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Value of large-scale balancing and storing from Norwegian hydropower for the German power system and generation portfolios

Scientific study

for E.ON Kraftwerke GmbH

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Table of Contents

I Executive Summary

Norwegian hydropower can cover the demand for flexibility and storage driven by renewables in the European power system

The European power system is undergoing a substantial transition. Renewable Energy Sources (RES) gradually substitute conventional power generation. Since most of the RES are wind and solar power plants with intermittent feed-in, the volatility of the electric residual load increases. This triggers a demand for flexibility and storage in the European power system. Norway already generates most of its electricity from highly flexible hydropower plants and there is still potential to further increase turbine and pump capacities. With the corresponding grid enhancement, Norway could provide a significant share of the necessary flexibility and storage capacity for the European power system.

What is the benefit of having access to Norwegian hydropower?

In order to investigate the potential of Norwegian hydropower for Europe, the Norwegian Centre for Environmental Design of Renewable Energy (CEDREN) set up the HydroBalance project. E.ON Kraftwerke GmbH (E.ON) acts as an Industrial Partner to CEDREN and supports the research in the work package comprising the identification and evaluation of business models. Aim of this study is – amongst others – to estimate the value for German utilities or grid operators if they had access to hydropower plants in Norway.

Benefit estimation by macroeconomic and microeconomic simulations for scenarios of the year 2050

In this study, the benefit of having access to Norwegian hydropower is estimated on two levels. On the macroeconomic level, the general additional value of the hydropower expansion in Norway is derived from simulations of the European power system dispatch. The underlying scenarios represent an RES dominated power system for the year 2050. The main difference between the scenarios is the degree of flexibility provision by Norway. In the scenario B "Big

Storage", the (turbine) capacity of Norwegian hydropower is increased by 30 GW and Norway's power system and markets are strongly linked to the rest of Europe. In the scenario C "Niche storage", the (turbine) capacity expansion is 20 GW and a larger share of the flexibility demand is provided by the power systems within the other European countries. Further macroeconomic investigations focus on the potential cost reduction for transmission system operators (TSO) from cross-border reserve provision. With spot and reserve prices derived from the macroeconomic simulations, additional microeconomic portfolio simulations are performed for a RES and a mixed portfolio with and without access to a Norwegian hydropower plant. The additional flexibility of the hydropower plant supports dispatch optimization and can compensate RES prognosis errors.

Additional value from Norwegian hydropower for Europe from a system point of view

The potential utilization of the increased Norwegian hydropower capacity requires a strong expansion of transmission capacities. The necessary cable capacity in the North Sea amounts to nearly 30 GW in scenario B and 20 GW in scenario C. With this additional capacity, Norwegian hydropower creates an additional value for the European power system by integrating surplus RES generation and smoothening conventional power plant dispatch. The specific reduction of annual variable system cost is 130 EUR/kWa in scenario B and 148 EUR/kWa in scenario C. Assuming current investment costs for hydropower capacity in Norway and the corresponding sea cables, the cost reduction is higher than the annual costs for the investment. Thus, a benefit from a system point of view can be achieved.

Benefit from cross-border reserve exchange dependent on other flexibilities

Cross-border reserve exchange from TSO-TSO agreements reduces cost for reserve provision since the available transmission capacities are optimized for scheduled energy and additionally for reserve provision. This way especially Norway can provide short-term flexibility for Europe from hydropower plants. The achievable reduction of total variable system costs from a European-wide reserve exchange is 345 mil €/a in scenario B and 70 mil €/a in scenario C. The higher benefit in scenario B results from the reduced inherent flexibility within the European countries.

Significant additional value from flexible hydropower in RES generation portfolios

In the microeconomic investigations, the combined marketing of the RES portfolio with a Norwegian PSP results in an additional benefit (portfolio effect) of up to 0.9% of the achievable annual contribution margin on the markets for scheduled energy and reserve. The mixed portfolio has a higher flexibility itself due to dispatchable conventional generation capacity and therefore only reaches a portfolio effect up to 0.4%. When additionally taking into account prognosis errors in the RES portfolio the additional benefit from the Norwegian hydropower plant in the portfolio reaches up to 2.4% in relation to a separate marketing. This benefit mainly comes from the possibility to utilize surplus generation from prognosis deviations in the balancing group by dispatching of the pump.

1 Motivation and Study's Objective

The transformation of the European energy system towards an energy mix with increasing share of Renewable Energy Sources (RES) affects the feed-in structure of power generation. Especially the intermittent feed-in of wind and solar power is not dispatchable and can only be controlled in limited ranges, thus triggering the need for energy storages. One possible option for storage is to make use of the large potential of Norwegian hydropower in the Norwegian energy system. A realization of this option would require significant investments in both, hydropower plants and transmission capacities. For hydropower generation, besides construction of new plants, upgrade of existing plants by adding pumps is possible as well. In order to transmit power to and from the plants, new transmission lines for connecting Norway to the rest of Europe - but also within the country itself - are necessary.

The Norwegian Centre for Environmental Design of Renewable Energy (CEDREN) has set up a research project ("HydroBalance") in order to estimate the potential of Norwegian hydropower for balancing in Europe. E.ON Kraftwerke GmbH (E.ON) acts as an Industrial Partner to CEDREN and supports the research in the work package comprising the identification and evaluation of business models. Aim of this work package is – amongst others – to estimate the value for German utilities or grid operators if they had access to hydropower plants in Norway. The value for utilities comes from the access to flexible generation, which can be marketed stand-alone or in a generation portfolio on the spot market and balancing markets. For grid operators a possible benefit from flexible Norwegian hydropower derives from TSO-TSO agreements on cross-border balancing. These agreements could optimize reserve provision und thus reduce total balancing costs. Against this background, the aim of this study is to quantify the advantages for utilities and grid operators from having access to Norwegian hydropower in the future European power system. Furthermore, the spot and reserve market prices derived in this study will be used in the following work packages of the HydroBalance project.

2 Methodology and Structure of the Report

The effect of integrating Norwegian hydropower into the German power market is quantified by simulations of two different scenarios for the year 2050. The investigation is split into three main parts. The first part investigates the benefit for the European generation system resulting from the expansion of Norwegian hydropower. Therefore, an additional European market simulation is performed with today's values for Norwegian hydropower capacity in comparison to the two expansion scenarios. While the second part of the study comprises the macroeconomic effects for Europe and Germany from different schemes of including the hydropower in the European market, the third part focusses on the microeconomic effect for generation portfolios in the German power market. In order to derive macroeconomic quantities such as power generation, power exchanges and power prices, a European market simulation is performed for different weather years in the second step. The European market simulation has an hourly time pattern and considers load coverage as well as (simplified) reserve constraints. As shown in Figure 2.1, the resulting cross-border exchanges are used in a more detailed simulation of the German system with a ¼-hourly time pattern for the weather year 2008 and under consideration of different reserve qualities. Both scenarios for the year 2050 include an increase of Norwegian hydropower capacity (see Chapter 4).

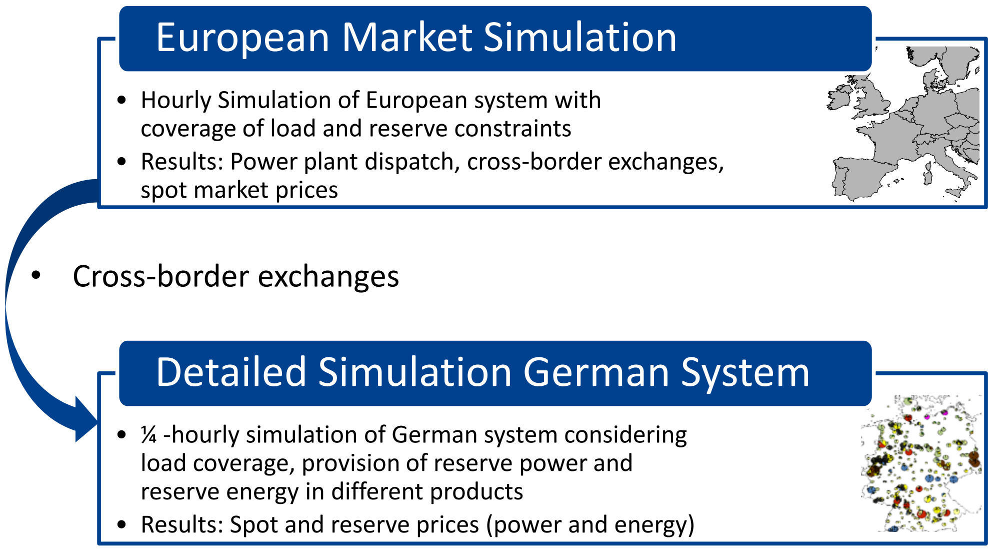

Figure 2.1: European and German market simulation

A participation of a Norwegian hydropower plant in the German market requires the reservation of capacity on the interconnector between Norway and Germany. This has to be considered for the evaluation of the benefit for a German utility. The quantification of the benefit for grid operators from optimized cross-border balancing also requires consideration in the European market simulation. Therefore, three different cases regarding the utilization of cross-border capacity (Net Transport Capacity – NTC) are considered (see Figure 2.2).

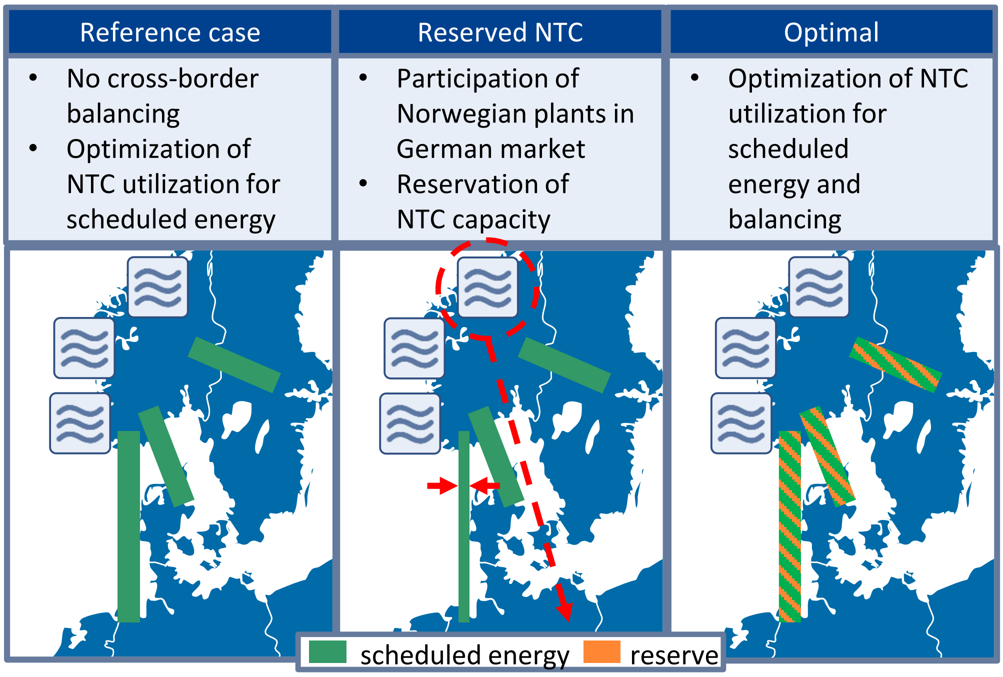

Figure 2.2: Cases for the utilization of cross-border capacity

In the reference case, the cross-border capacity is only utilized at the spot markets to optimize the exchange of scheduled energy. In contradiction, the optimal case additionally considers optimization of cross-border balancing. The case "Reserved NTC" represents the reservation of cross-border capacity for participation of a Norwegian hydropower plant in the German power market.

The microeconomic part of the study contains portfolio optimizations for two different generation portfolios in the German spot and reserve markets with prices derived from the German market simulation. In order to represent reserve products, the ¼-hourly reserve prices are summarized to 4-hour reserve products. This implies a reduction of today's values for the commissioning time of reserve products, which are up to one week. These portfolios are optimized with and without the Norwegian hydropower plant. While the participation on the spot market is unrestricted, the provision of reserve power is limited to the share of the portfolio in the German-wide simulation. This approach avoids the overestimation from reserve market revenues in the portfolio optimization. Main results of the microeconomic simulation are the ¼-hourly portfolio dispatch and obtainable revenues on the different markets. Figure 2.3 visualizes the relation between macroeconomic and microeconomic simulations.

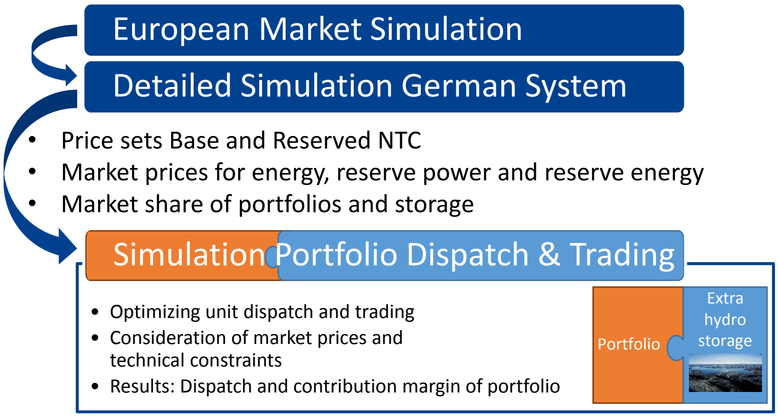

Figure 2.3: Relation between macroeconomic and microeconomic simulations

The simulation of different cases in the macroeconomic as well as in the microeconomic investigations allows the derivation of several key figures for the additional value of Norwegian hydropower in a German portfolio as shown in Figure 2.4. For determining the portfolio effect, first an optimization of the portfolio and the hydropower plant is performed separately. The additional contribution margin of a combined optimization in comparison to the sum of contribution margins in the separate optimization yields the additional value of the joint portfolio. Both of these simulations require a reserved NTC between Norway and Germany. Another key figure comes from the comparison between cases “Base” and “Reserved NTC”. This way the additional value of having the Norwegian hydropower plant in the portfolio against not having the hydropower plant in the German market is derived. Furthermore, the investigations include exemplary rolling dispatch simulations for the portfolios under consideration of updating feed-in prognosis for RES generation. The simulation is carried out for the time span between March 2013 and February 2014 using historic prices and feed-in data. This way the additional value of flexibility from hydropower plants regarding the prognosis error of intermittent RES can be quantified.

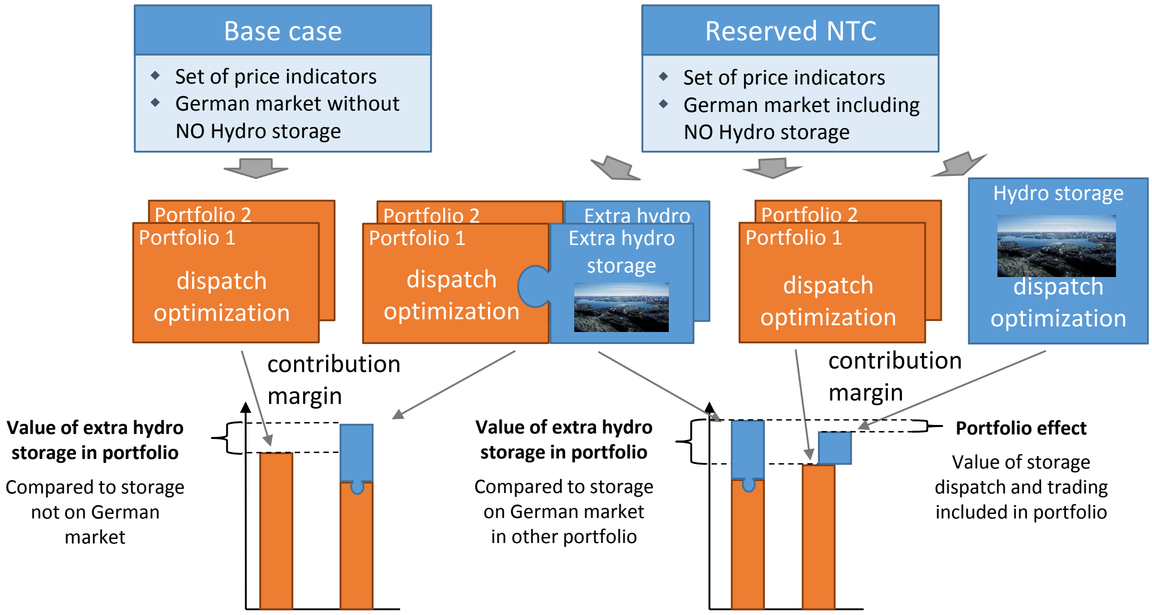

Figure 2.4: Evaluation of the additional microeconomic value from Norwegian hydropower

In the following, Chapter 3 describes the applied models and methods in this study. After that, Chapter 4 presents the input data, especially for the different scenarios and the different portfolios. Chapter 5 contains the macroeconomic and microeconomic results derived from the simulations while Chapter 6 draws conclusions and summarizes the study.

