 (southern connection for Norway)
In Case B3, the change compared to Case A2 is that the connection point for the 2nd cable is moved southward to NOR-SORLAND. This area is already well connected to other European countries. In the Basecase, the average power price in NOR-SORLAND is slightly higher than in NOR-VESTSYD, cf. Figure 5.4. Still, there is a slight increase (6,3 million euro) in average total economic surplus by moving the connection point to NOR-SORLAND. One reason for the increased surplus can be that NOR-SORLAND already is connected also to Denmark, Germany and the Netherlands. Thus, the cable between GB-MID and NOR-SORLAND connects markets in GB to the continent more directly than a cable between GB-MID and NOR-VESTSYD. Also, there may be increasing congestion between NOR-VESTSYD and other Norwegian areas when there are two 1400 MW cables between NOR-VESTSYD and GB-MID.

Case C1 (northern integration)
In Case C1, the connection points for Norway and GB are NOR-VESTMID and GB-NORTH. This was also analysed in Case B2. However, in Case C1 the cable is also connected to the northern North Sea node. As a consequence, the export potential to GB is reduced, cf. Figure 5.8. The average total economic surplus in Case C1 is 17,5 million euro lower than in Case B2. For 2004, which is illustrated in Figure 5.8, the lost income because of less than full utilization of the transmission capacity between Norway and GB is 13,7 million euro evaluated partially at prices in Case C1.

Case C2 (southern integration)
In Case C2, the connection points for Norway and GB are NOR-SORLAND and GB-MID. This was also analysed in Case B3. However, in Case C1 the cable is also connected to the southern North Sea node. This gives reduced export potential to GB, cf. Figure 5.9. Compared to Case B3, the total economic surplus is reduced by 19 million euro. The cost of southern integration is therefore higher than the cost of northern integration, even though southern integration has less effect on the export potential to the GB. We have not studied the reason for this. A possible explanation can be that average prices GB-MID are higher than in GB-NORTH, so that export towards GB-MID is more profitable. Also, at occasions of low prices because of high wind-power production in GB-NORTH, maximum export from GB to Norway is possible also when the cable is connected to the North Sea node (which is Norwegian).

Case C3 (Doggerbank integration)
In Case C3, the connection points for the 2nd cable are NOR-VESTSYD and GB-MID respectively in Norway and GB. This was also analysed in Case A2. However, in Case C3 the cable is also connected to the wind-power node DOGGERBANK. The installed wind-power capacity at DOGGERBANK coincides with the assumed transmission capacity from DOGGERBANK to shore (1500 MW). Consequently, the export capacity from Norway to GB is reduced by 1 MW for each MW wind-power produced at DOGGERBANK. The total system costs of the reduced export potential, which also is displayed in Figure 5.10, is 21,3 million euro per year in our simulations.

Case D1 (flexible southern transmission – Norwegian side)
In Case D1 we take Case C2 (southern integration) as the starting point, and then we evaluate the gain of adding a connection to Germany, cf. Figure 6.1. One motivation for carrying out this case was basically it allows the North Sea wind-power to be transmitted to the area that have the highest price in each simulated period. However, the cable also allows for additional transmission between Germany and GB or Norway mainland. This extra option will have an economic value, and in our simulations the total economic gain of the extra connection to Germany is 9,7 – (-12,7) = 22,4 million euro. The relatively high value is mostly caused by the extra cable capacity between GB and northern Germany. In northern Germany, power prices are occasionally low because of large amounts of wind-power. The extra cable capacity to GB is therefore valuable. We have not studied the effects of an extra direct connection e.g. between GB and Germany.

Case D2 (flexible southern transmission – three legs)
Case D2 is the most integrated case for the North Sea grid, cf. Figure 6.1. The cable between Norway and GB is connected both to the North Sea node at Norwegian side and to Doggerbank. In addition, there is a third connection from the North Sea node at Norwegian side to Germany. We have already estimated the cost of connecting the cable to Doggerbank in Case C3. The lost option for transmission to GB is increased further when the transmission can come either from Norway or Germany. If we take Case D1 as the starting point, the cost of also connecting the cable to Doggerbank is 9,7 – (-23,9) =33,6 million euro.

Breakdown of surplus – discussion of some effects
The breakdown to consumers, producers and TSOs for different countries and in total is shown in Table 6.1. The columns under "All" shows values for the whole simulated system, and not the sum for Norway and GB.

Table 6.1 Breakdown of economic surplus in different cases relative to Case A2 (in average M € per year)

	Norway				GB				All			
	Cons	Prod	TSO	Total	Cons	Prod	TSO	Total	Cons	Prod	TSO	Total
A1	310,6	-280,8	-27,9	1,9	-58,3	49,8	-4,9	-13,4	691,6	-779,4	49,6	-38,2
A2	0	0	0	0	0	0	0	0	0	0	0	0
B1	-27,3	36,9	-18,0	-8,4	1,7	-1,4	14,0	14,4	-58,4	79,6	-0,6	20,6
B2	35,4	-33,6	-13,7	-11,8	-37,4	86,8	-16,9	32,5	42,5	0,2	-18,6	24,1
B3	104,7	-79,6	-1,4	23,7	67,0	-54,9	-3,5	8,6	187,4	-170,7	-10,3	6,3
C1	58,7	-69,8	20,0	9,0	-49,1	99,6	-51,4	-0,9	100,1	-82,2	-11,3	6,6
C2	101,8	-88,9	3,5	16,4	55,0	-44,9	-21,3	-11,2	177,6	-175,4	-15,0	-12,7
C3	110,2	-98,1	-29,4	-17,3	-42,8	2,9	45,7	5,9	206,5	-268,3	40,5	-21,3
D1	136,2	-160,6	31,3	6,9	74,7	-61,5	-2,4	10,7	234,5	-155,1	-69,7	9,7
D2	203,7	-208,5	6,1	1,2	-13,4	-48,9	65,0	2,7	392,9	-414,0	-2,8	-23,9

The extra direct connection between Norway and GB (A1 vs. A2) leads to higher prices in Norway and lower prices in GB. In Norway, this gives lower consumer surplus and higher producer surplus. The effect is opposite in GB. The extra export to GB also affects prices in other countries, e.g. in the other Nordic countries, and this leads to lower consumer surplus and higher producer surplus.

When the cable is moved to NOR-VESTMIDT, cf. Case B1, the income to TSOs on the cable is increased because of larger price-difference between connected areas. However, for Norway this gives a reduced income to the TSO since it got the whole income from congestion between NOR-VESTSYD and NOR-VESTMIDT in Case A2, while the income from congestion on the 2nd cable by assumption is split between the TSOs in Norway and GB. Actually, this effect is so strong that it makes Case A2 better for Norway than Case B1. There are similar results for other cases. This clearly illustrates that a pan-European transmission expansion planning framework is needed to incentivize projects that are cost-efficient from a system-perspective.

Electricity prices are lower in GB-NORTH than in GB-MID. Therefore, Norwegian consumer surplus is higher in B2 than in B1. The effect is opposite for Norwegian producers. For GB, there is fewer occasions of low prices in GB-NORTH in Case B2 because of high wind-power production. This gives increased profits for producers, and reduced surplus for consumers.

For Norwegian consumers and producers, all C- and D-cases give a surplus between the surplus of Case A1 and Case A2. The reason is that the transmission between Norway and GB is larger than in Case A1 because of the extra cable, but less than in Case A2 where there are two direct connections. The price-increase in Norway is therefore between those two cases. Results are more complex for the GB. The reason is probably that cases of southern integration connect GB better to the continent through NOR-SORLAND or North Sea nodes. For instance, the relative high consumer surplus in the GB in case D1 is probably caused by low-priced imports from northern Germany via the Norwegian North Sea node. In Case D2 this import is blocked by wind-power production at Doggerbank, and therefore Norwegian consumers benefits relatively more from occasions of low prices in northern Germany.

6.3 Investment costs

Costs for cables and auxiliary equipment

Investment cost of power cables and auxiliary equipment are considered in [22].[6] Cost-data that are shown in Table 6.2 are based on the premise that both cables and converter stations are built in whole units. The block capacity implemented is 600 MW. Multiple blocks can be built. In this case, each new block incurs the full fixed cost defined. Offshore nodes and onshore nodes here considered assuming flexible VSC technology.

As mentioned in Section 6.1, the assumed infrastructure for cases where the North Sea node is connected to a cable between Norway and GB is actually a preparation for further wind-power developments after 2020. All costs for North Sea node equipment is therefore scaled proportionally from 600 MW to 1400 MW capacity, even though the installed wind-power in the Norwegian North Sea nodes are far less in our cases. Additional offshore wind-power can therefore be included in the system in a later year without major changes in the system. Also, the setup of breakers and switchgears makes a flexible and robustsystem. We call this system-setting “Flexible setup”.

Table 6.2 Cost data for 600 MW block capacity

Component	Cost	Unit
β (DC breaker cost factor)	3	M€
Cable cost per km	0,76	M€/km
Cable, fixed	5	M€
Onshore converter	125,3	M€
Onshore DC breaker and gear	45,4	M€
Onshore AC breaker and gear	10,8	M€
Offshore converter and platform	156,4	M€
Offshore DC breaker and gear	55,7	M€
Offshore AC breaker and gear	10,8	M€
Offshore T-junction	10,8[7]	M€
Onshore converter station with AC-side breaker	136,1	M€
Offshore converter station with AC-side breaker	167,2	M€

[6] Assumptions on cost data for cables, converter stations, switchgear and offshore platforms are used as provided in the WINDSPEED Deliverable D2.2 “Inventory of location specific wind energy cost” by partner GL Garrad Hassan of the WINDSPEED consortium

[7] Our guessimate based on OffshoreGrid-project presentations

Costs for cable-alternatives and cases

Figure 6.2 is a principle drawing that gives a full overview of the cable-alternatives we have considered. See Appendix C for our assumptions regarding the exact geographical locations of connection points. Note that area 50 is located on the northern direct connection between Norway and GB in final cost-calculation, i.e. further south than indicated in the figure. Table 6.3 shows cable length and investment costs for each cable.