3 Optimization Models

The following subchapters describes IAEW's optimization models used to carry out the simulations in this study. Here, Chapter 3.1 explains the method for reserve dimensioning while Chapter 3.2 outlines the approach of the European market simulation. Chapter 3.3 describes the detailed German market simulations and finally Chapter 3.4 explains the applied method for portfolio optimization.

3.1 Reserve Dimensioning

In order to simulate reserve markets it is necessary to determine the demand for reserve capacity. Since this demand is highly sensitive to the forecast error of RES generation, the forecast error has to be taken into account for reserve determination. In the last years, a method to simulate imbalances and determine reserve demand has been developed at IAEW [1]. This method is based on a Monte Carlo simulation where all relevant factors are being simulated:

- **Forecast error RES**: Based on the probability functions for the forecast error, the resulting market area wide forecast error is simulated for wind and solar power. The probability depends on the height of the forecast and the forecast error simulated for the previous time step.

- **Power plant outages**: For each power plant, the outages are simulated based on a preliminary dispatch schedule and power plant outage probabilities.

- **Balance perimeter**: The deviation of generation and load in one market area resulting from dispatch schedules between two trading products of 15 min is being simulated based on a preliminary unit dispatch.

- **Forecast error of load**: The time variant forecast error of the load is simulated similar to the RES forecast error. Additionally, the load noise is simulated for each time step based on a Gaussian distribution.

Afterwards, all simulated imbalance time series are analyzed resulting in imbalance distribution curves for each hour. Like shown in Figure 3.1, the demand for positive and negative reserve capacity is calculated for each reserve quality in an hourly time pattern in order to meet a specific security level.

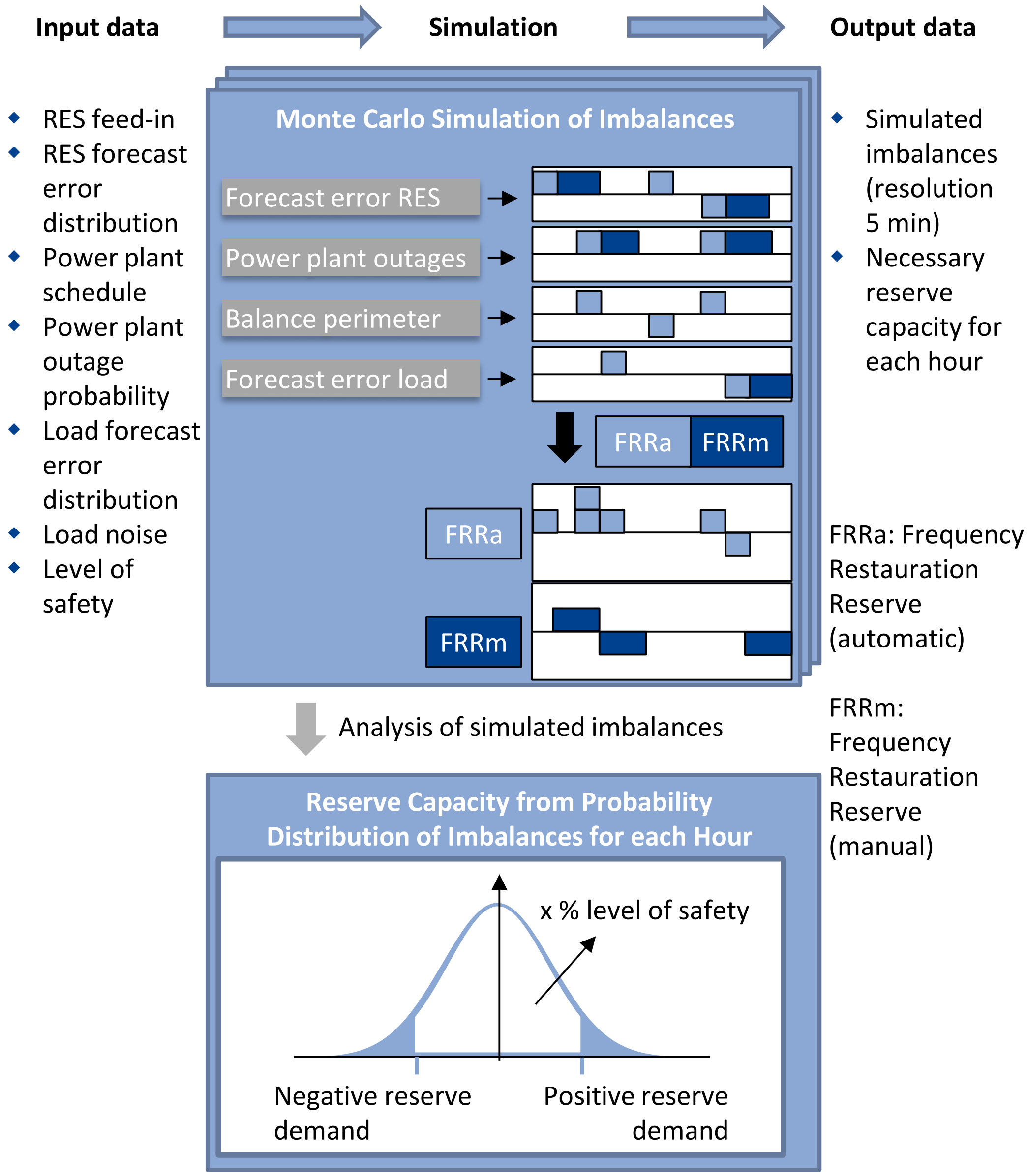

Figure 3.1: Determination of reserve demand method

3.2 Market Simulation

The market simulation is implemented by use of the methods for power generation planning and trading developed at IAEW over the last decades [2] [3]. It has been well tested and applied in several studies with transmission system operators (e.g. German Grid Development plan, NEP, 2012 & 2013), utilities and regulators in Germany as well as other European countries.

3.2.1 Scope of the Model, Input and Output Data

The market model set up as applied in this study contains an explicit model of the 16 European countries highlighted in color in the map in Figure 3.2 for the year 2012. The set of input data required to perform a market simulation of the European generation system comprises

- Hourly time series of the demand,
- Hourly time series of heat-led combined heat and power (CHP) plants and other must-run-generation as run-of-river power stations, wind, photovoltaic or concentrated solar power plants (CSP),
- Prices of primary energies (including transport and taxes) and CO_2-prices,
- Where applicable: constraints for primary energies (e. g. max. output of lignite mines),
- Requirements of reserve capacities for all market areas,
- For (pump) storage plants: reservoir size/storage volume, natural inflow and head of water as well as power, type of machine and efficiency factors of pumps und turbines,
- For thermal power plants: maximum power output, type of primary energy, type of machine (gas turbine, steam turbine, cogeneration), energy dependent operating costs, availability, efficiency at rated power, minimum power output, minimum up- and down-times, start-up costs,
- Hourly power exchange with neighboring countries beyond the scope of the survey (e.g. Iberian Peninsula).

Results of the simulation are the hourly power plant dispatch per unit, cross-border power exchanges and market prices for electricity under the assumption of perfect competition, total market transparency and with disregard of market participant's trading strategies.

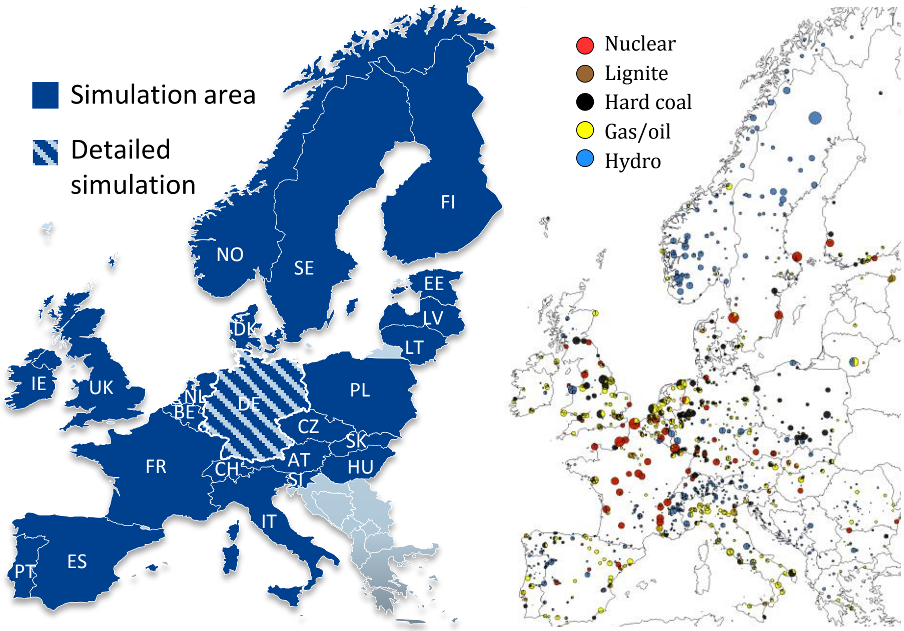

Figure 3.2: Countries considered in the market model

IAEW derives all the input data listed above from data collection from public sources as well as input data exchanges with EON and SINTEF.

3.2.2 General Approach of the Market Simulation Method

IAEW implemented the market simulation by use of the methods for power generation planning and trading developed over the past decades. On the basis of the input data described above such as thermal and hydropower plants including technical constraints, prices for primary energy, the demand for electricity and the cross-border transfer capacities, the simulation of a power market is performed. The simulation minimizes the total costs for power production in an economic sense under consideration of technical restrictions. The following listing features its key characteristics:

- Explicit modeling of time coupling between the basins of (pumped) hydro storage power plants.
- Optimization under perfect foresight; i.e. the cost minimal dispatch is calculated disregarding uncertainty on load and renewable energy sources (RES).
- The model can detect and remedy RES driven overrun of market areas.
- Under the assumption of efficient markets, day ahead and intraday market are not modeled as separate stages because it is assumed that in the end the dispatch resulting from the markets is close to the cost minimal dispatch.
- Requirements for reserve capacity (needed e.g. for the sudden unavailability of generation units or load changes) are modeled as boundary conditions for the optimization. Hydropower plants, gas turbines with quick start up ability and other thermal power plants operated below their maximum power can provide the positive reserve capacity while hydraulic power plants and thermal power operating above their minimal power output can provide negative reserve.
- This study considers no utilization of the reserve capacity.
- The simulation has on hourly time pattern.

3.2.3 Description of the Algorithm

Due to the complexity of the optimization problem, especially because of time-linking constraints in the management of storage power stations and in the minimum operating and downtimes of thermal power plants, a closed-loop formulation is not possible. Therefore, IAEW bases the market simulation method on a multi-stage approach. Furthermore, the optimization performs under perfect foresight, i.e. the algorithms "know" the load and RES time series at the beginning of the optimization.

The simulation of the optimal power plant dispatch contains three main steps. Figure 3.3 gives an overview of the overall procedure of the market simulation method. After reading and preparing the input data, the first step is to calculate an optimized power exchange schedule between the countries of the considered system with the objective of minimizing the total generation costs to supply the demand. In order to solve the optimization problem, a linear programming approach is used. Boundary conditions are the maximum transfer capacities and the maximum outputs of power plants. The startup of a power plant is a binary (yes or no) decision and neglected in this step of the market simulation method. The calculated exchange schedules are the initial solution for the following steps of the method.

The second step consists in determining the start-up decisions of thermal power plants for each country, making use of the power exchange schedule calculated in the previous step. In order to be able to solve the problem in a timely manner, the method subdivides the overall problem in several sub problems using a Lagrangian relaxation. That is a decomposition approach and based on the idea of reducing the main problem to less-dimensional sub problems. These sub problems are solved independently and are then superiorly coordinated to fit the linking constraints. So-called Lagrangian multipliers realize the coordination of the sub problems, which change their values in each iteration depending on the current solution. By iterative repetition of solving and coordinating the sub problems, the method reaches convergence and therefore an optimum of the entire problem.

In the case of market simulation, the optimization task is decomposed in order to be able to conduct the optimization for different types of plants with different algorithms adapted to the respective problems. Hydropower plants are thus optimized by using linear programming and thermal power plants by dynamic programming. Dynamic programming determines the optimal dispatch for each power plant under consideration of start-up costs as well as minimum operating and downtimes. The compliance with all those constraints needing a consideration of the entire system is assured by the coordination via Lagrange relaxation.

Due to the relaxation of system coupling constraints, the optimization does not necessarily comply with all constraints in each time interval with limited computation time. Therefore, only integer decisions such as thermal unit commitment regarding time constraints and generation boundaries are adopted from the second optimization stage. Hence, the third optimization stage solves the remaining continuous optimization problem in a closed-loop approach in order to assure the compliance with time and system coupling constraints. The third step (cross-border load distribution) is applied to calculate the power exchange schedule between the countries of the system in consideration of the technical constraints of thermal power plants. The main results of the closed-loop optimization are a system-wide power plant dispatch at minimum costs to supply the power demand, the cross-border power exchanges and the power prices in each market area.

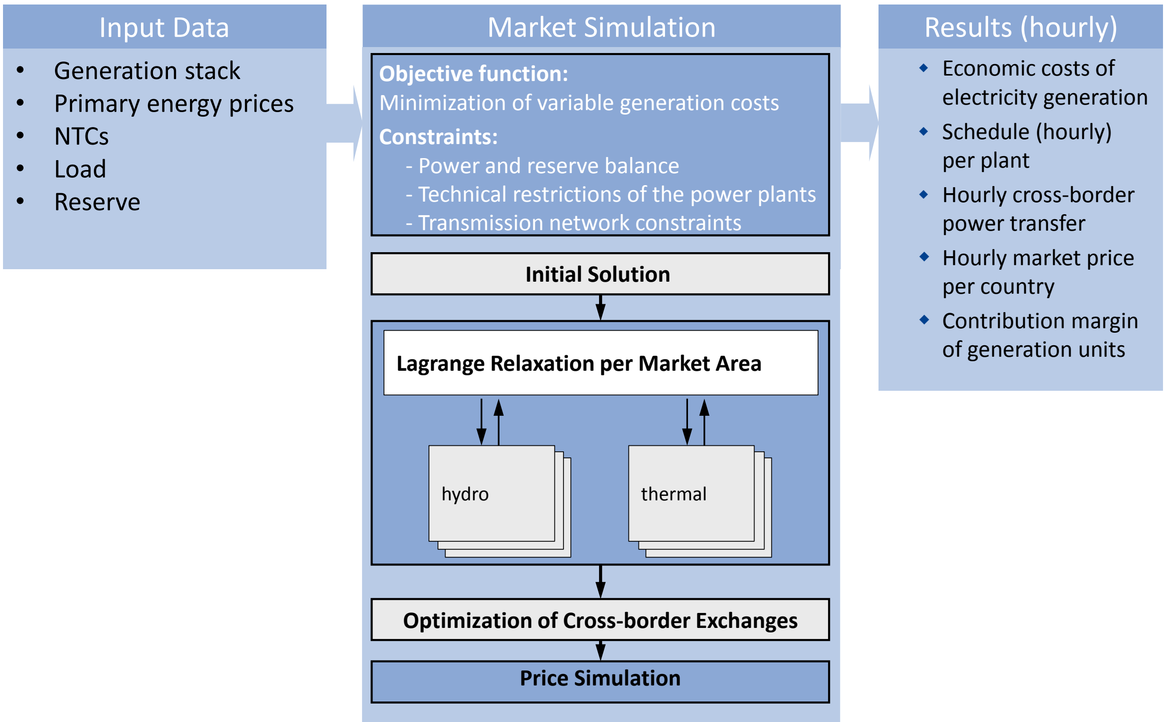

Figure 3.3: Market simulation method

In spite of the differences between model and reality, power plant schedules calculated from the market simulation are reasonable input data to network simulations because they represent cost minimal, technically feasible schedules that should result from a near-ideal market in reality as well.

3.3 Detailed Simulation of German Markets

The German markets are simulated in high detail in this study. This includes the spot market and the reserve markets for primary (PR) secondary (SR) and tertiary reserve (TR). In order to account for feed-in ramping of RES a trading scheme of 15 minutes is simulated. Therefore, all load and feed-in time series have to be modeled in the same time pattern.

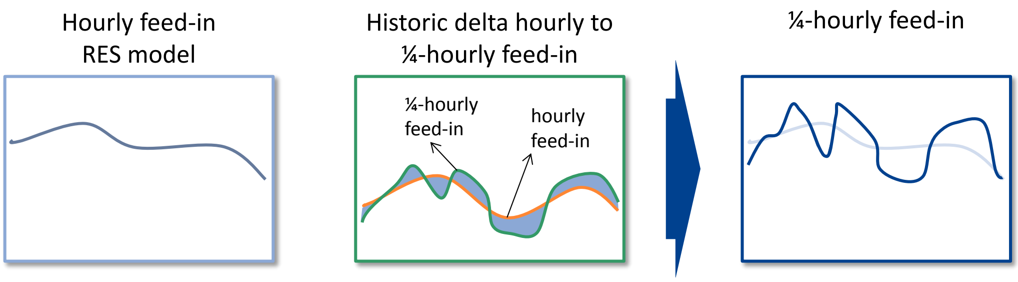

Figure 3.4: Modeling RES Feed-in with ¼-hourly Resolution

Figure 3.4 depicts the approach on how the intermittent RES feed-in is being modeled. The approach uses the hourly values from the European simulation and modulates it with ¼-hourly deviations. These deviations are calculated from historic deviations of historic feed-in between hourly and ¼-hourly values scaled with the respective generation capacity. That way the simulated prices reflect realistic feed-in volatility and are consistent to the European market simulation in hourly time pattern.

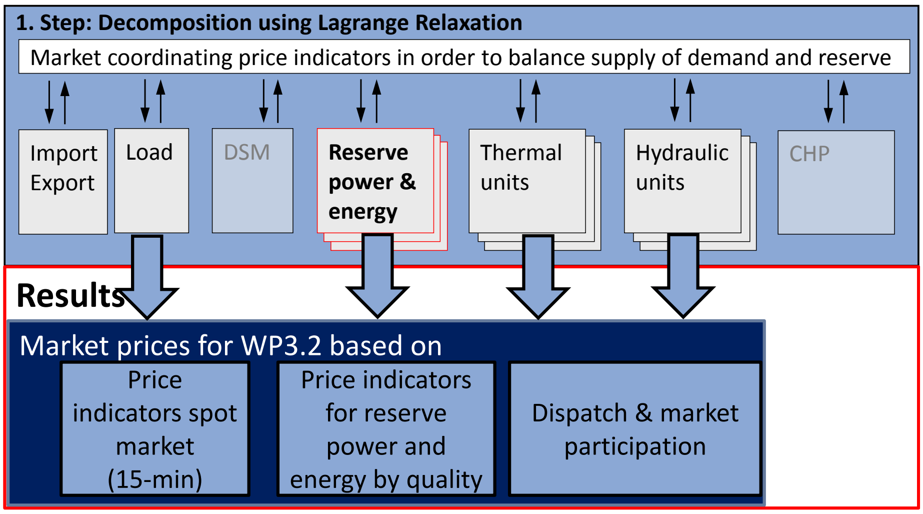

Figure 3.5: Modeling German spot- and reserve market in high detail

The detailed simulation, similar to the European simulation, consists of a dispatch optimization based on a decomposition with Lagrangian relaxation (see Paragraph 3.2.3). In addition, the reserve markets are simulated separated into PR, SR and TR. The power plants load gradients in relation to the respective activation time of the reserve markets determine the potential of reserve provision for each generation unit. Since the simulation scope is limited to the German market area, hourly imports and exports are an input data (as a result of the European simulation) and are fixed in the simulation. Figure 3.5 gives an overview of the detailed market simulation approach. For each time interval and market there is one coordinating variable used in the Lagrangian relaxation to ensure the coverage of the market. The resulting value of each coordinating variable (energy, reserve power and reserve energy) leading to market clearance can therefore be interpreted as a price indicator for a uniform-pricing scheme.

3.4 Portfolio Optimization

The unit dispatch of power plant portfolios is optimized by maximizing the contribution margin (CM) that can be generated by trading at various markets for electricity and reserve products. In the last years, a portfolio dispatch and trading optimization method has been developed at IAEW that is based on a closed-loop approach.

In a variable time[1] pattern the dispatch of thermal power plants, RES and storages as well as provision of various reserve qualities is being optimized. In addition to technical restrictions of the generation units, market restrictions like product definitions and minimum or maximum trade volumes are taken into account. Figure 3.6 gives an overview of the optimization method.

[1] Usually a time pattern of 1h or 15 min is applied.

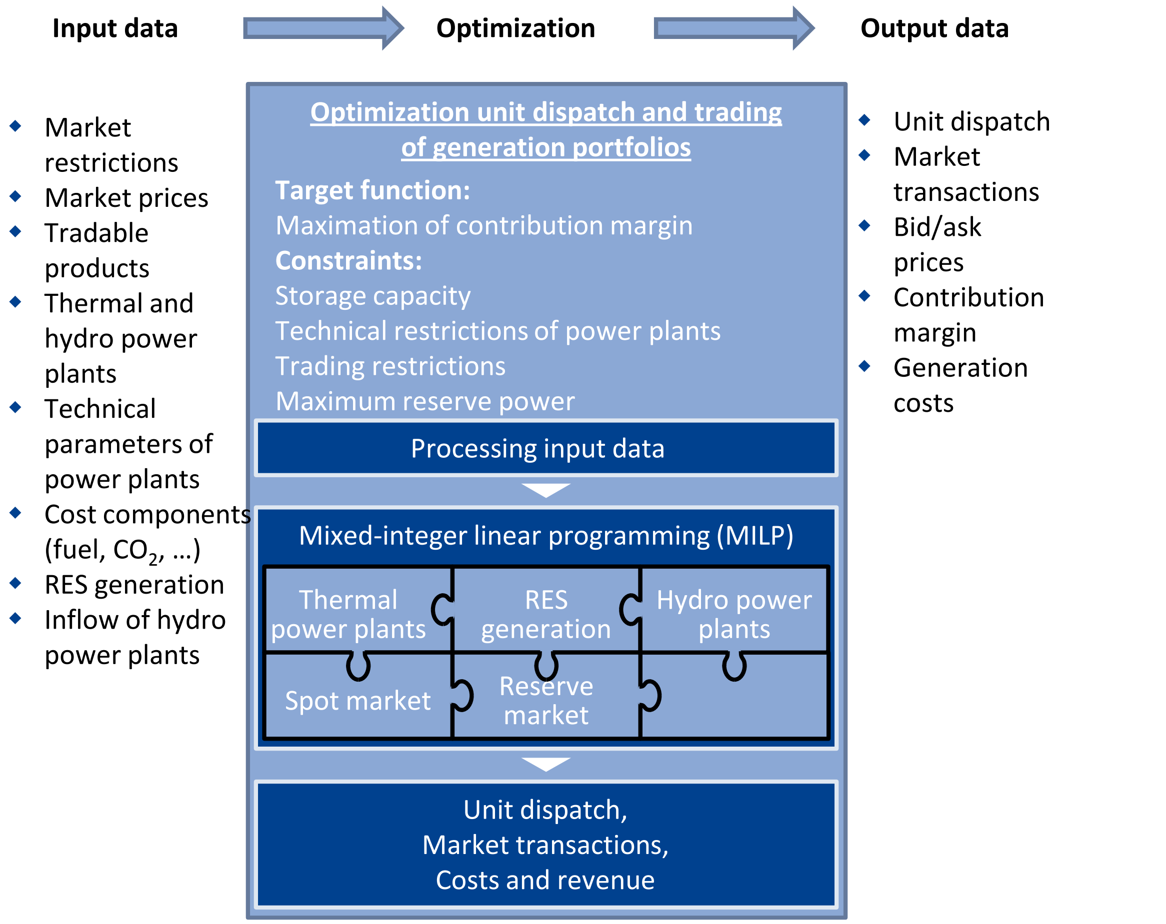

Figure 3.6: Portfolio optimization method

For the simulated time period, RES feed-in can either be modelled deterministically or as feed-in scenarios for a stochastic optimization under uncertainties. When taking into account prognosis errors and different market stages the portfolio dispatch optimization is applied to every market stage. Figure 3.7 gives an example of different stages of marketing a portfolio that consists of RES and flexible units. First, the day ahead feed-in prognosis is used to optimize the trading at the day ahead market. When closer to the time of delivery the feed-in prognosis is improved. In order to minimize the deviation of the scheduled dispatch and the real dispatch the updated prognosis is traded on the intraday market. All deviations between the last prognosis and the actual feed-in either have to be balanced by flexible units in the portfolio or by using of possibly expansive balancing energy, which is provided by the TSO. This results in an additional benefit of flexibility (e.g. from pumped-storage plants) in a portfolio with intermittent feed-in.

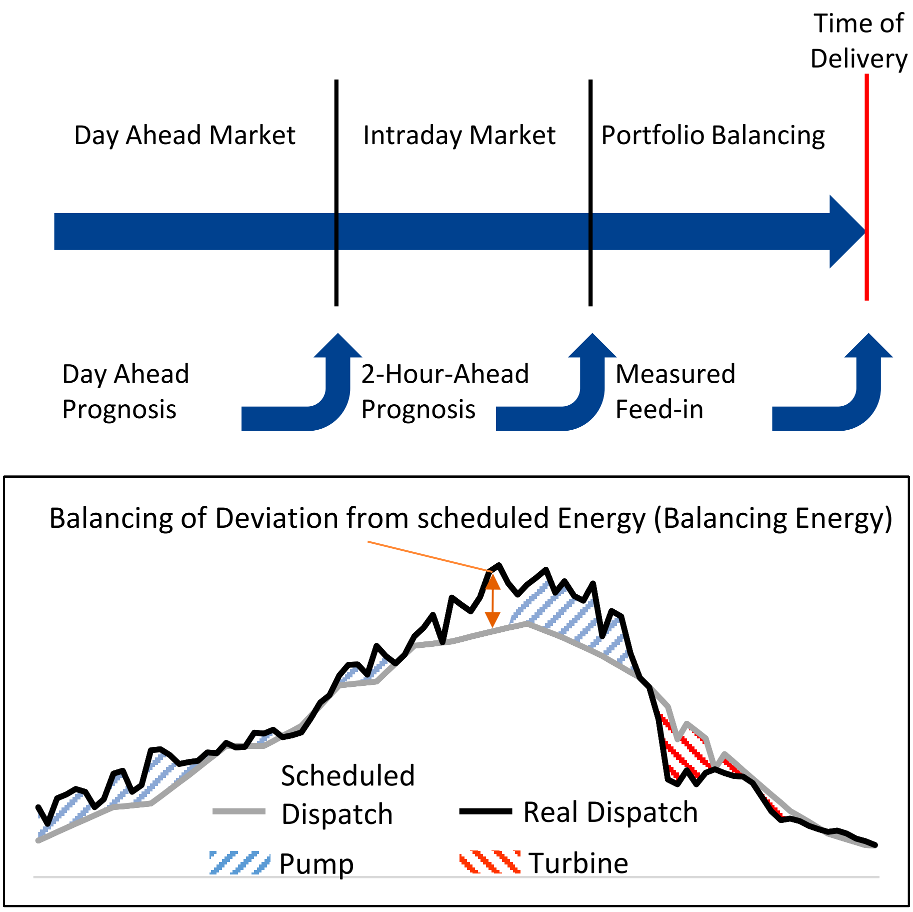

Figure 3.7: Approach for prognosis errors and marketing stages

In order to assess this impact this procedure is approximated by performing one portfolio optimization for each step. The first step consists of the day-ahead prognosis as a feed-in time series as well as the day-ahead and reserve market prices as market parameters. The second step uses the intraday prices and an updated feed-in time series. The result of both steps is the traded energy in each time interval that has to be fulfilled or traded in the following simulation step. Subject to the last simulation step is the actual unit dispatch. The last optimization step is performed with no degree of freedom for trading since market gate closure is reached. Thus, the goal is to optimize portfolio balancing to avoid payments for balancing energy. The result of the 3-step approach is the energy traded day-ahead and intraday as well as the needed balancing energy.

4 Input Data

4.1 Scenarios for the European Power System

The study regards two different scenarios for the European Power System (see also Figure 3.2) in the year 2050, which base on the "EU Trends to 2050" published by the European Commission [4]. The first scenario (B – "Big Storage") reflects a European power system where Norwegian hydropower provides significant shares of the flexibility and storage needs in (Northern) Europe and thus acts as a big hydro battery for Europe. In contradiction, in the second scenario (C – "Niche Storage") Norwegian hydropower mainly provides long-term balancing as a storage device while the flexibility in the power systems in the other European countries themselves is higher than in scenario B (see Figure 4.1). The following sub-chapters describe the assumed scenarios more detailed.

	Scenario B „Big Storage“	Scenario C „Niche Storage“
Conventional generation	• Reduced fossil/nuclear capacity by 10% • 60 GW of hydro power in Norway • Secured peak load in Europe	• Increased hydro capacity by 10% • 50 GW of hydro power in Norway • Secured peak load for each country
Alternative flexibilities	• Little DSM and inflexible CHP • No PtG storages • Passive operation of distributed storages	• Increased DSM and flexible CHP • 20 GW of PtG storages in Europe • Market-orientated operation of distributed storages
Transmission capacities	• Up to 30 GW cable capacity from and to Norway necessary for export • Increased transfer capacities by 50%	• Up to 20 GW cable capacity from and to Norway necessary for export
Integration of Markets	• Cross-border reserve markets → Optimal allocation of resources	• National reserve markets

Figure 4.1: Main Differences between Scenario B and C

4.1.1 Generation Stack

The assumed development of RES capacity as shown in Figure 4.2 is derived from the EU Trends study regarding the distribution of the different technologies. The installed capacity is adjusted by an increase so that Germany reaches its target according to the energy concept of the federal government [5] of achieving an RES share of 80% of the electricity demand in the year 2050. The installed RES capacity in the other European countries is increased with the same ratio as in Germany. This results in a European-wide RES share of 69% of the electricity demand. The feed-in of RES is derived from a model using historic weather data from the year 2008. The model uses data such as temperature, solar irradiation and wind speed to generate hourly feed-in time series for all nodes in the transmission grid, which are afterwards aggregated for each country.