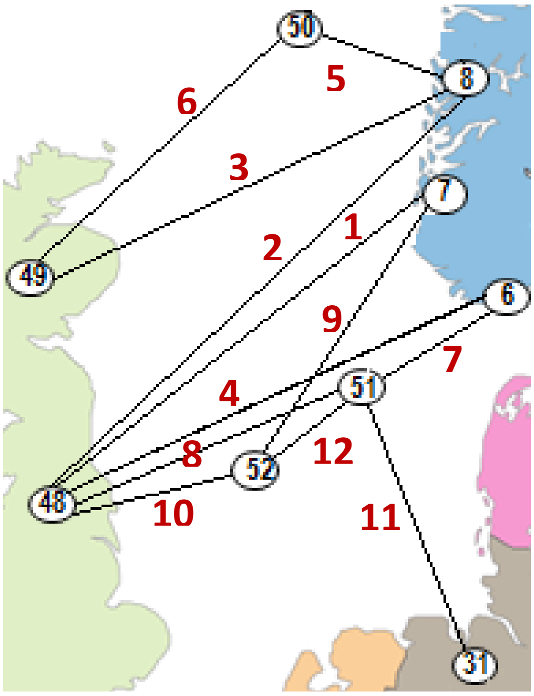

Figure 6.2 Cable alternatives

Table 6.3 Investment costs for North Sea HVDC cables (in M €)

Cable	Length [km]	Total	
1	713	1911	
2	855	2163	
3	607	1725	
4	636	1775	
5	99	730	*)
6	634	1360	
7	236	973	*)
8	409	1185	
9	547	1429	
10	280	1452	
11	442	1243	
12	204	634	

*) Additional cost for 1400 MW cable and components, compared to a 250 MW direct connection from wind-park to shore.

The cost for cable 1 is calculated as follows:

$$\left(713\ km\ \times 0{,}76\frac{M€}{km} + 5\ M€ + 2 \times 125{,}3\ M€ + 2 \times 10{,}8\ M€\right) \times \frac{1400\ MW}{600\ MW} = 1911\ M€ \qquad (6.1)$$

The distances are based on straight lines between each pair of locations using the Great Circle calculator [23]. This gives a consistent but somewhat optimistic cable length estimate. In cases where the 2nd cable between Norway and the GB is connected to a Norwegian North Sea node, the cable replaces direct connections (a) from a wind-farm to shore, and (b) from a petroleum installation to shore. In cases of North Sea integration, the investment costs for these smaller cables are subtracted from the total investment cost so that the total investment costs is less than the sum of corresponding cables in Table 6.4. The connection between DOGGERBANK and GB-MID is 1500 MW in all cases. Further details about the calculation of costs for line-segments and corresponding equipment, and the aggregation into cases are provided in Appendix D.

Table 6.4 Investment costs for North Sea HVDC cables for each case (in M €)

Case	Cables	Cost
A1		0
A2	1	1911
B1	2	2163
B2	3	1723
B3	4	1775
C1	5, 6	1930 *)
C2	7, 8	1954 *)
C3	9	1429
D1	7, 8, 11	3197 *)
D2	7, 11, 12	2646 *)

*) Includes saved costs of not investing in direct connections from off-shore wind parks and petroleum installations to shore.

6.4 Cost-benefit

In the following we will compare annual operating profits for different alternatives with annualized investment costs. An example of how investment costs are transformed to yearly values, using 5 % interest rate and 40 years economic life, is shown in equation (6.2). We assume that the annual payment is done at the end of each year. The 2646M€ investment costs corresponds to 154,2M€ per year in 40 years.

$$\frac{2646M€ \times 0{,}05}{1 - \left(\frac{1}{1+0.05}\right)^{40}} = 154{,}2M€ \qquad (6.2)$$

Table 6.5 shows operating profits for different cases relative to Case A2, cf. Section 6.2, and annualized investment costs for each case at 4 interest rate alternatives. Operating profits for Case A1 is adjusted to account for the value of a different hydropower production in this case. For the integrated cases C1 and C2, Table 6.5 shows results for flexible setup. Cost-benefit for alternative settings are discussed in Section 6.5.

Table 6.5 Investment costs for North Sea HVDC cables for each case (in M € per year)

Case	Operating profits	Annualized investment costs*)				Total profit	
		1 %	3 %	5 %	7 %	3 %	5 %
A1	-60**)	-58,2	-82,7	-111,4	-143,3	22,7	51,4
A2	0	0,0	0,0	0,0	0,0	0,0	0,0
B1	20,6	7,7	10,9	14,7	18,9	9,7	5,9
B2	24,1	-5,7	-8,1	-11,0	-14,1	32,2	35,1
B3	6,3	-4,1	-5,9	-7,9	-10,2	12,2	14,2
C1	6,6	0,6	0,8	1,1	1,4	5,8	5,5
C2	-12,7	1,3	1,9	2,5	3,2	-14,6	-15,2
C3	-21,3	-14,7	-20,9	-28,1	-36,2	-0,4	6,8
D1	9,7	39,2	55,6	74,9	96,5	-45,9	-65,2
D2	-23,9	22,4	31,8	42,8	55,1	-55,7	-66,7

*) 40 years in operation, zero rest-value after 40 years
**) Adjusted value, cf. Section 6.2.

A positive value in Table 6.5 means that the corresponding operating profit or investment cost is larger than in Case A2 (two direct cables between NOR-VESTSYD and GB-MID).

Case A1 (one direct connection)
Case A1 shows saved investment costs and lost operating profits if only one direct connection to the GB is included. At 1 % interest rate, the saved investment cost is slightly less than the lost operating profits if only one cable is built. For higher interest rates the saved investment cost is higher. It is therefore not profitable to build an extra direct connection between NOR-VESTSYD and GB-MID.

Alternative connection points (B1-B3)
All cases of alternative connection points for Norway and the GB gives an increased operating profit compared to Case A2. For Case B2 (northern connection for Norway and GB) and B3 (southern connection point for Norway) there are also lower investment costs than in Case A2. For a 2nd direct connection, Case B2 gives the best economic result for a 2nd cable when both operating surplus and investment costs are accounted for. Case B2 is also the only alternative where a 2nd cable is profitable at a 3 % interest rate, i.e. the total profit is larger than for Case A1 (32,2 vs. 22,7). At 5 % interest rate, Case A1 is the most profitable alternative.

Cable connected to North Sea nodes (C1-C3)
The integrated cases use flexible technology that may serve up to 1400 MW wind-power offshore. Compared to the corresponding direct connections (C1 vs. B2, C2 vs. B3 and C3 vs. A2), operating benefits are reduced for the 2nd cable because of reduced transmission flexibility. For the two former cases, investment costs go up because of the extra electrical equipment needed. However, for Case C3 investment costs is reduced because saved cable meters from Doggerbank to GB is 1400 MW capacity, and because converter station and AC-breaker for 1500 MW capacity already is included on the onshore connection point for the

Doggerbank cable. The Doggerbank integration alternative is more profitable than a direct connection from NOR-VESTSYD to GB at 5 % interest rate, even though the operating surplus is considerable lower.

Flexible transmission (D1 and D2)
In Case D1 there are excessive investment costs compared to Case A2, while the extra profits are much less. An extra connection to Germany in Case D1 gives additional benefits compared to the southern integration in Case C2, but the increase in investment costs is a lot larger. In Case D2, some investment costs are saved compared to Case D1 because of fewer cable meters on British side, but operating benefits are reduced even more because wind-power production at Doggerbank blocks for import to GB.

6.5 Alternative technological solutions, and wind-power cases

Technology cases
In this report we consider 3 different technological solutions for connecting a Norwegian North Sea node with a cable between Norway and GB, i.e. for cases described in C1 and C2: "Flexible setup", "Fewer DC-breakers" and "T-Junction". The "Flexible setup"-solution was described in Section 6.3. For this technology, only Doggerbank integration was profitable relative to the corresponding direct connection. In this section we evaluate if integration can be profitable also on the Norwegians side if less costly technologies are applied. Two alternative technological solutions are described below:

The only difference between "Flexible setup" and "Fewer DC-breakers" is that there are fewer breakers and switchgears in the system in the latter. See Appendix D for additional details. Fewer breakers and switchgears give reduced costs, while the reliability for the overall system is better for "Flexible setup". In the "T-junction" alternative the infrastructure is optimized for the 2020 case. Therefore, costs are lower than for the two other cases. However, the system is not flexible, and additional wind-power cannot be connected to the offshore nodes without major changes and investment costs. Table 6.6 shows investment costs for the different technological setups we have considered. For "Flexible setup" numbers are the same as in Table 6.4.

Table 6.6 Investment costs for North Sea HVDC cables for case C1 and C2 (in M €)

No.	Technology	Case C1	Case C2
1	Flexible setup	1930	1954
2	Fewer DC-breakers	1777	1801
3	T-junction	1642	1659
4	1400 MW wind	1736	1629
5	T-junction + 1400 MW wind	1397	1313

Wind-power cases
We have also considered cases where the amount of wind-power installed in the North Sea is larger than reported in Chapter 3. When the installed wind-power capacity is higher, the cost of a direct connection is higher too. Therefore, there are additional avoided costs for integrated solutions. Also, the operation of the system is affected when more wind-power is installed. The operational results for wind-power cases are described in more detail in Chapter 7.

Table 6.7 shows the profitability for case C1 and C2 for combinations of applied technologies and amount of wind-power installed in North Sea nodes. Each case is compared with the corresponding direct connection. In the calculation of annual cost values, we have utilized 5 % interest rate.

Table 6.7 Operating benefits, investment costs and profitability for integrated cases relative to corresponding direct connection. All costs in (in M € per year)

Case	Connection technology	Operation	Investment	Total
250 MW wind, northern connection				
B2	None	-	-	-
C1	Flexible setup for 1400 MW	-17,5	12,0	-29,5
C1_B	Fewer breakers and switchgears	-17,5	3,1	-20,6
C1_T	T-junction	-17,5	-4,7	-12,8
1000 MW wind, northern connection				
B2_V	None	-	-	-
C1_V	Flexible setup for 1400 MW	-13,0	0,7	-13,7
C1_BV	Fewer breakers and switchgears	-13,0	-12,2	-0,8
C1_TV	T-junction	-13,0	-18,9	5,9
250 MW wind, southern connection				
B3	None	-	-	-
C2	Flexible setup for 1400 MW	-19,0	10,4	-29,4
C2_B	Fewer breakers and switchgears	-19,0	1,5	-20,5
C2_T	T-junction	-19,0	-7,7	-11,3
1000 MW wind, southern connection				
B3_V	None	-	-	-
C2_V	Flexible setup for 1400 MW	-9,0	-8,4	-0,6
C2_BV	Fewer breakers and switchgears	-9,0	-21,4	12,4
C2_TV	T-junction	-9,0	-26,8	17,8

As shown in Table 6.7, it can be profitable to connect the cable to a North Sea node if additional wind-power is installed. Firstly, the reduction in operating profits because of the integration is reduced when additional wind-power is connected. When additional wind-power is added, the North Sea nodes become net production nodes, which allows for full utilization of the cable towards GB. Secondly, additional wind-power requires higher capacity from wind-farms to shore in case of direct connections only. The avoided costs in integrated setups are therefore higher.

Unless additional wind-power is installed, the direct connections are more profitable than integrated solutions. However, if 1000 MW wind-power is installed and the T-junction technology is applied, then the integrated solutions are more profitable than direct connections. Benefits of having flexibility post 2020 is not dealt with in this study.

7 Extra cases to study important uncertainties

7.1 Overview

Additional cases are simulated to analyse the effect of changing some assumptions. For each case we study the effect on variables such as prices, production, transmission or the profitability of North Sea grid alternatives. Table 7.1 gives a full overview of the simulated cases.

Some grid configuration cases are carried out under alternative assumptions regarding the amount of installed wind-power in the North Sea (no 11 – no 15), and cases of no nuclear power generation in Germany (no 16 – no 18, and no 20. In addition we study the effect of a different assumption for exchange towards countries on the outside of the simulated system (no 19 and 20). The economic results for case no. 11 – 14 have already been presented in Table 6.7.

Table 7.1 Extra cases to study important uncertainties

No	Case	Short description
Extra wind-power cases		
11	B2_V	B2 + extra wind-power production in North Sea nodes
12	B3_V	B3 + extra wind-power production in North Sea nodes
13	C1_V	C1 + extra wind-power production in North Sea nodes
14	C2_V	C2 + extra wind-power production in North Sea nodes
15	D1_V	D1 + extra wind-power production in North Sea nodes
No German nuclear cases		
16	A2_A	A2, but no nuclear power in Germany
17	C2_A	C2, but no nuclear power in Germany
.18	D1_A	D1, but no nuclear power in Germany
Zero exchange cases		
19	A2_G	A2, but no exchange to exogenous countries
20	A2_GA	A2, but no exchange to exogenous countries and no nuclear power in Germany

7.2 Extra wind-power cases

In Case no 11 – no 15 we study the effect of increasing maximum wind-power production to 1000 MW in the two North Sea nodes on the Norwegian side. This corresponds to increasing the installed capacity to roughly 1100 MW. Table 7.2 shows the changed balance for the simulated system when the extra wind-power capacity is installed. Case B2_V is compared with Case A2.

Wind-power production in the North Sea increases by 6,5 TWh annually on average. To balance this, Coal-power production is reduced by 5,2 TWh, while net export to exogenous countries increases by 1,7 TWh. Gas-power production in the GB is increased by 0,8 TWh. We have not studied why this occur. One possibility is that varying renewable generation gives gas-power an advantage over coal-power because of higher start-up costs for coal power.

Table 7.2 Changed balance in the simulated system when the installed wind-power capacity in the North Sea increases by 2000 MW (Case B2_V vs. Case A2)

Available			Use	
Wind-power North Sea		+6,5	Net export	+1,7
Coal power		–5,2	Gross consumption	+0,3
Germany	*–2,0*			
GB	*–1,5*			
Finland	*–0,9*			
Denmark	*–0,5*			
Netherlands	*–0,2*			
Gas-power		+0,3		
GB	*+0,8*			
Other	*–0,5*			
Other		+0,3		
Total available		+2,0	Total use	+2,0

Figure 7.1 shows the cross-plot between price-difference in Norway and GB and the corresponding exchange on the 2nd cable for two cases with extra wind-power capacity in North Sea nodes: northern direct connection (Case B2_V) vs. northern connection and North Sea node integration (Case C1_V).

If there is a direct connection, the full capacity is utilized in the direction where the price is highest (black dots). However, if the cable is integrated with the northern North Sea node, the exchange is affected by wind-power production. In case the price is highest in the GB, cf. the upper right quadrant, there is export to the GB. However, even in the case of maximum 1000 MW wind-power production in the northern North Sea node, there are occurrences where wind-power production is below consumption (300 MW). In such cases, a part of the 1400 MW export from Norway mainland towards GB is consumed in the North Sea node, and the export is reduced correspondingly. See Figure 3.2 for a probability distribution for wind-power production at 250 MW installed capacity.

In case the price is highest in Norway, there is export towards Norway, cf. the lower left quadrant. If wind-power production is less than then consumption in the North Sea node, the export from GB to Norway (to North Sea node) is at the maximum 1400 MW. However, if the wind-power production exceeds electricity consumption in the North Sea node, this reduces the export potential from the British side since the cable to Norwegian mainland is congested. Therefore, the variability of the red dots in the lower left quadrant show the variability of wind-power production above 300 MW.

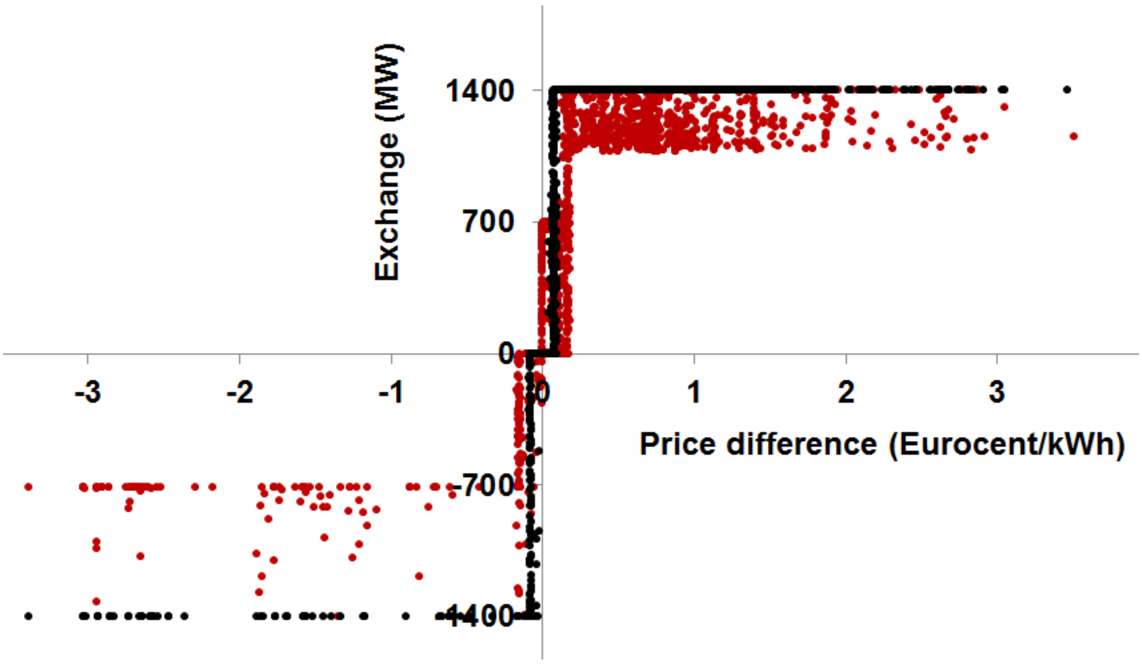

Figure 7.1 Horizontal axis: Price in GB-NORTH minus price in NOR-VESTMIDT
Vertical axis: Net export from Norway to GB on 2nd cable
Black dots: Case B2_V (direct connection). Red dots: Case C1_V (northern integration)
All simulated cases for climate year 2004.

The purpose of Table 7.3 is to clarify how the size of the installed capacity for wind-power capacity in North Sea nodes affects the consequence of integrating a 2nd cable between Norway and GB with a these nodes. We focus on average annual transmission in each direction, and on total economic surplus.

In the first block, labelled (a), we show consequences of northern North Sea integration without the extra wind-power capacity. On average, the integrated case gives 1,6 TWh less export towards GB, while total economic surplus is reduced by 17 M € per year on average.

The second block, labelled (b), shows results for the same North Sea grid cases, but with extra wind-power capacity installed in the North Sea. The reduction in export towards GB because of North Sea node integration for 2nd cable is 0,7 TWh this case, compared to 1,6 TWh in block (a). Thus, the effect on export is damped when there is extra wind-power installed in the North Sea. The reason is of course that there are fewer occasions of wind-power production below the consumed amount (300 MW) in the North Sea node when extra wind-power is installed. On the other hand, there is a slight reduction in the export from GB towards Norway when more wind-power is installed. The reduction in total economic surplus because of North Sea node integration is reduced from 17 M € to 13 M € per year when additional wind-power capacity is installed.

Table 7.3 Effects of connecting 2nd cable to off-shore node. Changes in: Transmission to/from GB (average TWh/year), and total economic surplus (M € per year)

	Transmission on 2nd cable		Total surplus	Cases
	NO - GB	GB – NO		
(a) Effect of northern integration				
C1	6,3	0,7	570070	Northern integration
B2	7,9	0,8	570087	Direct connection, northern
Diff	-1,6	-0,1	-17	
(b) Effect of northern integration, extra wind-power				
C1_V	7,8	0,3	570306	C1 + extra wind-power
B2_V	8,5	0,6	570319	B2 + extra wind-power
Diff	-0,7	-0,3	-13	
(c) Effect of southern integration				
C2	9,9	-	570050	Southern integration
D1	11,2	-	570073	Flexible southern transmission
B3	11,2	-	570069	Direct connection, southern
Diff C2	-1,3	-	-19	
Diff D1	-	-	4	
(d) Effect of southern integration, extra wind-power				
C2_V	10,8	-	570290	C2 + extra wind-power
D1_V	11,5	-	570305	D1 + extra wind-power
B3_V	11,5	-	570299	B3 + extra wind-power
Diff C2_V	-0,7	-	-9	
Diff D1_V	-	-	6	

In block (c) and (d) we do the same comparison for southern integration. However, here we compare results for a direct connection both with North Sea node integration and with a more integrated case that includes a connection to Germany. First we discuss results for North Sea node integration without the extra connection to Germany.

Block (c) shows that the southern North Sea node integration reduces the export towards GB by 1,3 TWh annually, and this gives a 19 M € reduction in total economic surplus. However, if extra wind-power is installed in the southern North Sea node, cf. block (d), export towards GB is reduced by 0,7 TWh. The total economic cost of integrating the 2nd cable with the southern North Sea node is reduced from 19 M € to 9 M € per year when additional wind-power is installed.

In the integrated cases that include a connection to Germany, the average export to GB is not reduced compared to the case of a direct connection. The reason is that the export towards GB in a given time-step can come from either Germany or Norway or a combination. Figure 5.11 shows that about half of the export towards GB comes from Norwegian mainland, while the other half comes from Germany. However, since the North Sea node is a Norwegian node in our model, transmission from Germany is import to Norway, while all export to GB on cable is export from Norway. At least this is the accounting system in the model. If markets will be organised in this manner is not dealt with here. Possibly, this can have some consequences for the division of trading surplus.

An integrated grid with the extra connection to Germany gives a larger economic surplus than a direct connection. The additional surplus compared to the case of direct connection is increased slightly from 4 M € vs. 6 M € per year when extra wind-power is installed.

7.3 No German nuclear power cases

After the tragedy of Fukushima, the German government decided to shut down all nuclear power plants by 2022. The tragedy occurred during our study, and it was not possible for us make new assumptions for all cases. Also, it remains to be seen how much nuclear power that actually will be shut down. We have, however, studied effects of a total phase-out of German nuclear power in extra cases. Table 7.4 shows the change in the annual energy balance for each country. Numbers are results for Case A2_A scenario minus results for Case A2.