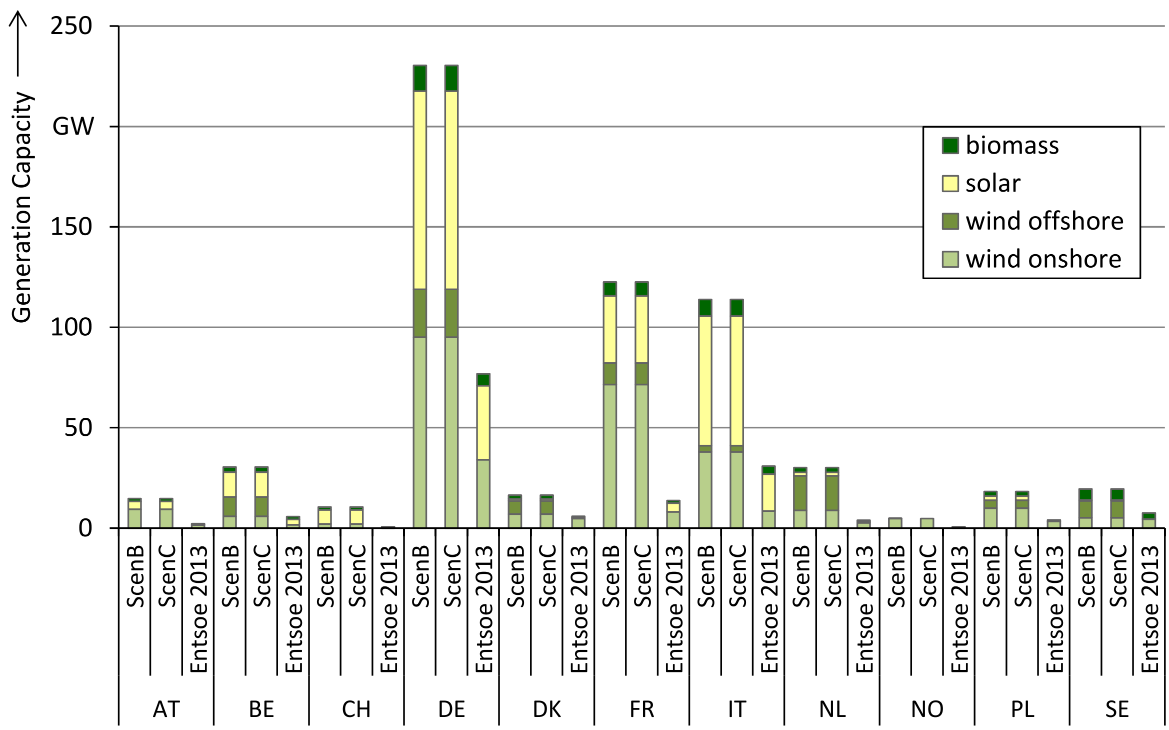

Figure 4.2: RES capacity today and assumptions for regarded scenarios

The conventional generation stack differs slightly between the regarded scenarios (see Figure 4.3). While scenario C represents mainly the assumptions according to the EU Trends study, scenario B has a reduced conventional generation capacity. On the one hand, the fossil and nuclear capacity is reduced by 10% and on the other hand, not utilized power plants (mostly open cycle gas turbines) are neglected in this scenario. The not utilized power plants were identified in a preliminary examination. The reason for this reduction is that the main idea of scenario B is that Norwegian hydropower provides flexibility for Europe and therefore significant backup power plants are not necessary in the other European countries. Furthermore, both scenarios assume a reduction of nuclear power capacity by approx. 65 GW in comparison to the EU Trends study values. This reduction corresponds to the assumed increase of RES capacity in terms of potential yearly power generation. Whilst the installed generation capacity and reservoir capacity in scenario B reflects the value of the EU Trends study, scenario C assumes additional hydropower in the European generation stack leading to an increase of 10 % in generation and storage capacity. Regarding Norway, both scenarios imply an expansion of hydropower plants increasing the turbine capacity by 20 GW in scenario C and 30 GW in scenario B. In addition, the pumping capacity of 8.7 GW in scenario C and 13.7 GW in scenario B is installed at existing hydropower plants. This expansion does not assume the construction of new power plants but the expansion of existing plants by new pumps and turbines as well as raising of dams. The resulting turbine capacity raises from about 30 GW today to 59.7 GW in scenario B and 49.7 GW in scenario C. The installed capacity of pumps rises to 15.4 GW in scenario B and 10.4 GW in scenario C. In both scenarios a total reservoir storage capacity of 85 TWh is assumed for Norwegian hydropower which is no significant increase in comparison to today.

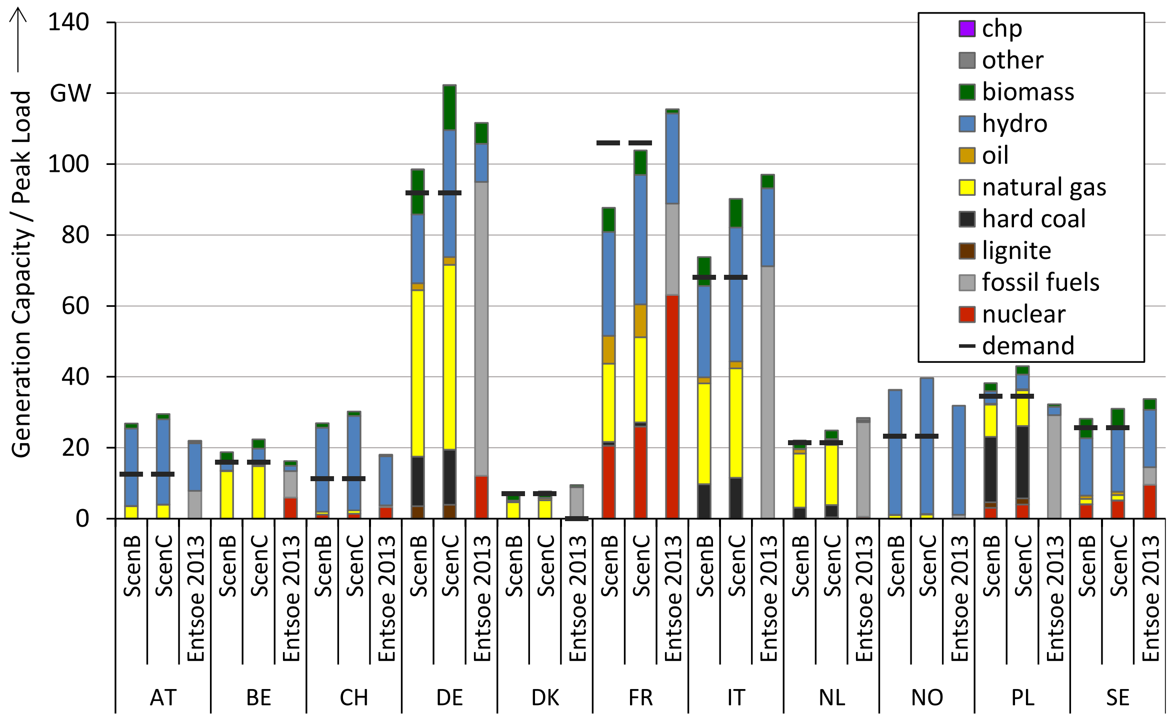

Figure 4.3: Conventional generation capacity today and assumptions for regarded scenarios

4.1.2 Power System Flexibilities

The power system in the year 2050 has to cope with the large amount of intermittent feed-in and thus needs flexibilities. These flexibilities can concern the demand and supply side of the power system as well as storages. On the demand side, load shifting by means of demand side management (DSM) is most important. The parametrization of the DSM potential bases on the Agora study about power storages [6]. Since the realized potential in the Agora study seems to be quite optimistic, the maximum shifting capacity is reduced for the investigation in this study by 75% in scenario B and by 50% in scenario C. The assumed maximum shifting time is 2 h in scenario B and 3 h on scenario C while the costs for shifting are set to 50 €/MWh in both scenarios. These costs for load shifting reflect a value in-between the assumptions of the Agora study [6] where a range of 10 to 400 €/MWh is assumed.

On the supply side, major flexibility gains are expected to derive from combined heat and power (CHP) generation. For example, heat storages enable a decoupling of power and heat generation. Furthermore, Power-to-Heat (PtH) applications and gas boilers can additionally increase the flexibility of CHP generation. In this study, the total CHP capacity for each country is derived from the EU Trends study and assumed to be able to cover 50% of the maximum thermal load. The share of flexible CHP generation is set to 60% in scenario B and 90% in scenario C. For the inflexible part of the CHP generation, the model provides hourly feed-in values subject to the temperature for each regarded country. Gas boilers are assumed to be able to cover 100% of the thermal peak load while this value is set to 15% for PtH. Heat storages are parametrized so that they can store the heat production from the flexible CHP plants for a duration of 2 h.

Regarding storages, this study differentiates between storages at distribution and transmission grid level. At distribution grid level, batteries are most suitable for storage and often combined with photovoltaic (PV) plants. Their capacity is assumed to a share of 8% of the installed PV capacity. In scenario B, these batteries are operated only depending on the solar power generation reducing the consumers load from the grid. In scenario C, the batteries are participating on the power market and are therefore included in the optimization. At transmission grid level the considered storages are pumped hydropower plants in both scenarios and Power-to-Gas (PtG) plants in scenario C only. Hydropower plants are parametrized according to the EU Trends study with additional updates from the IAEW power plant database. PtG storages use surplus power in order to produce synthetic gas. For that reason, their capacity is determined by preliminary investigations estimating the surplus power for each country. The capacity is then set to the value of surplus power that occurs in at least 2,000 h/a (see Table 4.1). This way a significant amount of full load hours for the PtG plants can be guaranteed.

Table 4.1: PtG capacity in scenario C

	DE	DK	FI	LV	NL	PT	UK
PtG [GW_{el}]	2.5	4.3	0.5	0.9	4.7	0.5	6.7

4.1.3 Primary Energy Prices

Prices for primary energy have a high impact on the generation costs of thermal power plants. The assumed prices in both scenarios are based on the EU Trends study [4]. Table 4.2 gives an overview of the costs for uranium, coal, natural gas and oil as well as for CO_2 emission certificates.

Table 4.2: Prices for primary energy and CO_2 emission certificates

Primary Energy		2013 Historic	2050 Scenario B	2050 Scenario C
Uranium	$\frac{€}{GJ}$	0.48	0.48	0.48
Lignite		0.45	0.45	0.45
Hard Coal		3.57	5.04	5.04
Natural Gas		8.24	9.96	9.96
Oil		13.77	17.47	17.47
CO_2 Emission Certificates	$\frac{€}{t}$	4.50	75.19	75.19

The scenario assumes a moderate increase of prices for hard coal, gas and oil while prices for CO_2 emission certificates increase due to the emission goals set by the EU.

4.1.4 Transmission Capacities

The available transfer capacities in terms of Net Transfer Capacities (NTC) between the European market areas are based on the planned transmission grid development published by ENTSO-E in the Ten Year Network Development Plan (TYNDP) [7]. While scenario C considers all lines planned in the TYNDP (also long-term projects), scenario B assumes additional grid expansion with an NTC increase of 50% on all market area borders. Due to the expansion of hydropower in Norway in both scenarios, the NTC from Scandinavia to the rest of Europa needs to be increased even further. This increase is parametrized in preliminary investigations so that congestion does not appear in more than 30% of the hours in a year. Figure 4.4 compares the necessary increase in order to integrate the hydropower expansion from scenario C into the European markets. The transfer capacities of the scenario without hydropower expansion only include cable projects already planned today.

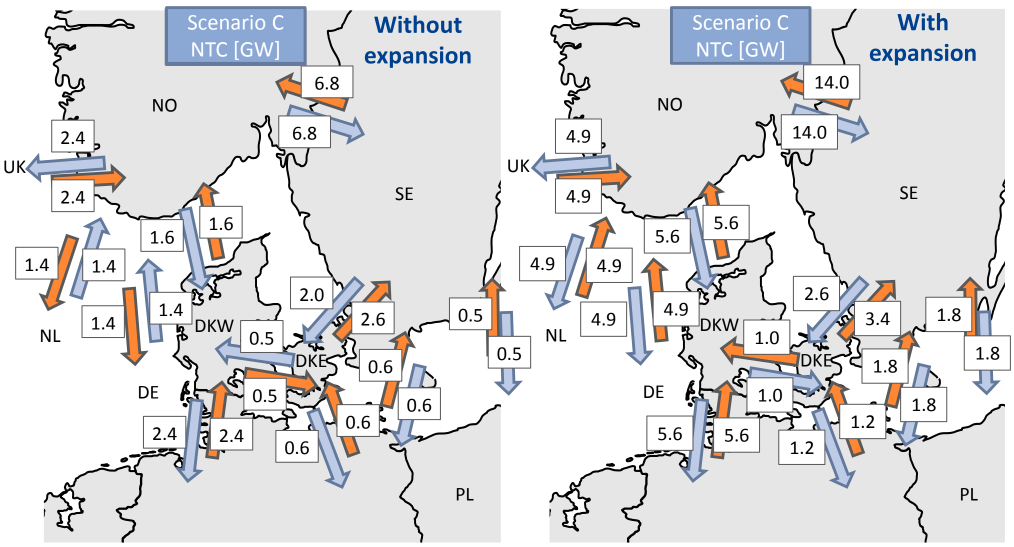

Figure 4.4: Comparison of transfer capacities with and without expansion of hydropower and transfer capacities in scenario C

Figure 4.5 shows the resulting NTC for Scandinavia under consideration of the hydropower expansion. Tables containing all NTC for both scenarios as well as a comparison with today's NTC values can be found in the appendix.

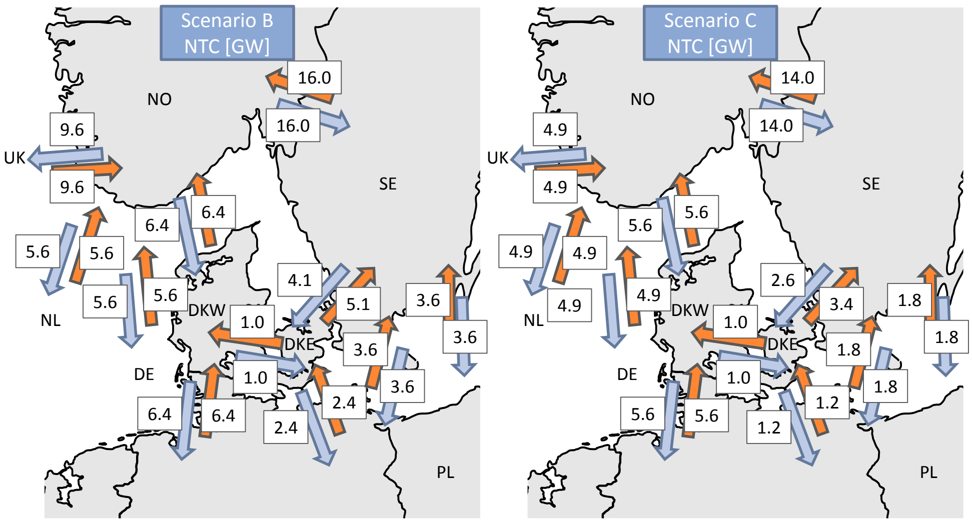

Figure 4.5: Transfer capacities from and to Scandinavia

The utilization of the transfer capacities differs for the two scenarios. In scenario C, they are only used to optimize the exchange of scheduled energy (see "reference" case in Chapter 2). Scenario B assumes a stronger European linking of the power markets and thus considers the optimization of scheduled energy and reserve (see "optimal" case in Chapter 2).

4.1.5 Electricity Demand

The demand for electricity is derived from the EU Trends study and displayed in Figure 4.6. The study assumes a slight increase in electricity consumption resulting from new consumers like battery vehicles. For transforming the yearly electricity demand into hourly load series required by the market simulation the historical load series of the year 2008 for each country are scaled. Structural changes of the load are approximated by the consideration of DSM potentials as described in Chapter 4.1.2.

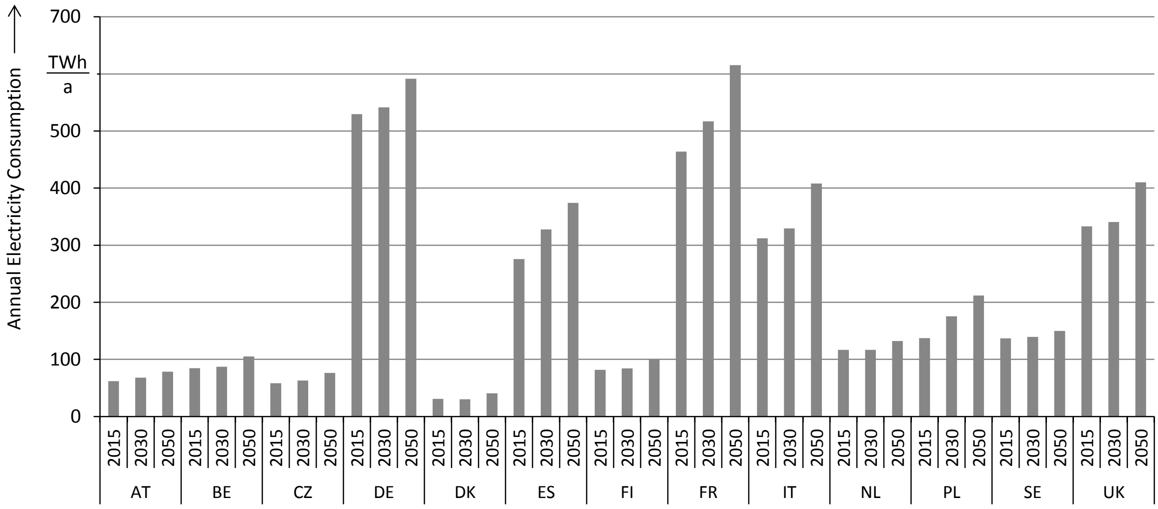

Figure 4.6: Development of electricity demand

4.2 Generation Portfolios

The microeconomic part of the study focusses on the effect for German generation portfolios of having access to Norwegian hydropower plants. Two different generation portfolios are considered in the investigations. The first portfolio ("RES") has a total capacity of 1 GW and consists of RES generation from solar, wind and biomass. Regarding reserve provision, it is assumed that wind power participates in the tertiary reserve (TR) market. Since biomass is dispatchable, these plants are additionally considered for secondary reserve (SR) provision. The second portfolio ("Mixed") consists of RES and conventional generation units. In this portfolio, the RES capacity has the same distribution on the different technologies but has half of the capacity. The additional conventional generation is coming from gas-fired open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT). The capacity of CCGT is parametrized so that the yearly power generation is similar to the RES generation in the mixed portfolio. Additionally, OCGT are added with the same capacity as the CCGT. This way the yearly power generation of both portfolios is expected to be similar in the portfolio optimization. Both, OCGT and CCGT can participate in the primary reserve (PR) as well as in SR and TR markets.