Table 7.4 Change in average annual energy balances for 2020 in case of no nuclear power production in Germany (in TWh)

	Norway	Sweden	Denmark	Finland	GB	Germany	Netherlands	Belgium	Total
Gross consumption	-0,2				-0,1		-0,1		-0,4
Export	-1,3	-1,5	1,0	0,7	0,1	-48,5	-3,1	-0,2	-52,8
Total use	-1,6	-1,4	1,0	0,7	0,1	-48,5	-3,2	-0,3	-53,3
Hydro	0,2	-0,1		-0,1					0,1
Wind									
Bio		0,1	0,6	0,3		2,9	0,3	0,3	4,5
Coal			1,8	1,4	2,9	42,2	1,9		50,3
Gas	0,1		0,5		0,9	2,3	9,5	2,6	15,8
Oil									
Nuclear						-134,8			-134,8
Other									
Total generation	0,3	0,1	2,9	1,7	3,8	-87,4	11,7	2,9	-64,1
Import	-1,8	-1,5	-1,9	-1,0	-3,7	38,9	-14,9	-3,1	10,8
Curtailment									
Total available	-1,6	-1,5	1,0	0,7	0,1	-48,5	-3,2	-0,3	-53,3
Net export	0,5	0,1	2,9	1,7	3,9	-87,4	11,8	2,9	-63,6
RES-E	0,2	0,1	0,6	0,2		2,9	0,3	0,3	4,6

For Germany, nuclear power production is reduced by 134,8 TWh per year. In Germany this is mainly balanced by increased coal-power production (42,2 TWh), increased import (38,9 TWh), and decreased export (48,5 TWh). The largest change for other countries that are modelled is a 9,5 TWh increase in Dutch gas-power production. However, almost 64 TWh of the extra net import to Germany comes from the outside of the simulated system, including France, Switzerland, Austria, Czech Republic and Poland.

The effect on average power prices are moderate, cf. Figure 7.2. The reason is that electricity prices on the system boundary in our simulations are fixed at the price of new gas-power production (4,4 Eurocent/kWh) during daytime, and to average coal-power production (3,9 Eurocent/kWh) at night and in week-ends, cf. Section 3.7. Thus, if there is available import capacity, extra electricity can be imported at moderate costs.

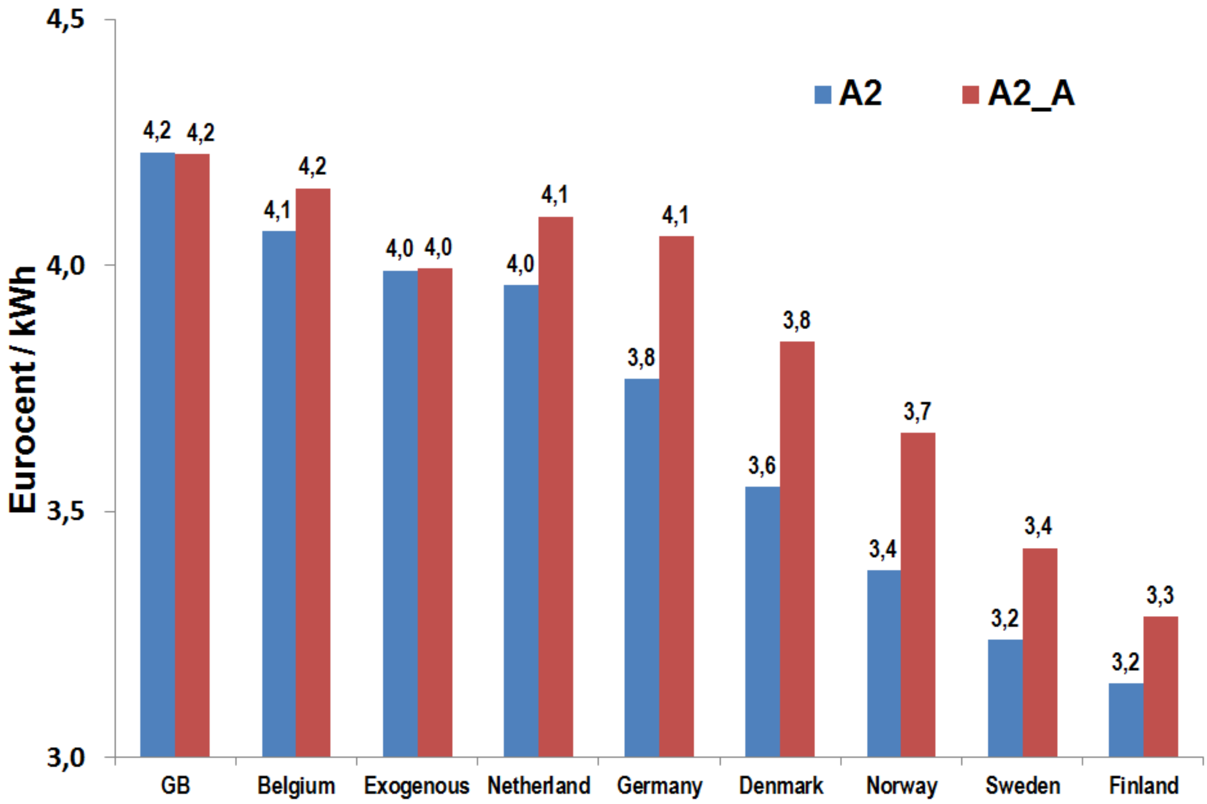

Figure 7.2 Average electricity prices in Case A2 and Case A2_A (no nuclear in Germany)

Table 7.5 shows the gains of adding an extra connection to Germany in the case where a 2nd cable between Norway and GB is integrated with the southern North Sea node. Results are shown for cases both with and without nuclear power production in Germany. The benefit of adding the extra connection to Germany is decreased from 22 to 15 M € per year on average if there is no nuclear power generation in Germany. The reason is that the differences in power-prices in GB and Germany have been reduced after the phase-out of nuclear power.

Table 7.5 Benefits of adding a connection to Germany (in M € per year)

Nuclear in Germany		No German nuclear	
Case	Total surplus	Case	Total surplus
D1	570073	D1_A	565841
C2	570050	C2_A	565856
Diff	22	Diff	15

7.4 Zero exchange cases

Discussing border exchange assumptions
In this study we have modelled trade on the system boundary at fixed prices and limited capacity. The motivation for this flexible modelling is that trade on the system boundary will be affected by the variability of renewable power generation. If there e.g. is extra wind-power generation in a given simulated time-step, it is reasonable to assume that the export to non-modelled countries will increase too.

It is, however, possible that the implemented fixed-price at the border has given too large flexibility. This is indicated by the relatively small price-consequence and high additional net import in the case of no nuclear power production in Germany. The flexibility for trade on system boundary may have dampened price-variation caused by varying wind- and solar-power combined with start-up costs for thermal power generation also in other cases.

Zero exchange (Case A2_G)
In the following we show results for a case where there is zero trade on the system boundary, except towards France. Trade capacity towards France is set to the annual net import in Case A1, divided by 8760 (number of hours in a year). In theory it is therefore possible to import the same amount annually from France. Still, the possibility to import electricity at a moderate cost at the system boundary is greatly reduced.

Figure 7.3 shows all simulated power prices for a German area in climate year 2004. Each dot represents the simulated price for the same time-step in these two cases. In general, price fluctuations have increased. The standard deviation for power prices has increased from 0,46 to 0,73 Eurocent/kWh. For the zero exchange case, prices are reduced for prices that were relatively low initially. All prices below 3,5 Eurocent/kWh are lowest for Case A2_G. On the other hand, prices are higher for cases where prices were relatively high initially. In particular, the marginal cost for new gas-power (4,4 Eurocent/kWh) is no longer an upper limit for power prices in the zero exchange case. There are many examples of prices up to 6 Eurocent/kWh and above.

Figure 7.4 shows the first 100 simulated prices for the same German area in 2004. The typical within-week price profile is not altered a lot in the A2_G case compared to case A1. However, fluctuations have increased in general, and in particular there are price-peaks.

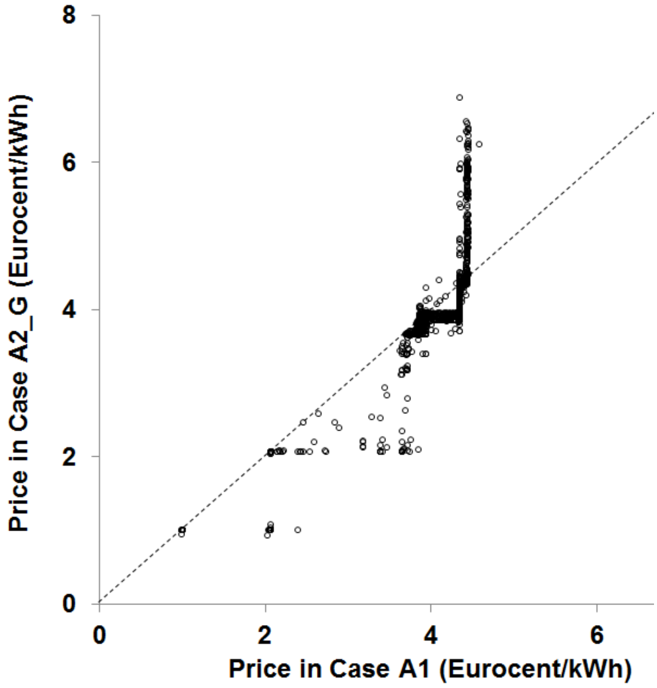

Figure 7.3 All simulated prices in TYSK-SYD (area 33) for climate year 2004 for Case A1 and Case A2_G respectively.

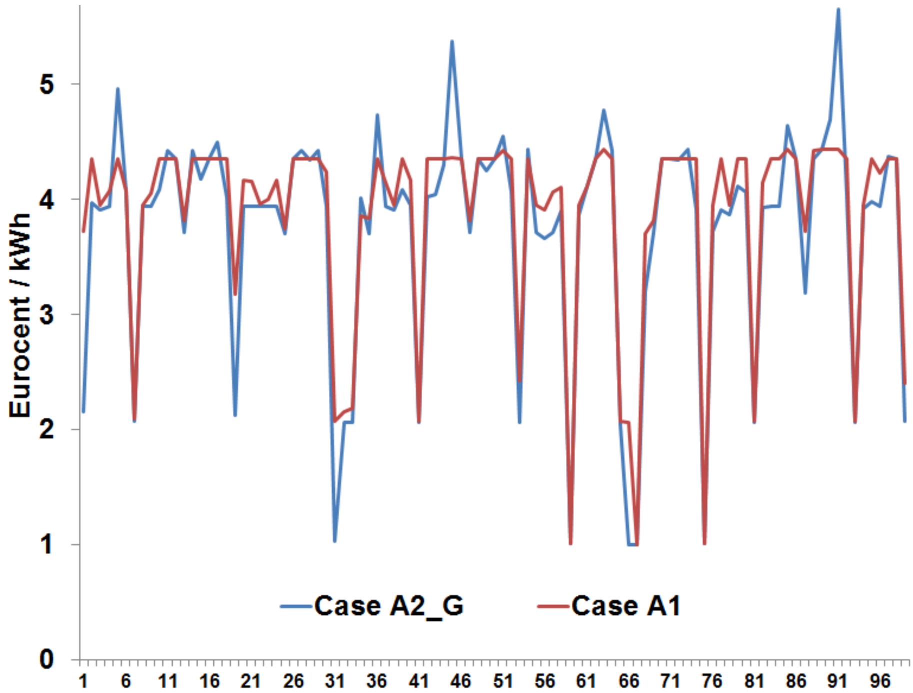

Figure 7.4 First 100 simulated prices for TYSK-SYD (area 33) for climate year 2004 in case Case A1 and Case A2_G.