Table 4.3: Regarded generation portfolios

	Solar	Wind	Biomass	OCGT	CCGT
RES [MW]	429	516	55	-	-
Mixed [MW]	214.5	258	22.5	155	150
Reserve provision	-	TR	SR, TR	PR, SR, TR	PR, SR, TR

In the investigations, both portfolios are also simulated in combination with a Norwegian pumped storage comprising turbine and pump capacity of 1 GW and 327 GWh of storage capacity. The natural inflow into the storage (equivalent to the average inflow of the Norwegian pumped storages) is assumed to 2.16 TWh/a.

5 Results

5.1 Benefit of Additional Norwegian Hydropower for Europe

In order to quantify the additional benefit from the expansion of Norwegian hydropower capacity, the effects of increased turbine and pump capacity on the European power system is analyzed. Therefore, Figure 5.1 shows the difference in power generation with the additional hydropower capacity for both scenarios.

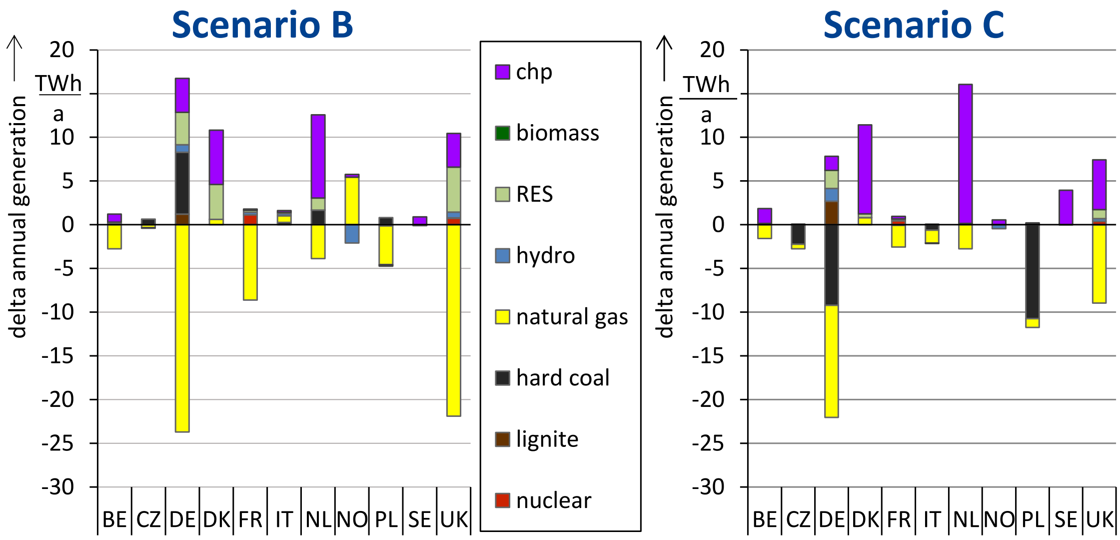

Figure 5.1: Difference in power generation with additional hydropower capacity in Norway

The additional hydropower capacity results in a reduction of RES curtailments due to an increase of pump capacity in Norway and exchange capacity from and to Scandinavia. The system-wide increase of RES generation amounts to 15 TWh/a in scenario B and 4 TWh/a in scenario C. This corresponds to an integration of 65% of the curtailed RES generation in scenario B and 42% in scenario C. In addition to the integration of RES, expensive generation from natural gas power plants is substituted by cheaper generation from lignite and nuclear power plants by the expansion of hydropower plants in Norway. Additional significant changes occur in CHP generation. The additional integration of RES generation along with an increase of transmission capacities leads to a reduction of the utilization of electric heating and gas boilers. In return, the generation from conventional CHP plants increases.

The increase of hydropower capacity in Norway and the expansion of transmission capacities in the North Sea affects the power exchanges. Figure 5.2 shows the corresponding changes exemplarily for scenario B.

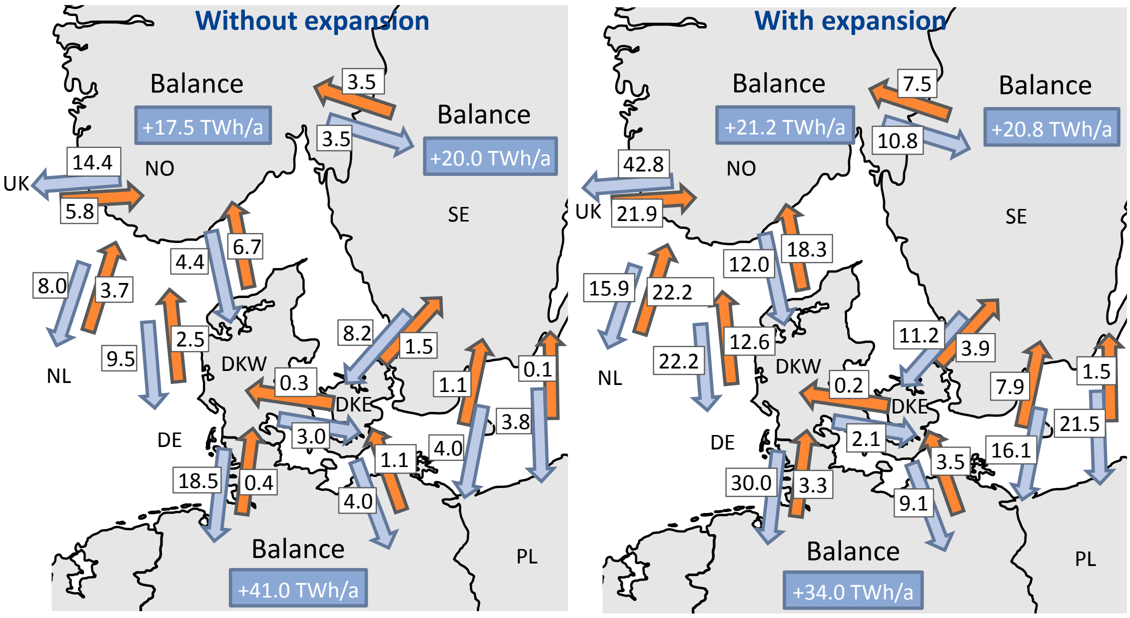

Figure 5.2: Power exchanges with and without hydropower expansion in Norway in [TWh/a] (scenario B)

The expansion of hydropower and transmission capacities leads to a significant increase of power exports from Scandinavia towards Europe on the one hand. Especially towards UK and Poland, the exports multiply. On the other hand, also imports rise to a similar extent as the exports. These imports mostly consist of RES generation from solar and wind power. Thus, the export balance is only slightly influenced by the hydropower expansion and mainly results from changes in CHP and natural gas power generation.

The change in power generation also affects the variable system costs as shown in Figure 5.3.

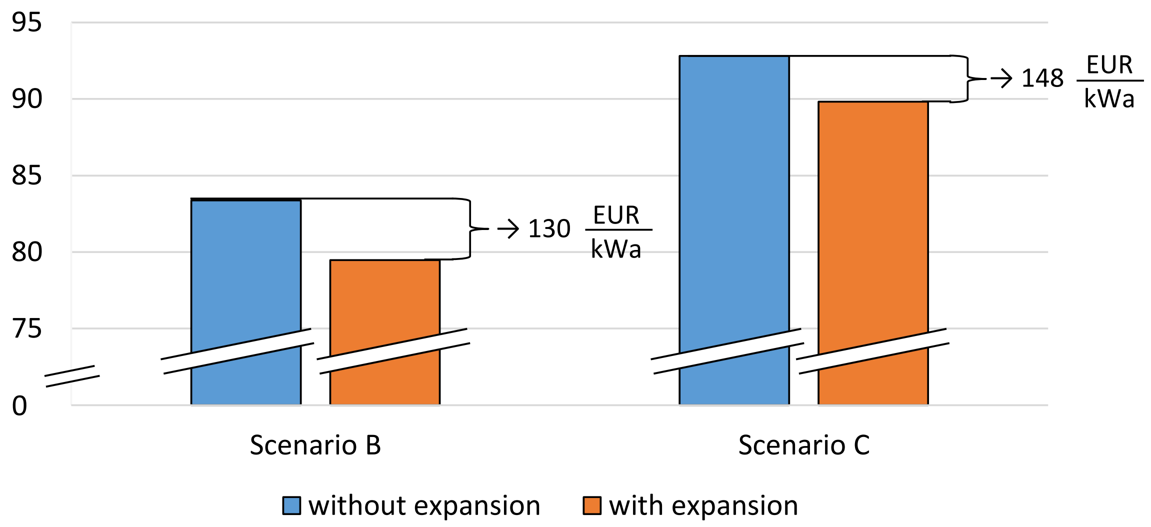

Figure 5.3: Impact on variable system cost by additional hydropower capacity

These costs decrease by 3.9 bn €/a in scenario B which represents 4.6% of the total costs. In scenario C, the cost reduction amounts to 3.0 bn €/a and thus 3.1% of the total variable system costs. The cost reduction mainly results from two different effects in the power generation. First, hydropower and especially pumped storage plants support the smoothening of the dispatch of conventional power plants and thus decrease generation costs. Second, pumped storage plants increase the integration of RES power generation into the system and thus avoid curtailments. With regard to the hydropower expansion, the change in total costs in scenario B means a specific cost reduction of 130 €/kWa for the turbine capacities and the corresponding pump and transmission capacities. In scenario C, the additional hydropower capacity in Norway is less than in scenario B. Thus, the specific additional value is higher in this scenario and a cost reduction of 148 €/kWa is reached. Over a period of 40 years and considering an interest rate of 5%, the specific cost reduction is 2,230 €/kW in scenario B and 2,540 €/kW in scenario C. The investment costs can be estimated to about 500 EUR/kW for the expansion of Norwegian hydropower plants [8] and about 1,000 EUR/kW for sea cables from Norway to Germany [9]. Thus, even when considering maintenance costs and additional grid expansion in Norway and Germany, the expansion of hydropower and cable capacity is likely to results in an economic benefit from a system point of view in the regarded scenario.

5.2 Macroeconomic Results – Base Case

5.2.1 Power Generation and Exchanges

The market simulation requires the necessary reserve provision as an input data, which is calculated for each hour and each market area by the method described in Chapter 3.1. The results of the reserve dimensioning for scenario B are shown exemplarily in Figure 5.4 for Germany and Norway. In the diagram, the blue bar represents the range and the circle the average calculated reserve power. It can be seen that the range and absolute value of SR and TR is higher than the ones of PR. The reason is that SR and TR are highly dependent on the intermittent feed-in of RES which also explains the increase in comparison to today's values. Since the necessary reserve power is mainly dependent on the RES capacity, the results for scenario C are very similar.

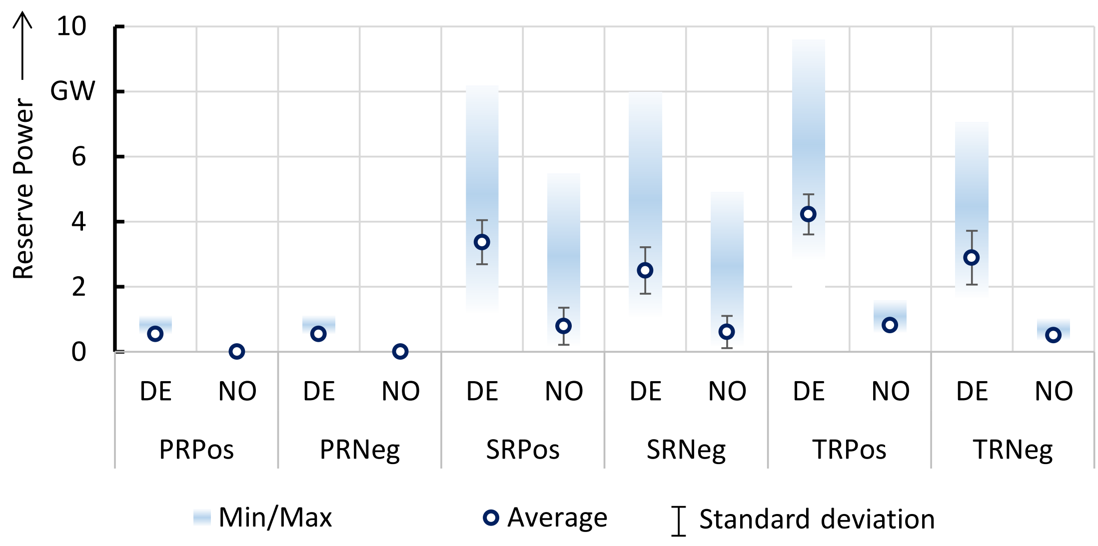

Figure 5.4: Required reserve power for Germany and Norway for scenario B

A major result of the market simulation is the power plant dispatch. Figure 5.5 shows the simulated aggregated power generation broken down to primary energy carriers in comparison to 2013 values for central and Northern Europe. Corresponding to the capacity development the energy transition in Europe leads to a switch from conventional to RES generation. Especially Germany, France and Great Britain have a large penetration of wind and solar power feed-in. The generation in Scandinavia mainly composes of hydropower and nuclear power generation but also solar and wind generation show a strong increase.

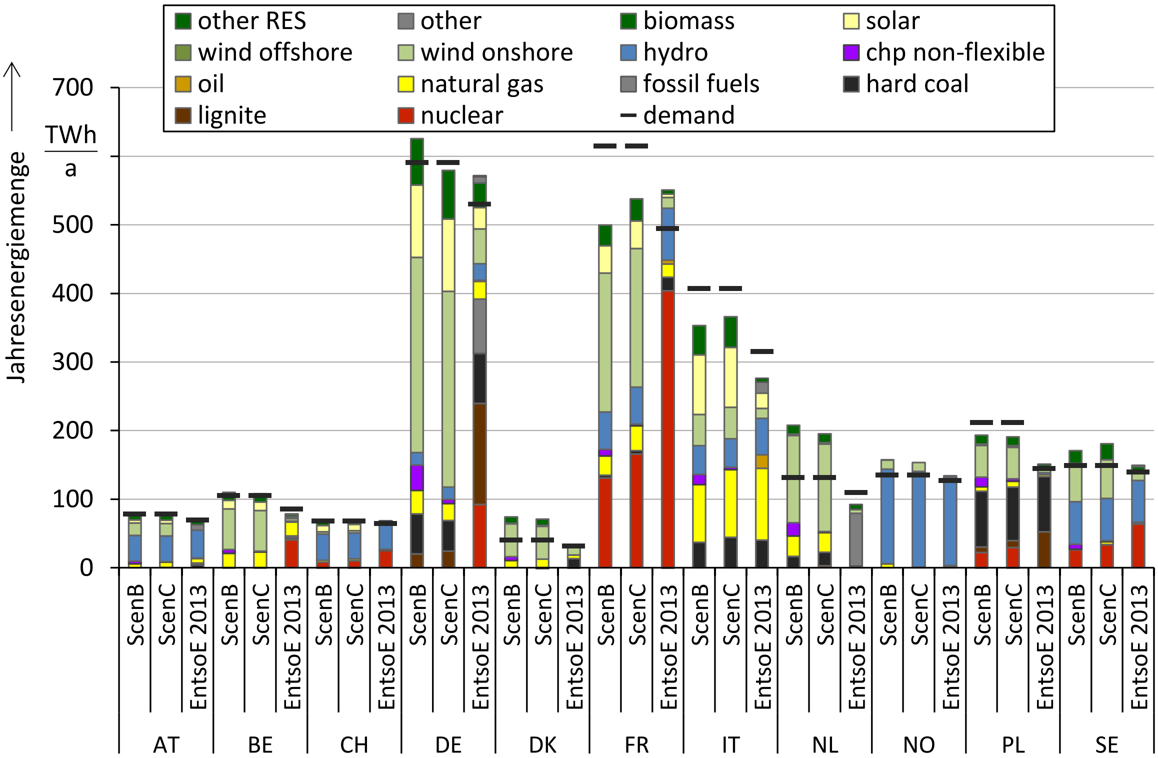

Figure 5.5: Power generation broke down to primary energy carriers

Figure 5.6 gives a more detailed analysis of the RES generation. Beside the distribution, also the share of RES of the electricity demand is displayed. The majority of the RES generation is coming from onshore and offshore wind power. A significant share of hydropower generation mainly occurs in Scandinavia and in countries with large mountainous areas such as Austria and Switzerland. In some countries like Norway and the Netherlands, the RES share exceeds 100% meaning that these countries will export electric energy in many hours or even have to curtail RES generation in situations with high wind and solar power feed-in. The slight variation between the two scenarios results from differences in the dispatch of flexible hydropower and biomass generation.

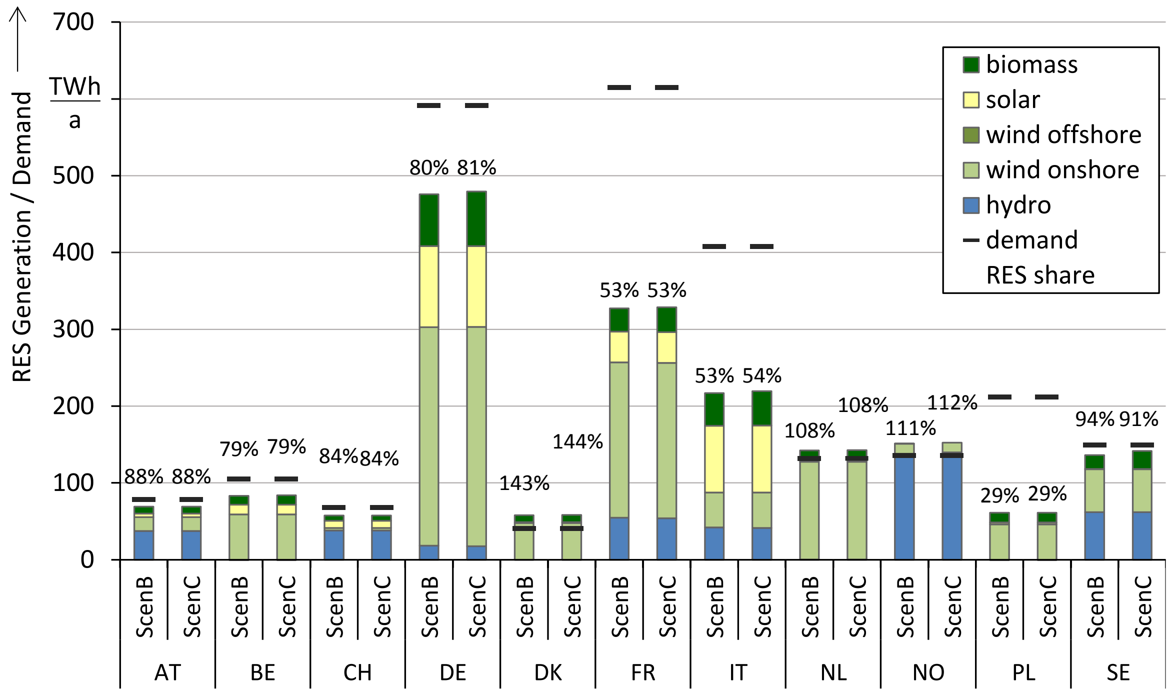

Figure 5.6: Share and distribution of RES generation

The large share of RES leads to surplus power generation in situations with high feed-in from wind and solar power. Depending on the transmission capacity to Norway, parts of this surplus generation is stored in the big Norwegian hydropower storages. However, in situations with grid congestions, alternative flexibilities have to be utilized inside the area where the surplus occurs. For both scenarios, Figure 5.7 shows the aggregated energy surplus, that cannot be used in the electricity sector but is utilized by PtG and PtH devices or has to be curtailed. Mainly due to the increased transmission capacities, the surplus in scenario B is lower than in scenario C for most of the countries. Most of the surpluses occur in Northern European countries, which also have the highest shares of RES. Parts of the surpluses are used to generate heat in PtH devices or to produce synthetic gas in PtG plants. Thus, the remaining surpluses are reduced and the necessary RES curtailment is minimized.

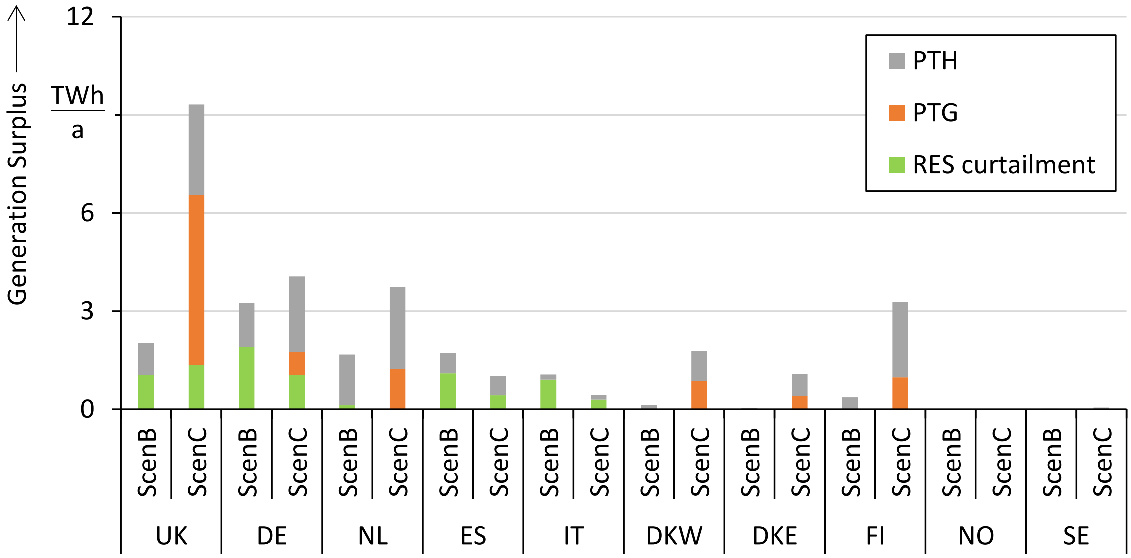

Figure 5.7: Energy surplus and utilization of PtG and PtH

The power exchanges between the European countries are important to balance intermittent RES feed-in. Figure 5.8 displays the power exchanges (in TWh/a) and the exchange balances for Scandinavia. It can be seen that the Scandinavian countries have a positive exchange balance and export to the countries in central Europe in most of the hours.

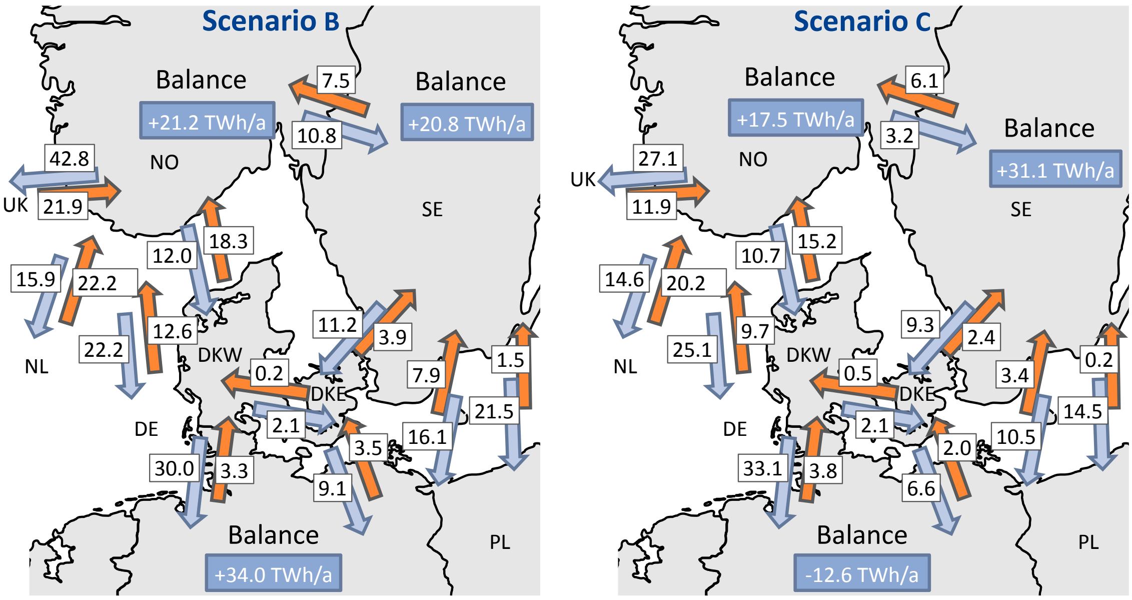

Figure 5.8: Power exchanges from and to Scandinavia in [TWh/a]

The exported energy mostly comes from hydropower and nuclear generation, which both have little marginal generation costs. However, there are also significant amounts of imports from central Europe to Scandinavia. These imports occur in situations with high RES feed-in when power surpluses are exported e.g. wind power from Germany as shown in Figure 5.9 for scenario B. The exchanges in scenario B are higher than in scenario C due to the increased NTC and the additional hydropower capacity in Norway.

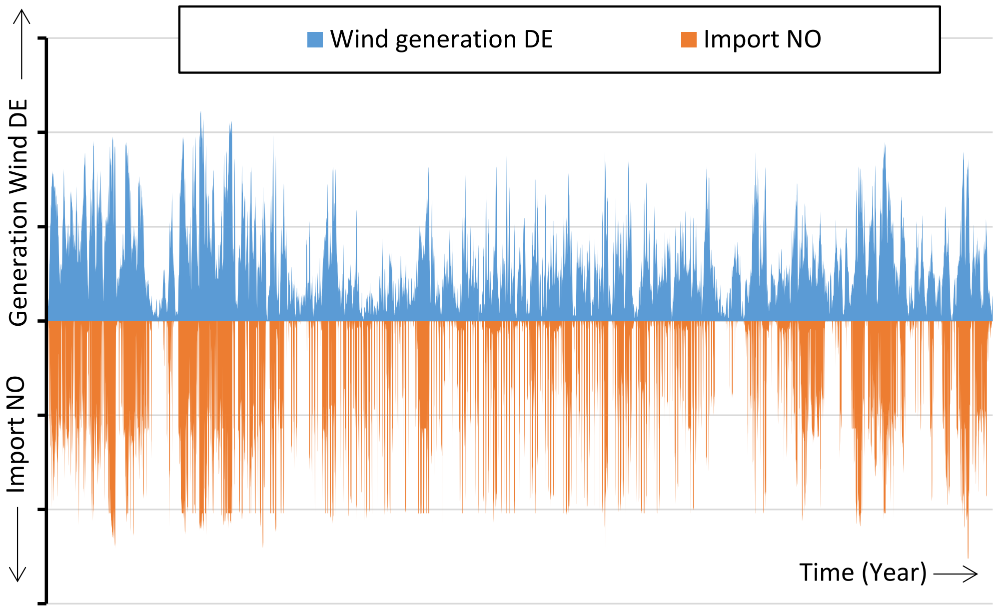

Figure 5.9: Correlation of wind power in Germany and Norwegian import (scenario B)

Figure 5.10 shows the aggregated dispatch of all turbines and pumps in Norway for both scenarios. Even though the installed capacity of pumped storage in scenario B (15.4 GW) is higher than in scenario C (10.4 GW), the storages are utilized in more hours in scenario B.

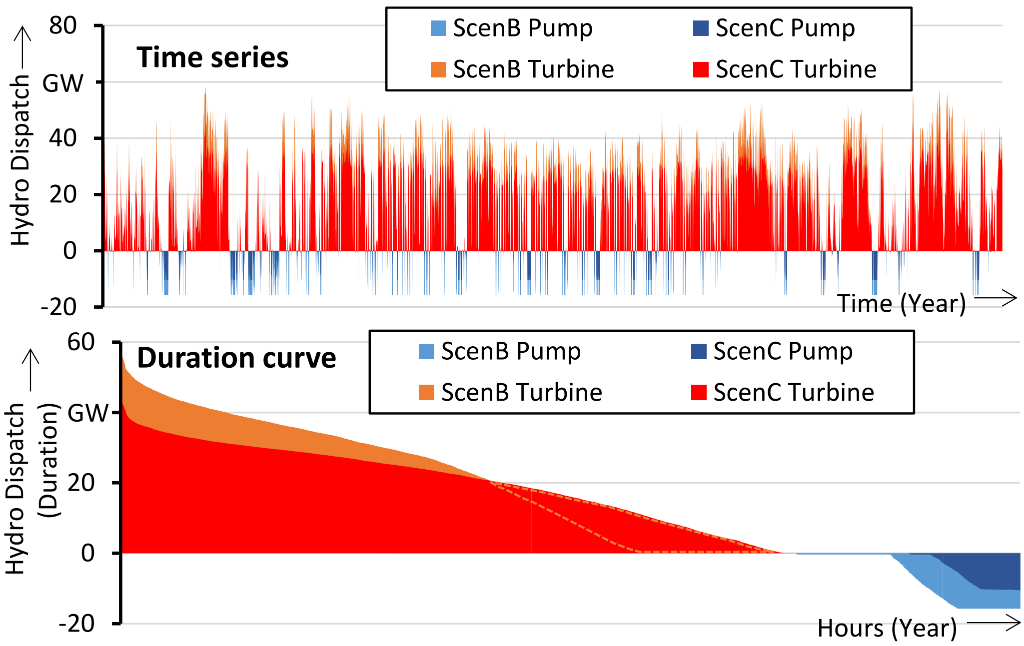

Figure 5.10: **Dispatch of hydropower in Norway**

The reason for this is the higher transfer capacity from Norway to the mainland as well as higher transfer capacities between other market areas. The hydropower dispatch in Norway is highly influenced by RES generation in Europe and by existing transfer capacities. Additional simulations with lower share of RES (58% in Europe) and less transfer capacity between Norway and the continent show that in this case the high turbine capacity is never fully utilized and the pumps were only dispatched in a few hours per year (see Figure A.3 in the Appendix).

When enough transfer capacity is available, the Norwegian hydropower is utilized to balance intermittent feed-in in Europe as can be seen in Figure 5.11 for scenario B. Therefore, the high transfer capacities enable the installed turbine capacity (59.7 GW) to be fully utilized in some situations with very low RES feed-in in the rest of Europe. Due to the flexibility from the combination of large hydro storages, large generation capacity and high natural inflows, the pumps are utilized in less than 1,200 hours per year.

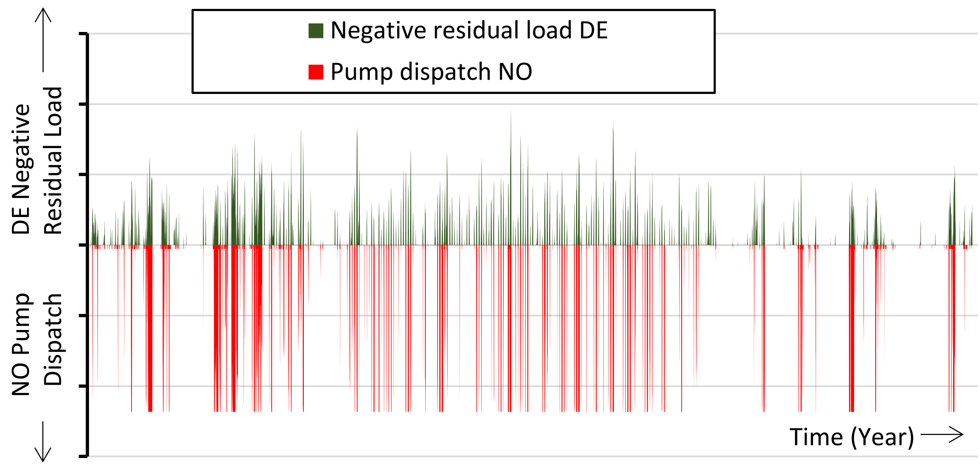

Figure 5.11: **Correlation of Residual Load in Germany and Norwegian Pump Dispatch (scenario B)**

The resulting storages levels of all aggregated storages and all aggregated pumped storages in Norway is shown in Figure 5.12. While the level of the large storages is changing only in a rather small range, the storages with pumping capacity nearly utilize the full storage capacity.