For Germany as a whole, the average price during the evening peak, which has highest prices, increases by 0,5 Eurocent/kWh in Case A2_G compared to Case A1. On the other hand, average prices are reduced between 0,1 and 0,3 Eurocent/kWh for all other periods.

Average prices are reduced in all model countries. It is still possible to import from France, while trade is no longer possible with the other countries on the outside of the simulated system. All these countries (Czech, Estonia, Lithuania, Switzerland, Poland and Austria) were net importers in the Basecase, cf. Figure 4.2. There are largest reductions in average prices within the Nordic area (approximately 0,3 Eurocent/kWh).

<u>Zero exchange and nuclear phase-out in Germany (Case_A2_GA)</u>
In the final case there is no trade on the system boundary (except towards France as explained above), and in addition we assume a total phase-out for German nuclear power. Figure 7.5 shows all simulated prices for 8 areas for climate year 2004 for the following cases: A2, A2_G (no trade on system boundary) and A2_GA (no trade on system boundary, and no nuclear power production in Germany).

In general, the lack of trade on the system boundary gives more price-fluctuation, while no nuclear power in Germany gives higher prices. In Figure 7.5 this is especially clear for areas at the European continent and for areas that is well connected to the continent, i.e. TYSK-NORD, TYSK-VEST, DANM-VEST, SVER-SYD and NETHERLANDS. For the two German areas there is curtailment in 4 of 1768 simulated cases (0,2 %) for climate year 2004 in Case A2_GA. In these cases power prices are 37,5 Eurocent/kWh (above maximum value for vertical axis in Figure 7.5).

For areas the areas that are less connected to the European continent (except France), i.e. GB-MID, NOR-VESTSYD and SVER_ON2, power prices are less affected by lack of trade on system boundary and by German phase-out of nuclear power. Congestion prevents the occasionally high prices in Germany to determine the price within these areas. In NOR-VESTSYD and SVER-ON2, lack of trade on system boundary gives lower power prices, while the phase-out of German nuclear power gives higher power prices. There are however not any major effects on price-fluctuations. In GB-MID, there are only minor effects on power prices. The reason is probably that GB imports from France, and that prices often are relatively high in GB compared with connected areas, cf. Figure 4.15. Therefore, the price is mostly determined by conditions within GB.

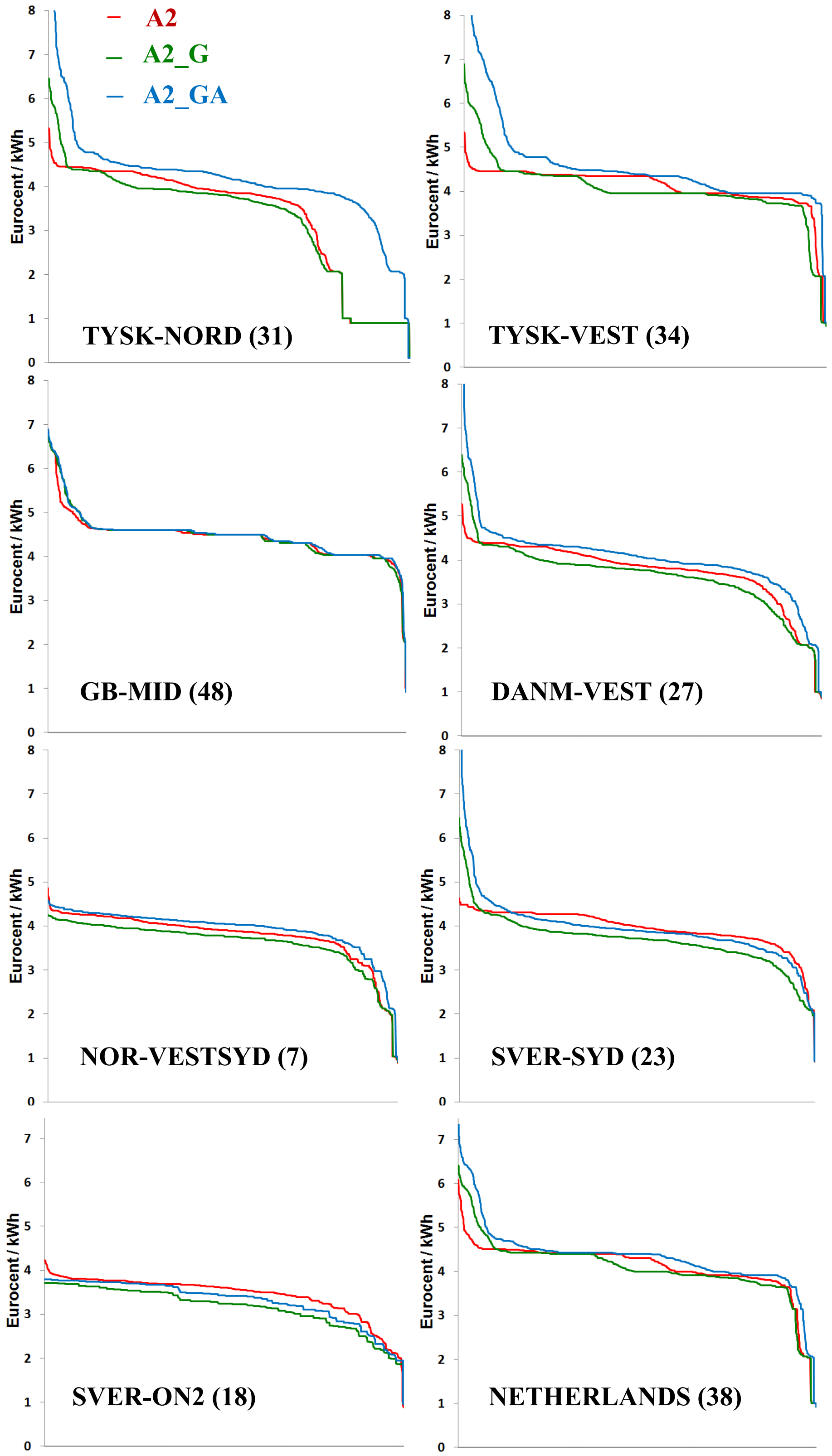

Figure 7.5 All simulated prices for 2004 in 8 areas for scenario A2, A2_G and A2_GA

SINTEF

8 Conclusions

8.1 Summary

Goal for study

The main goal for the study has been to evaluate the profitability of an integrated North Sea grid compared to direct connections. We have simulated the power markets in the Nordic area, GB, Germany, Netherlands and Belgium for year 2020 using the EMPS model. In total, 10 North-Sea grid alternatives have been evaluated. For a direct connection between Norway and GB we consider different connection points in both countries. Thereafter, we study cases where the cable between Norway and GB is connected to wind-farms and electrification of petroleum installations in the North Sea, and cases that include an extra connection to Germany.

Assumptions for 2020-system

We have combined detailed information about the existing power system with recent forecasts for power system development towards 2020 to prepare our dataset to the EMPS model. It has been a premise for the study that the ambitious national implementation plans for renewable power generation in the EU is carried out within 2020. Differences in the variability of wind- and solar-power generation for different areas are accounted for. Capacities for thermal power generation and transmission are based mostly on ENTSO-E forecasts, while prices for fossil fuels and CO_2 are based on a recent Primes-model simulation for 2020 that take into account EU-targets for renewable power generation.

Reported results

Simulation results for Basecase is reported in detail, including annual balances for each country, production from different technologies, transmission and prices in all price-areas. Simulation results for Basecase are also compared with official statistics. For other cases we focus on those results that are of particular interest for each case.

Cost-benefit

Total economic surplus in the whole simulated system is calculated for each case. In particular, the average annual operating profits (surplus for producers, consumers and TSOs) are calculated. For each case we also calculate investment costs for cables and auxiliary equipment, and calculate the annualized value (i.e. a constant annual value in the expected life of the investment that give the same present value as overnight investment costs). Investment costs of power cables and auxiliary equipment are scaled proportionally from the 600 MW block studied in the Windspeed-project to the 1400 MW alternatives in our study. Annual values for operating profits and investment costs are normalized to zero for one of the alternatives (only direct connections). For each of the other alternatives, a cost-benefit analysis is carried out by adding together normalized values for annual operating profits and annualized investment costs. For two cases where the additional cable from Norway to GB is connected to a North Sea node on the Norwegian side, the cost-benefit analysis was carried out for three alternative technology options and for two amounts of wind-power installed in the North Sea.

Major findings

On average, electricity prices are higher in GB than in any other country in the simulated system. A cable between Norway and GB is therefore mostly used for export to GB. In general, the gains from a transmission line are high if there is a large price-difference between the two connected areas. For a direct connection it is therefore not surprising that the best connection point on the Norwegian side (only considering operating profits) is the northern alternative were power prices are slightly less than for the other alternatives further south. On the British side, power prices are in general less in the northern area than in the mid-area. Still, it is more profitable to connect the cable to the northern area. The reason is that there are occasionally very low power prices in the northern area because of a lot of renewable power generation. Therefore, the average price-difference between connected areas will be largest if the connection point on British side is in the northern area. Thus, this alternative gives higher total economic surplus than a connection point further south.

If the cable between Norway and GB also is connected to a North Sea node where connected wind-power production sometimes is less than electricity consumption at petroleum installations, the export potential on the cable is reduced. If net consumption in the North-Sea node is 100 MW, then only 1300 MW arrives at British side even if the export from Norwegian mainland is 1400 MW. This will typically be costly for the system since simulated system since power prices in most cases are higher in GB than in Norway.

Even for the most flexible technology (and most expensive) option it is profitable to connect a cable between Norway and GB to Doggerbank, compared with a corresponding direct connection. For this case, the saved investment costs (cable meters and equipment on British mainland) are higher than the lost benefits during operation. If the cable is connected to a Norwegian North Sea node, total investment costs goes up because of the additional offshore equipment, while the benefit of the cable goes down because of reduced flexibility. Unless additional wind-power is installed, the direct connections are therefore more profitable than integrated solutions. However, if 1000 MW wind-power is installed and the T-junction technology is applied, then the integrated solutions are more profitable than direct connections.