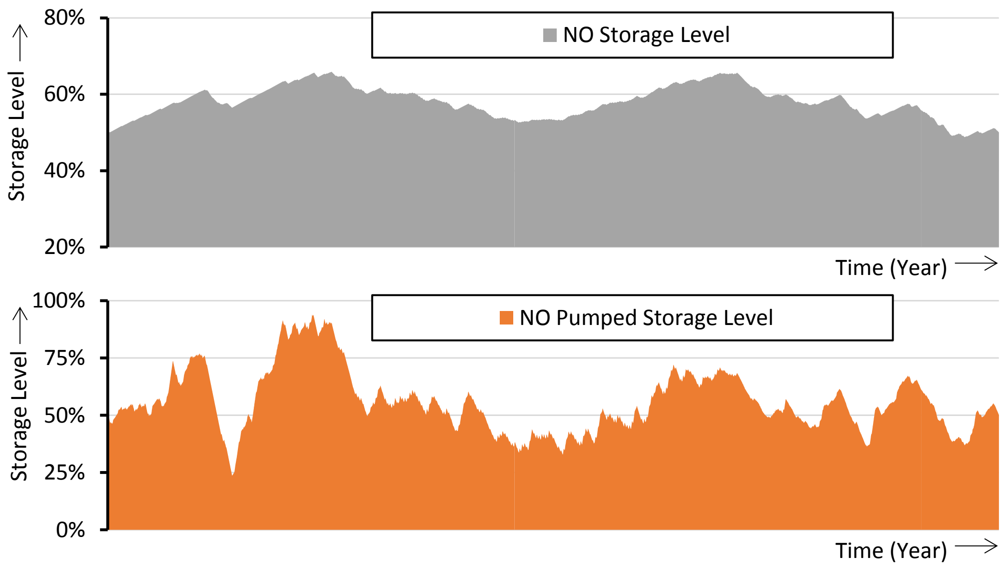

Figure 5.12: **Dispatch of Storages and Pumped Storages in Norway in Scenario B**

5.2.2 Spot and Reserve Prices

Two price series for the spot market can be derived from the simulations. While the first price series comes from the European market simulation for all European countries with an hourly resolution, the second series is derived from the detailed German simulation with a ¼-hourly granularity. Figure 5.13 depicts the two price series for Germany in both scenarios.

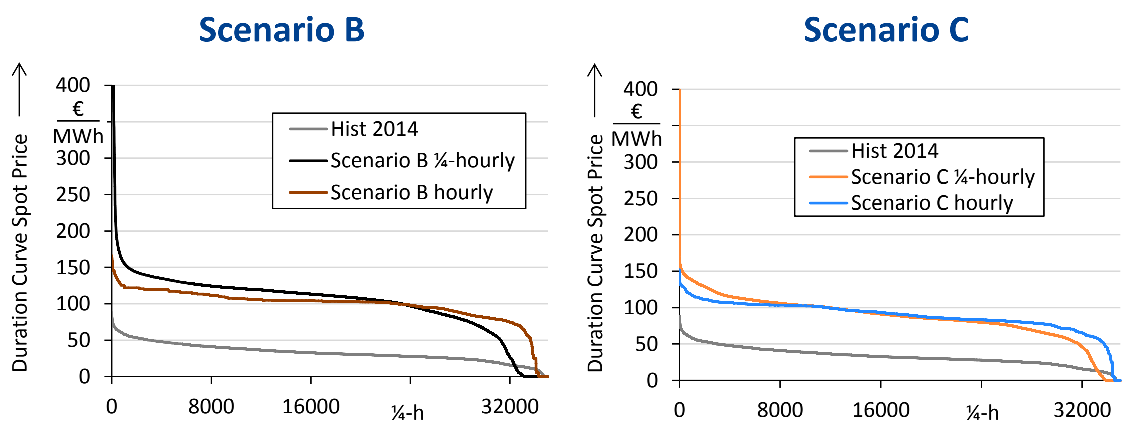

Figure 5.13: Duration curves of simulated spot prices for Germany (weather year 2008)

The price levels of the hourly and ¼-hourly prices are similar but the structure of the duration curves slightly differ. In the ¼-hourly prices, there are more high prices but also more low prices. The reason is a higher price volatility in the detailed German market simulation due to the consideration of inter-hourly gradients of the residual load as well as detailed reserve provision. In comparison with scenario C, the prices in scenario B are slightly higher which is due to the difference in the generation stack in both scenarios. In scenario C, there are less hydropower (except for Norway) and nuclear power plants, which have low marginal costs and, thus, lower spot market prices for electricity. The increase of prices in relation to 2014 prices results from the rise of (variable) conventional generation costs, which are mainly determined by fuel and CO_2 certificate prices.

In addition to the spot market prices, the detailed German market simulation also provides prices for reserve power and reserve energy. The reserve power prices for both scenarios are displayed in Figure 5.14. In the diagrams, the dark blue line represents the average price while the top of each bar is the average of the 3,120 highest prices and the bottom the average of the 5,640 lowest prices. This reflects the size for the peak and off-peak products of the current trading scheme with the difference that they are not depending on the time of day but only on sorted prices.

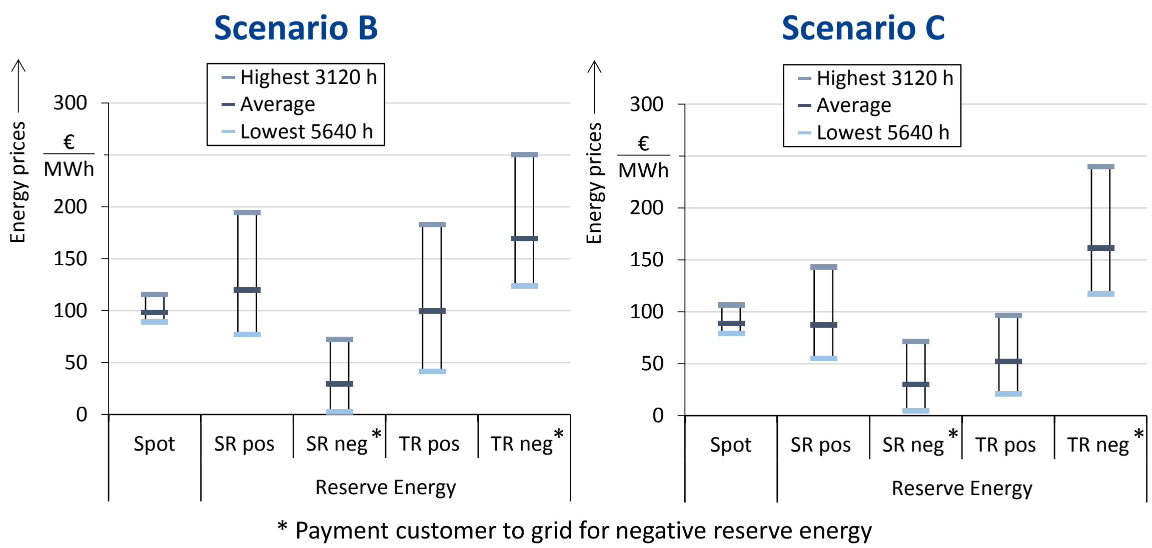

Figure 5.14: Simulated reserve energy prices for Germany (weather year 2008)

The reserve energy prices reflect the marginal costs for reserve activation. Since power plants that are more expensive often provide TR energy, the prices for TR energy are higher than for SR. It should be noted that the prices for negative reserve products are defined as a payment from the customer to the TSO. Furthermore, the reserve energy prices always have to be interpreted in connection with the reserve power prices and the spot market prices. An overview of the simulated reserve power prices is given in Figure 5.15.

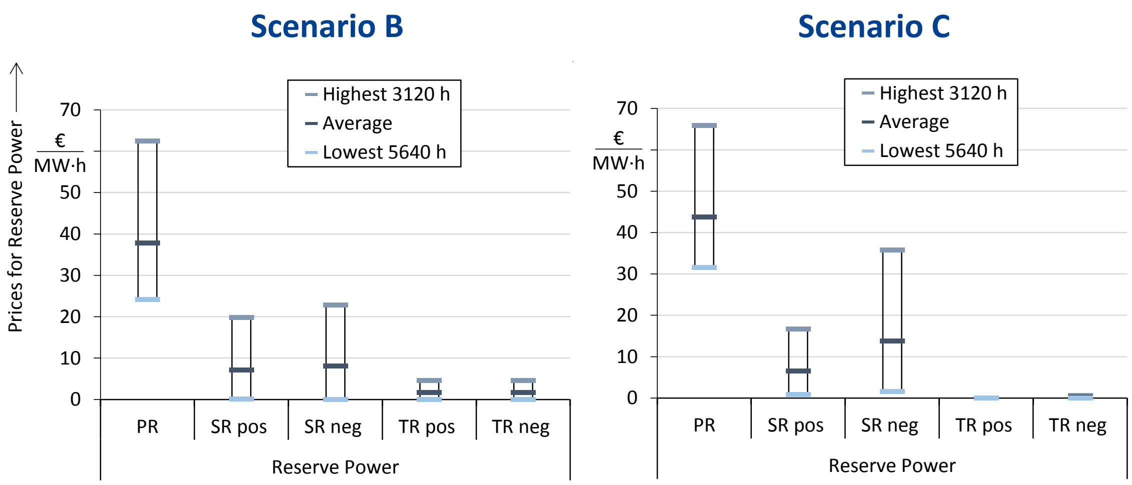

Figure 5.15: Simulated reserve power prices for Germany (weather year 2008)

Since PR is the reserve quality with the strictest requirements regarding flexibility and, additionally, is only remunerated by power prices, the prices for PR power are higher than for the other reserve qualities. TR is mostly provided by OCGT (from standstill) or by RES. That is why the price for TR power provision in scenario C is close to zero. In scenario B, the reduction of OCGT capacity leads to a slight increase in TR power prices. The higher prices for SR power in scenario C can be explained by the spot market prices. Since these are higher in that scenario, more power plants are in operation in average and thus can provide negative reserve power more cost-efficient.

5.2.3 Spot Prices for Different Weather Years

This study also investigated the effect of different underlying weather years concerning wind and solar feed-in as well as hydropower inflows on the spot price results. In addition to the year 2008, which was used for the base simulations, the weather years for 2007-2009 and 2010-2011 were used as input data for the simulations. The installed capacity of RES and conventional power plants remains unchanged to the base simulations. Since inflow data provided by SINTEF are only available for Norway, these data were adapted for Sweden but kept constant for the other countries. Data on solar radiation and wind speed are available from Eurowind for all regarded countries. Figure 5.16 gives an exemplary overview of the effect of different weather years on the wind and solar feed-in for Germany as well as on the average hydropower inflow for Norway and Sweden.

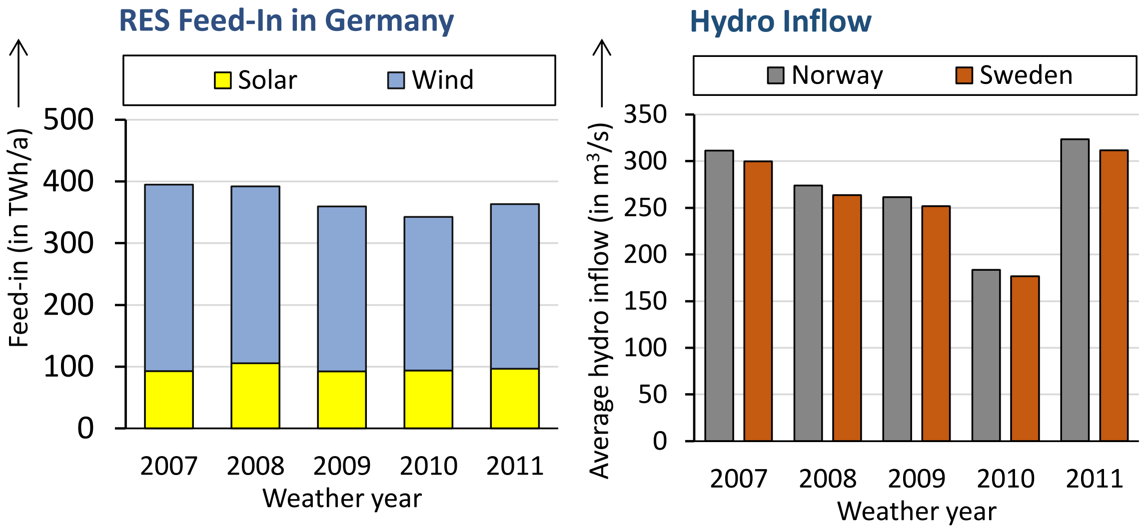

Figure 5.16: RES Generation and hydro inflow in different weather years

By taking the feed-in for the weather year 2008 as a reference, the variation of wind power feed-in remains in the range between 87% and 105%. For PV feed-in the range is between 89% and 100%. For hydropower feed-in the bandwidth is considerably higher in a range between 67% and 118%. These differences in RES feed-in have an impact on the spot market prices as shown in Figure 5.17 for Germany and Norway in scenario B.

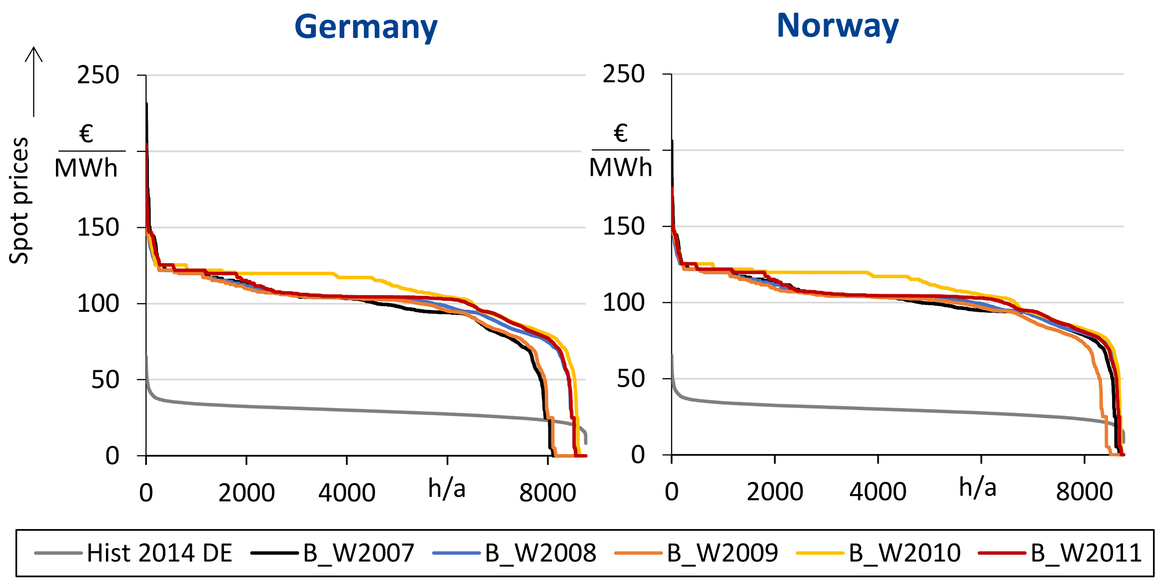

Figure 5.17: Duration curves of spot prices in different weather years - scenario B

The curves show a comparable course for both countries in the different weather years due to the high transfer capacity and the resulting spot price convergence. However, there are also some differences, especially in the area with low prices in the duration curves. It can be seen that the weather years 2007 and 2009 cause significantly more prices close to zero. This is due to more extreme wind situations in these years with high wind power feed-in and, thus, more situations with surplus power generation. Another obvious difference is the price increase in simulations with the weather year 2010. This increase is a result from the low RES and hydropower feed-in in the simulation using weather year 2010.