A connection to northern parts of Germany give increased operating surplus. In some cases transmission from Germany to GB substitutes export from Norway. In cases where wind-power generation at Doggerbank blocks for export to GB, a connection to Germany can be utilized for transmission between Germany and Norway.

<u>Additional cases</u>
We have carried out additional cases to study some important uncertainties in our study. Cases of additional wind-power installed in the North Sea give reduced cost of North-Sea node. Wind-power production exceeds electricity consumption at North Sea node at more occasions, and allows full export towards the British side. If all German nuclear power is phased out, there is moderate increase in average power prices, especially in Germany and in the Nordic area where power prices were relatively low initially. An increased price in Germany gives reduced benefit of adding an extra leg to Germany for a cable between Norway and GB. The reason is probably that average prices are similar in GB and Germany after a nuclear phase-out in Germany. If no exchange to countries on the outside of the simulated system (except France) is possible, then average prices go down. Prices will however fluctuate more, and the peak-price frequency increases a lot at the European continent. If all German nuclear power is phased out, and no exchange to countries on the outside of the simulated system (except France) is possible, there are some occasions of curtailment in Germany. There is also a considerable increase in peak-prices for areas that is well connected to the German areas.

In general, altered assumptions regarding exchange on the system boundary and German nuclear power have limited effect on the relative high power prices in GB. The profitability of cables between Norway and GB is not improved by a phase-out of nuclear power in Germany or by more pessimistic assumptions regarding trade on the system boundary.

8.2 Uncertainties and limitations

General
Uncertainties can be discussed with different perspectives. On approach is to discuss the uncertain factors as such, for instance the general growth rate for the economy to 2020. Another approach is to discuss uncertainties to model simulations because of uncertainties in specific input parameters, for instance electricity demand and willingness to pay for electricity. Our discussion is an overlapping mixture of these different approaches or fuel prices.

RES-E targets
Electricity markets are heavily dependent on political decisions and changing priorities. The willingness to support renewable electricity generation in the EU is caused i.a. by the need for combating CO_2-emissions, and concerns for the stability of gas-deliveries from Russia. Presently, the EU holds ambitious targets for renewable power production and this has been implemented in our study. It is however not obvious that these ambitious targets will be met. Even if targets are implemented in laws, priorities can always be changed if there is a political will to do so.

Economic development in Europe
The on-going financial crisis in Europa and the corresponding stress on European co-operation and currency can be obstacles for implementation of policies to increase renewable power generation and to reduce CO_2-emissions, and it may affect economic growth. An uneven economic growth in the EU may also give differences in the growth rate for electricity demand, and it this way affect prices and the need for transmission of electricity between regions.

Greenhouse-gas agreement
The lack of a global environmental agreement to reduce greenhouse-gas emissions can give reduced support for such measures in Europe too. If e.g. the present emission permit market is ended, this will have considerable effects on operating costs especially for coal-power and, as a second-order effect, on fuel-prices.

Nuclear power
The future for nuclear power in Europe is uncertain. On one hand it is emission free and it has small operating costs. On the other hand, it is disliked for risks and there are challenges for the long-term storage of radioactive waste. Presently, the risks are in focus, but this may change over time. We have studied effects of a phase-out of German nuclear power. In general, this gives higher prices. This effect will be even stronger if more countries phase-out this technology.

Technology
Technological development for power generation, CO_2-abatement and transmission may have considerable influence on power prices. Different technological developments will have different consequences for the profitability of specific transmission lines. If for instance, the large amounts of potential energy in the Norwegian Sea can be utilized at competitive costs, it may be profitable to invest in many new off-shore transmission lines from Norway. On the other hand, a breakthrough for CO_2-abatement in coal-power generation may lead to a reduced need for exporting renewable power from the Nordic area.

Failures
Failures and reduced availability for existing equipment may have considerable impacts on prices. For instance, reduced capacity in Swedish nuclear power plants and a failure on a cable between Norway and Denmark have given large price-effects in the Norwegian system in recent years. In model simulations, we

have not accounted for unexpected events. This is too optimistic since there will be failures from time to time. If such failures in practice lead to higher price-differences between areas, the value of (remaining) transmission capacity will be higher than indicated in our study.

Competition
We have carried out a study for a uniform competitive spot market in northern Europe. In reality, it is an on-going process to make European power markets more integrated and transparent. It is therefore possible that market imperfections and possible use of market-power may affect the profitability for a specific cable alternative. The profit can be higher or lower depending on the type and location of the imperfection.

Balancing markets
There is always a deviation between spot-market quantities and actual quantities for generation and consumption during operation. The day-ahead forecasting error will increase considerably when more renewable power generation is connected to the European grid towards 2020. In a market-based system, prices will typically be more volatile in a balancing market than in a spot-market since controllable units must respond quicker to a price-signal (e.g. on 15 minutes notice instead of day-ahead). It may therefore be profitable to reserve some of the capacity of a cable to the balancing market. This option can possibly increase the profitability for new cables. We have not included extra incomes from the balancing market or intra-day markets our study.

Price-variation
Compared to some historical price-variations, the within-day price variations in our study are relatively small. There may be several reasons for this. For instance, our inputs for start-up costs can be incorrect, or observed price-variations in the past have been caused by market-imperfections not included in the EMPS model. It is possible that simulated price-variations for 2020 are too small for the assumed system. If prices fluctuate more, this will typically increase the value of transmission lines.

Uncertainty types
Uncertainty caused by variations in climate variables such as inflow to reservoirs and wind-speeds is accounted for in an EMPS simulation. However, all other kinds of uncertainty must be handled by making specific scenarios. We have considered some uncertainties in specific scenarios, while many others are not dealt with. For instance, we have not analysed the effects of making new assumptions for:

- Fuel prices
- CO_2-permit prices
- Electricity demand
- Installed capacities for production and transmission (except in the North Sea)

8.3 Final remarks

Main finding
If a cable between Norway and GB is connected to a North Sea node at Norwegian side, the total cable meter cost is reduced. But there are two costs elements that can be considerably larger. Firstly, some of the export from Norway to the GB will be blocked when there is net consumption in the node. Secondly, other investment costs elements than cable meters are higher when the cable is connected to a North Sea node. Additional equipment includes AC/DC converter stations, DC breakers and switching gears off-shore. The total investment costs are therefore higher even if total cable length is reduced. The saved cable meters also have considerable less capacity. However, if additional wind-power is installed in the North Sea node, and

the connection is optimized (not flexible regarding future needs), then a cable connected to the offshore node is more profitable than a corresponding direct connection.

The need for an all-European perspective

Our study has shown that the economic consequences for a single country can be totally different than for the whole simulated system. For instance, it can be profitable for a single country to develop or operate the grid such that congestion comes within domestic borders where the national TSO obtain all the income from price-differences. An all-European perspective is therefore needed to ensure a rational development of the European grid.

Recognizing findings while appreciating uncertainties

No mathematical model and corresponding input-data of real-life phenomenon will be absolutely true. The mathematical model formalizes some mechanisms, while many others are omitted. Inputs are more or less stylized quantifications of those mechanisms that are represented in the model. Often, it is not even obvious how a model-result could be tested, since the formats of the outputs from the model do not fully coincide with observable quantities. This is especially true for the study of humans or human institutions, such as a study of power markets. Forecast or predictions are even harder to evaluate since the study will be based on a set of assumptions that may or may not be true for the forecasted year. But even if some of the explicit or implicit assumptions of a study necessary will be false or unrealistic, it does not imply that the study is worthless. Instead, important findings should be recognized as a consequence of the assumptions in the study, and they shed light on a part of the full problem under consideration. At the same time, one should be critical to the applied methodology, question to which degree model and inputs describe real-life mechanisms, and appreciate the inevitable uncertainties in a study of the future. For instance, it is important to consider or study effects of changing important assumptions.

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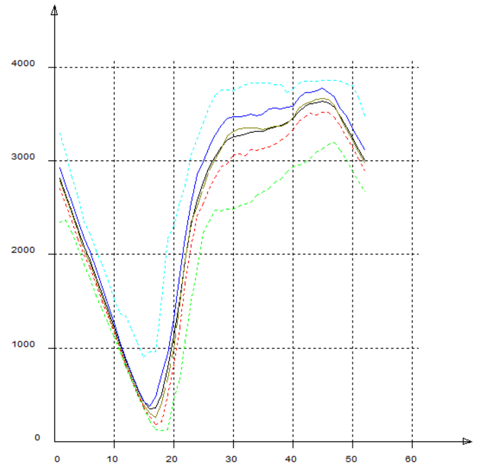
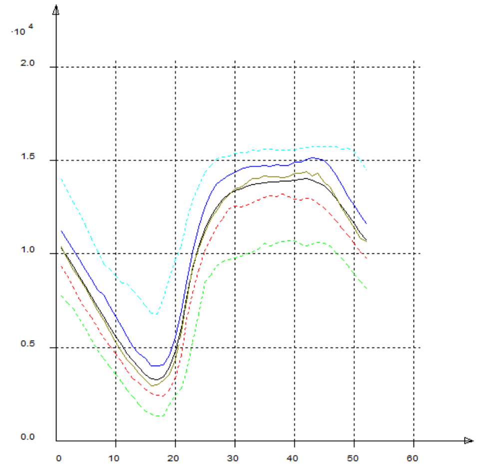
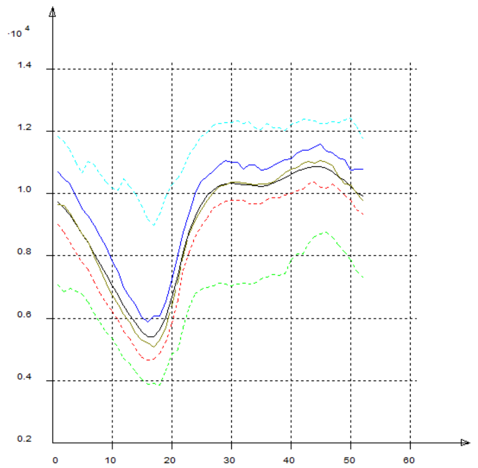
Appendix A. Percentiles for reservoir-levels for Nordic areas.



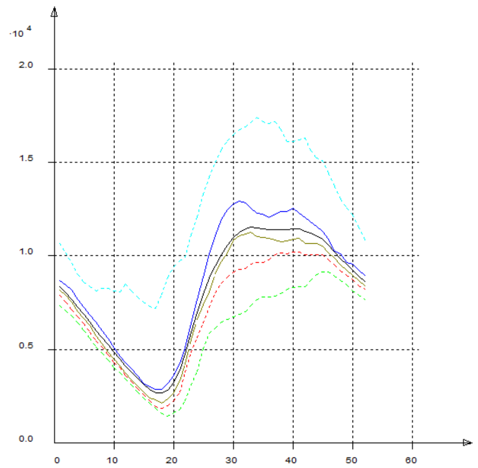
NOR-GLOMMA



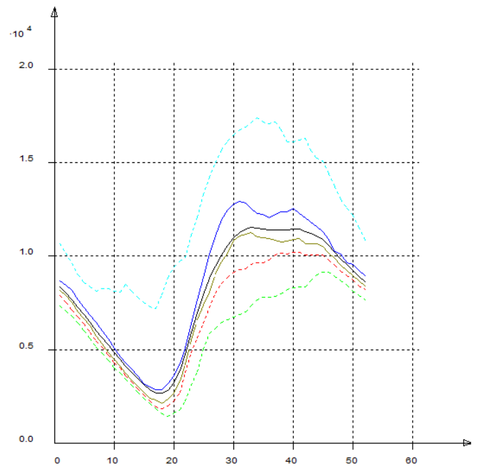
NOR-OSTLAND



NOR-SORLAND



NOR-VESTSYD



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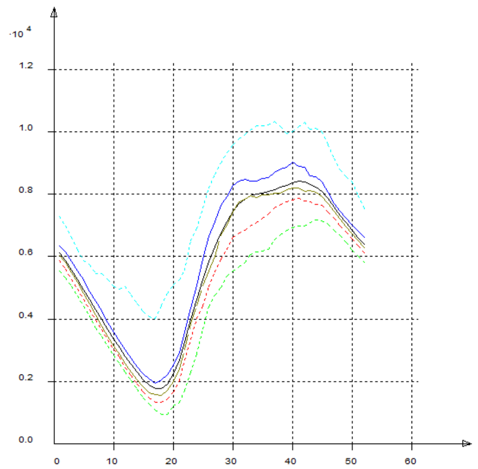

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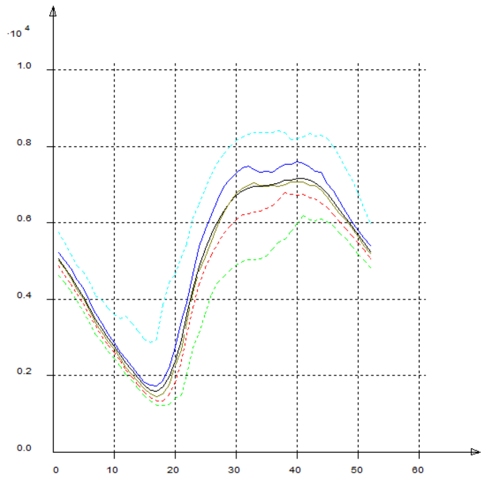

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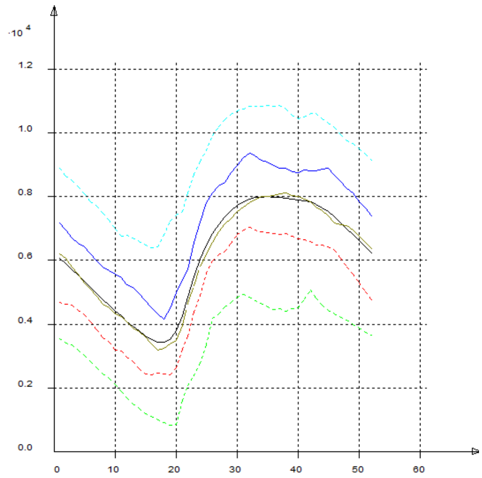
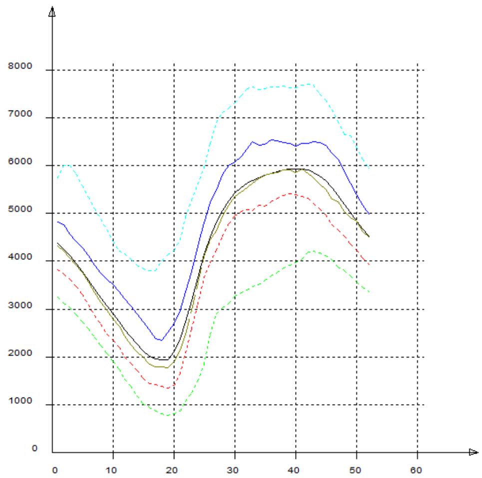


NOR-HELGE



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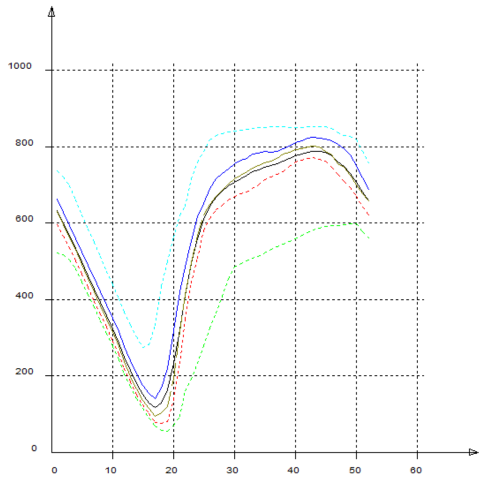
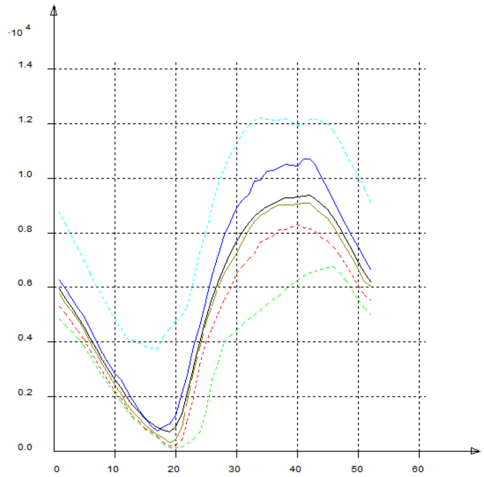
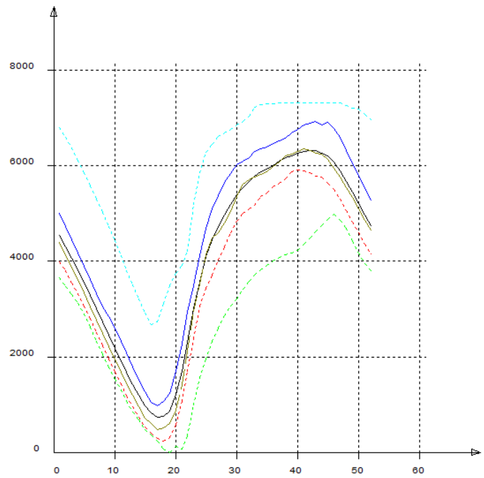


NOR-FINNMARK



SVER-ON1



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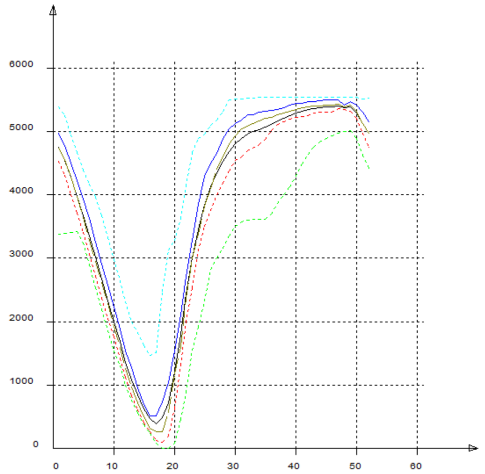

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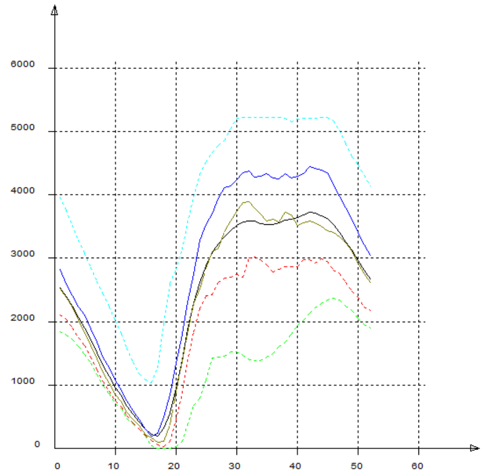

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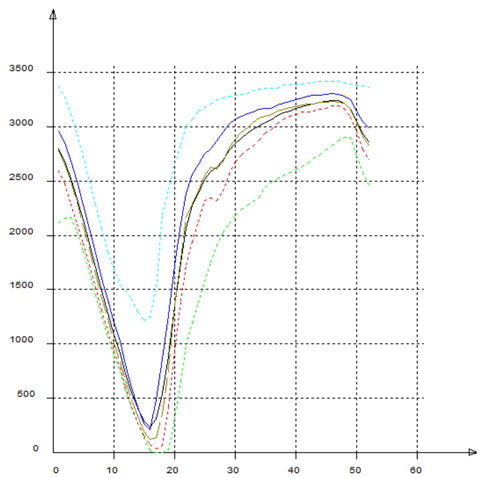

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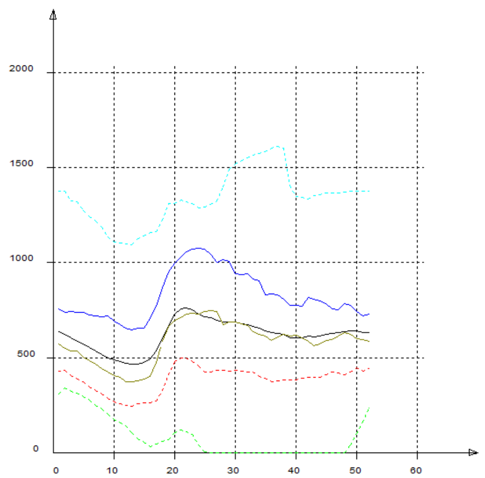

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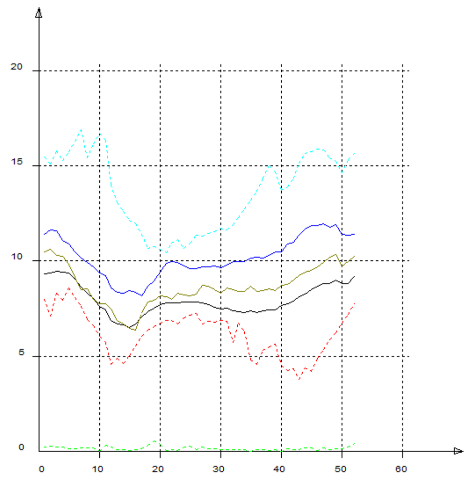

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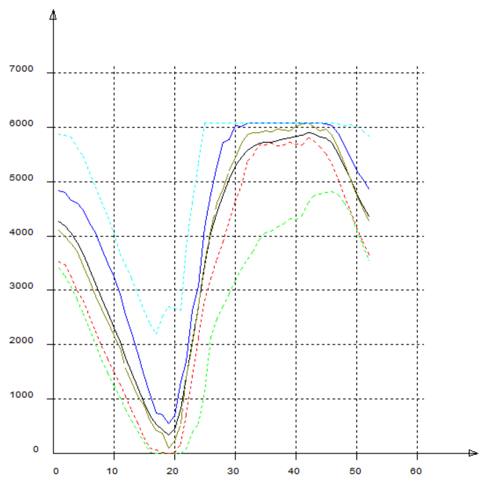
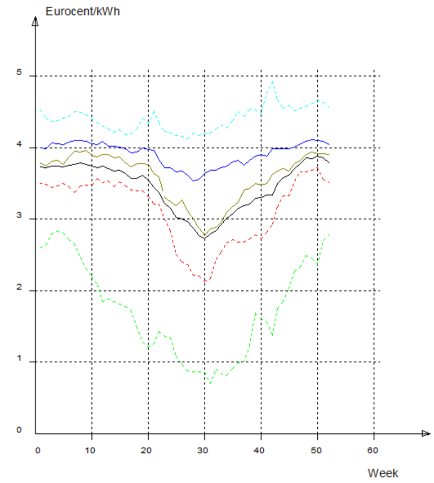
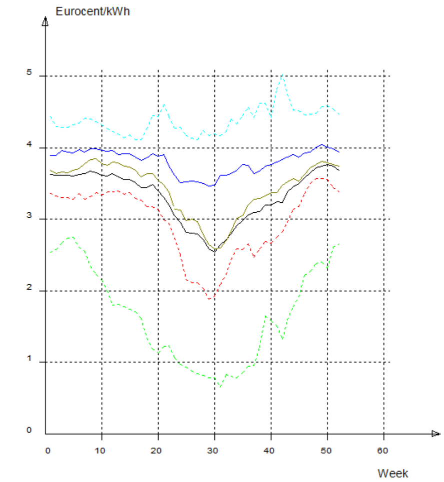


FINLAND

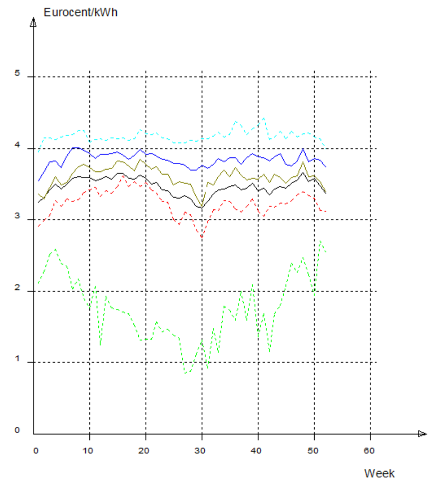
Appendix B. Percentiles for prices in 6 areas.



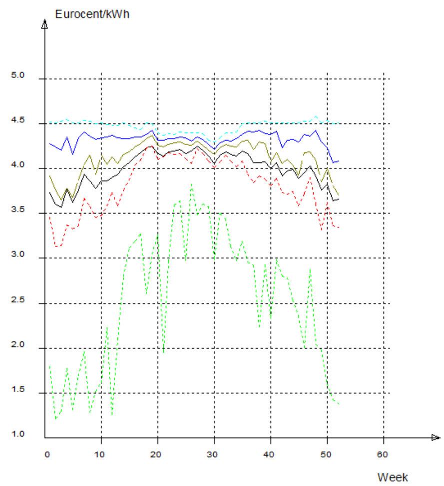
NOR-VESTSYD



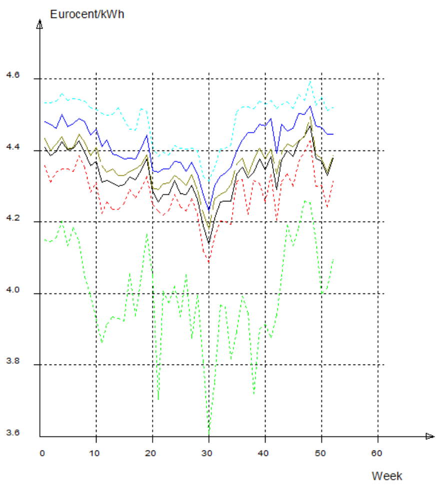
NOR-VESTMIDT



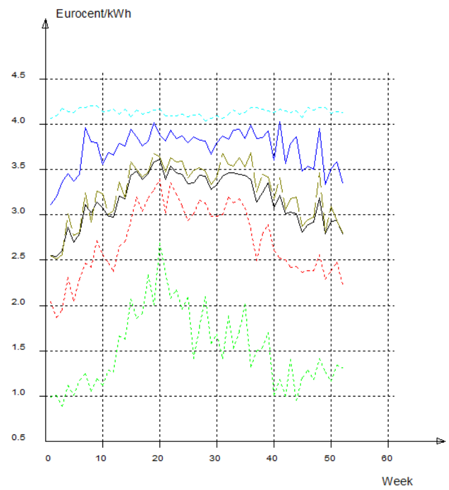
NOR-SORLAND



GB-NORTH



GB-MID



TYSK_NORD

Appendix C. Geographical locations.

Table C.1. gives a mapping of nodes and an exact geographical location for the assumed connection point, while Figure C.1. shows each point on a map. This is used to measure distance for cables [23].

Table C.1. Location for connecting nodes

Node	Location	Coord N	Coord E	
GB-Mid	Easington	54.767	-1.3	Source: National Grid
GB-North	Peterhead	57.513	-1.781	Source: NorthConnect
Ge-North	Brunsbüttel	53.897	9.151	Source: Statnett
NS-DB		55	3.05	Source: Vestavind
NS-North		62.34	4.23	Source: TR, 12X684.10
NSO-N	Snorre	61.44	2.21	Source: TR, 12X684.10
NSO-S	Ekofisk	56.64	3.33	Source: TR, 12X684.10
NS-South		56.71	4.23	Source: TR, 12X684.10
Sorland	Feda	58.283	6.865	Source: NorNed
Vestmidt	Grov	61.613	5.32	Source: TR, 12X684.10
Vestsyd	Kvilldal	59.514	6.636	Source: Statnett

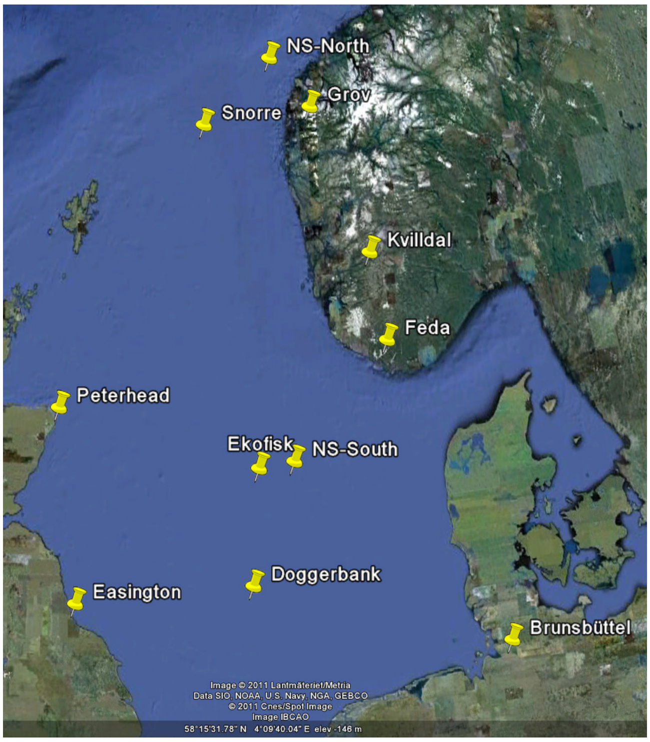


Figure C.1. All locations

Note: In final cost-calculation Northern North Sea Node is assumed to be located such that cable between Norway and GB goes through this area.

Appendix D. Technology specification.

Table D-1 gives additional details for each of the included line-segments. Only differences compared to Case A1 are identified. The term “AC Breaker” and “DC Breaker” also includes switching gear. Offshore converter station also includes platform. For some lines, two numbers are provided for offshore DC breakers. The first number refers to the alternative “Fewer DC-breakers”, while the second number refers to the alternative “Flexible setup”. The lines that are included in the different grid-alternatives are also identified. For some alternatives there is a "-1" because direct connections from offshore nodes to shore are avoided for cases where cable between Norway and GB is connected to offshore node. However, for these cases additional windfarm converters are needed. This is also identified in the table.

Table D-1 Technical specifications for each line-segment, included lines in different grid-cases, also identifying T-junctions and windfarm converters.

				Onshore		Offshore			Cases														
Alt	Connection	Length	MW	Converter	AC Breaker	Converte	DC Breake	AC Breaker	A2	B1	B2	B3	C1	C1-T	C1-W	C1-TW	C2	C2-T	C2-W	C2-TW	C3	D1	D2
1	NOR-VESTSYD - GB-MID	713	1400	2	2				1														
2	NOR-VESTMID - GB-MID	855	1400	2	2					1													
3	GB-NORTH - NOR-VESTMID	607	1400	2	2						1			1		1							
4	NOR-SORVEST - GB-MID	636	1400	2	2							1						1		1			
5	NS_North - NOR-VESTMIDT	99	250	1	1	1		1					-1	-1									
5	NS_North - NOR-VESTMIDT	99	1000	1	1	1		1							-1	-1							
5	NS_North - NOR-VESTMIDT	99	1400	1	1		0 / 1						1		1								
6	NS_North - GB-NORTH	508	1400	1	1		1						1		1								
7	NOR-SORVEST - NS_SOUTH	236	250	1	1	1		1									-1	-1				-1	-1
7	NOR-SORVEST - NS_SOUTH	236	1000	1	1	1		1											-1	-1			
7	NOR-SORVEST - NS_SOUTH	236	1400	1	1		0 / 1										1		1			1	1
8	NS_SOUTH - GB-MID	409	1400	1	1		1										1		1			1	
9	NOR-VESTSYD - DOGGERB/	547	1400	1	1		1														1		
11	NS_SOUTH - TYSK-NORD	442	1400	1	1		1															1	1
12	NS_SOUTH - DOGGERBANK	204	1400																				1
	T - JUNCTION	0	250											1									
	T - JUNCTION	0	1000													1							
	T - JUNCTION	30	250															1					
	T - JUNCTION	30	1000																	1			
	WINDFARM CONVERTER		250										1	1									
	WINDFARM CONVERTER		1000												1	1							
	WINDFARM CONVERTER		250														1	1				1	1
	WINDFARM CONVERTER		1000																1	1			

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