Figure 5.18 displays the price duration curves for different weather years in scenario C.

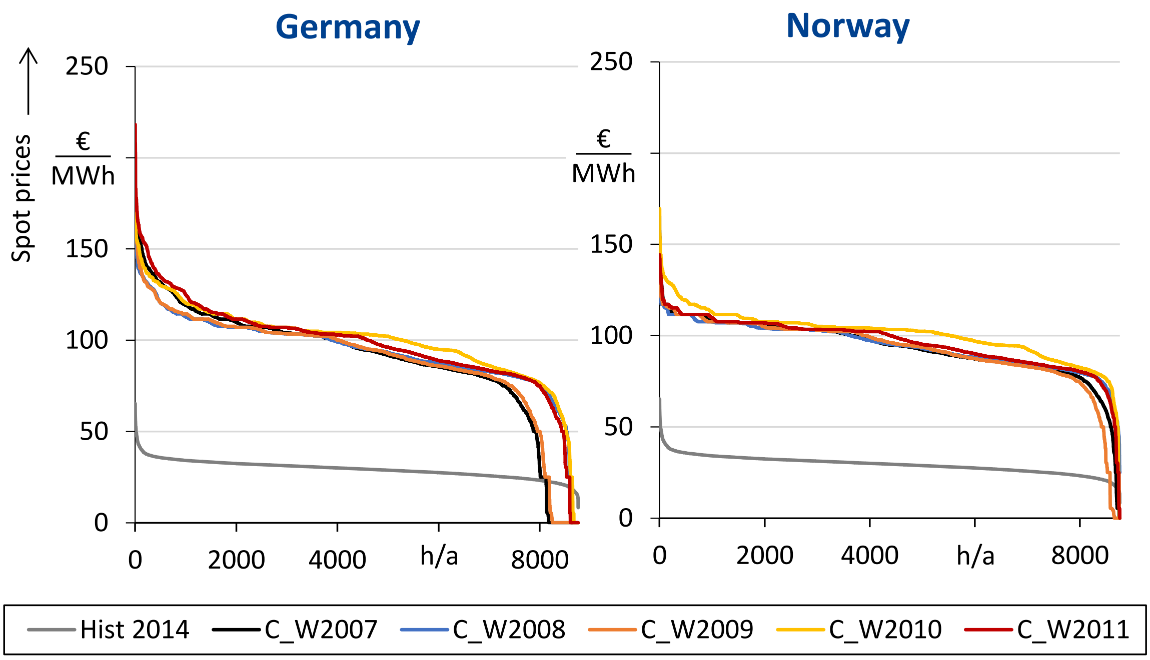

Figure 5.18: Duration curves of spot prices in different weather years - scenario C

The effects from using different weather years for scenario C are similar to scenario B. One difference is that the prices with weather year 2010 show a lower increase. This comes from a higher installed capacity of thermal and hydropower plants in scenario C (except for Norway) and thus the impact from RES feed-in and hydropower generation in Scandinavia is slightly more leveled out.

Additional information about the price effect from different weather years can be gained from the price indicators shown in Figure 5.19. The general course of the price indicators is similar for both countries and both scenarios. The increased spread between the highest and lowest prices in scenario C can be explained by the grid assumptions. In scenario B, the exchange capacities are higher and thus the European markets are coupled stronger. This coupling enables a better smoothening of intermittent RES feed-in which reduces price volatility.

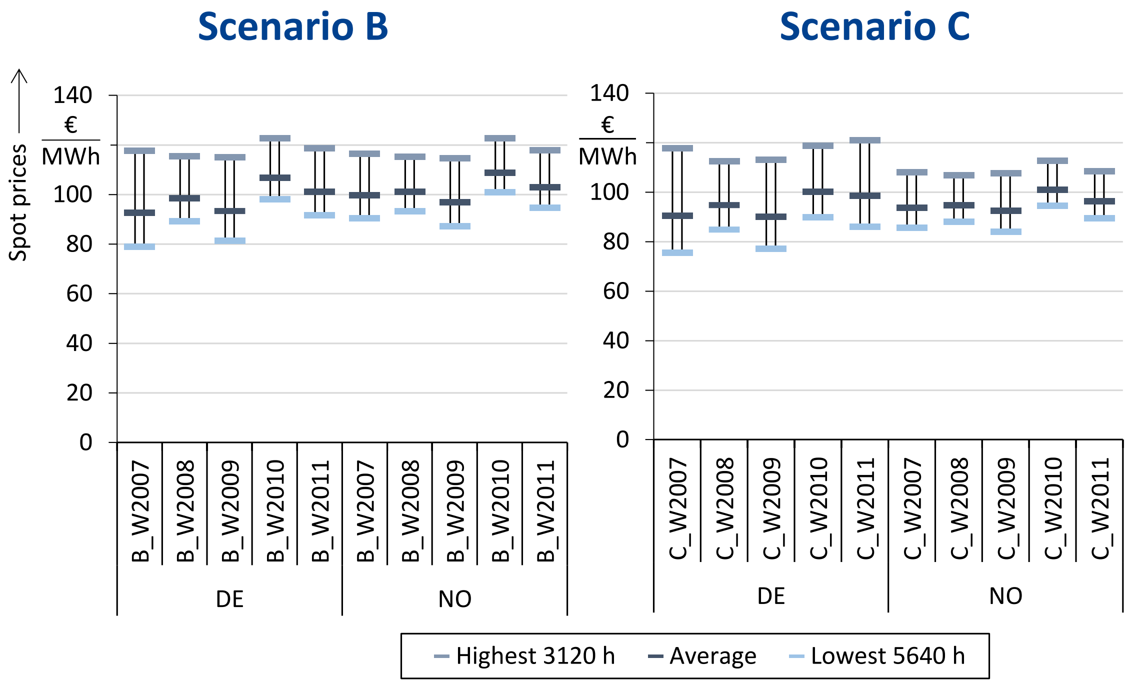

Figure 5.19: Price indicators in different weather years

5.3 Macroeconomic Results – Sensitivities

In addition to the base cases for both scenarios, also a sensitivity regarding the utilization of transfer capacities (see Chapter 2) is simulated. Whether the transfer capacities are optimized only for scheduled energy (no Reserve Exchange) or also for reserve exchange assuming cross-border balancing markets (Reserve exchange) influences the total variable system costs. These costs for both scenario are displayed in Figure 5.20.

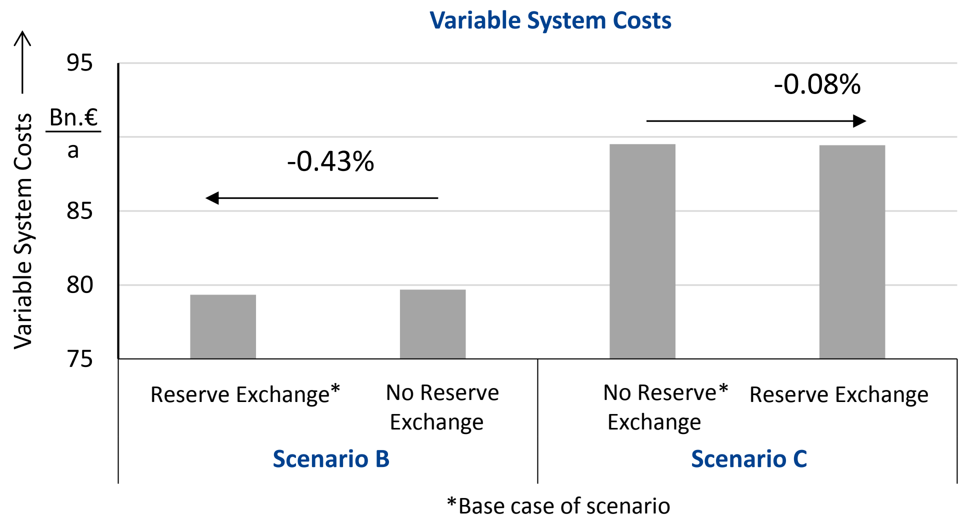

Figure 5.20: Impact of reserve exchange scheme on variable system costs

Optimizing the utilization of transfer capacities for scheduled energy and reserve decreases the total variable system costs. This difference amounts to 345 mil. €/a (0.43%/a) in scenario B and 70 mil. €/a (0.08%/a) in scenario C. The main reason that the benefit from reserve exchange in scenario B is higher than in scenario C is the generation stack. In scenario B, the capacity of conventional hydropower generation is decreased. Especially the reduced hydropower capacity increases the value of flexibility in this scenario. Furthermore, the additional transfer capacity in scenario B provides more potential for reserve exchange.

5.4 Microeconomic Results

The price results obtained from the detailed simulation of the German markets for electrical energy and reserve are the basis of the microeconomic evaluations. This chapter first describes the market potential of the RES portfolio (see Chapter 4.2) with and without access to the Norwegian pumped storage power plant. Subchapter 5.4.2 then gives an overview of similar investigations regarding the mixed portfolio. In the last part of this chapter, the additional impact of prognosis errors from wind and solar power on the benefit of additional storage in the RES portfolio is evaluated. For that, the dispatch of the RES portfolio is consecutively performed for the different trading steps of the historic market environment of 2014 as described in subchapter 3.4.

5.4.1 RES Portfolio

The considered portfolio consists of wind and solar power combined with a smaller share of flexible generation from biomass. Figure 5.21 shows the portfolio dispatch on the left regarding generation compared to the spot prices and on the right the reserve dispatch for an exemplary week.

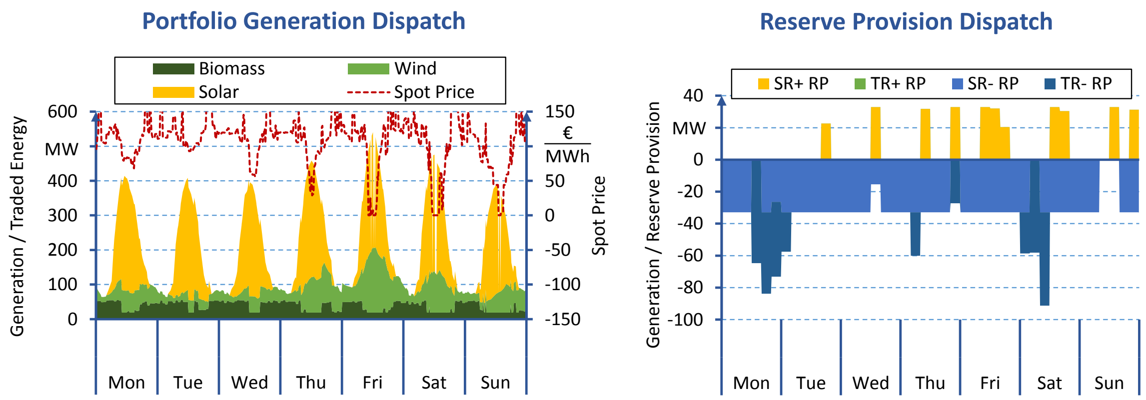

Figure 5.21: RES portfolio – exemplary stand-alone dispatch (calendar week 18 – scenario B)

The feed-in of wind and solar power is intermittent with no variable costs so that only during hours with prices of zero (Friday, Saturday and Sunday mid-day) the solar feed-in is subject to curtailment. Curtailment of wind power does not occur since wind power generation units are providing reserve for downward regulation in low-price situations. The biomass unit also has very low generation costs but has a limited energy supply. Therefore, the dispatch is mainly driven by the spot prices. The RES feed-in of the portfolio is consistent to the market area wide feed-in used in the market simulation. This leads to a negative correlation of spot prices and RES feed-in.

Since the biomass unit is able to provide the more expensive SR in negative direction without significant changes in its dispatch the full reserve potential is marketed in most time intervals. On Saturday mid-day the provision of negative reserve even leads to a dispatch of the biomass plant at a spot price of 0 €/MWh. Positive SR on the other hand is only provided during intervals with low spot prices. Whilst positive TR is not provided by the portfolio, negative TR is provided by wind power plants in some situations.

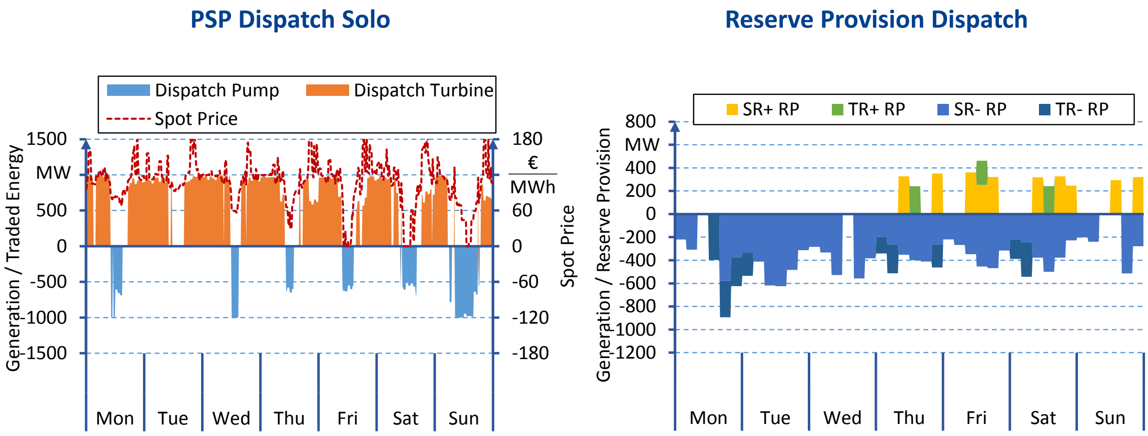

Figure 5.22: Norwegian PSP – exemplary stand-alone dispatch (calendar week 18 – scenario B)

Figure 5.22 shows the dispatch of the pumped storage marketed solo. The dispatch of the storage is correlated to the spot prices. When the price is low, the pump is dispatched to store energy. During high prices, the turbine is used to generate and sell power. The turbine generates more power than the amount which is stored by the pump since an inflow into the basin is considered in the simulation.

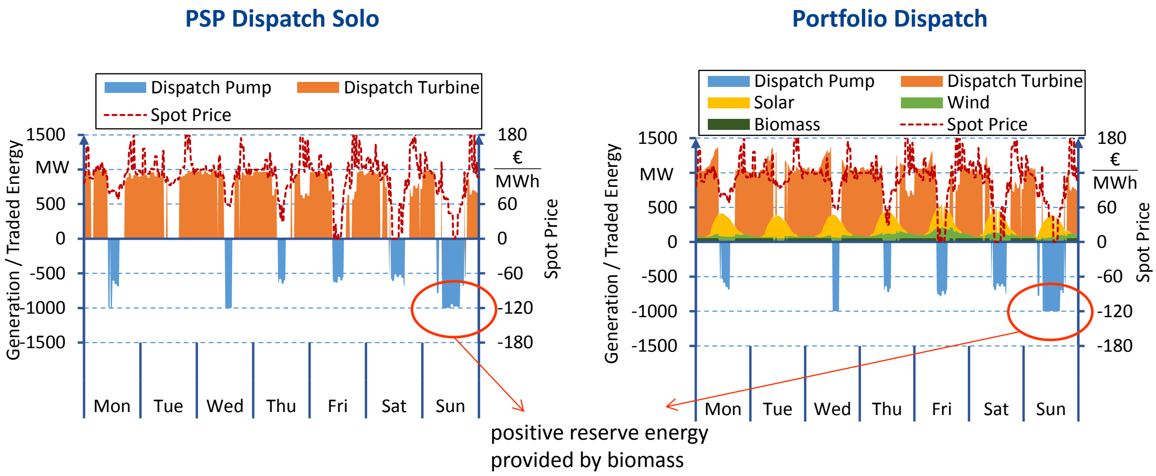

Figure 5.23: RES portfolio with PSP – exemplary dispatch (calendar week 18 – scenario B)

The storage dispatch when marketed solo and the dispatch in the portfolio is rather similar with small differences in the provision of reserve power and energy. During times of pumping the activation of positive reserve is provided by the pump when marketed solo. When marketed in the portfolio, the activation of positive reserve results in an increased dispatch of the biomass power plant.

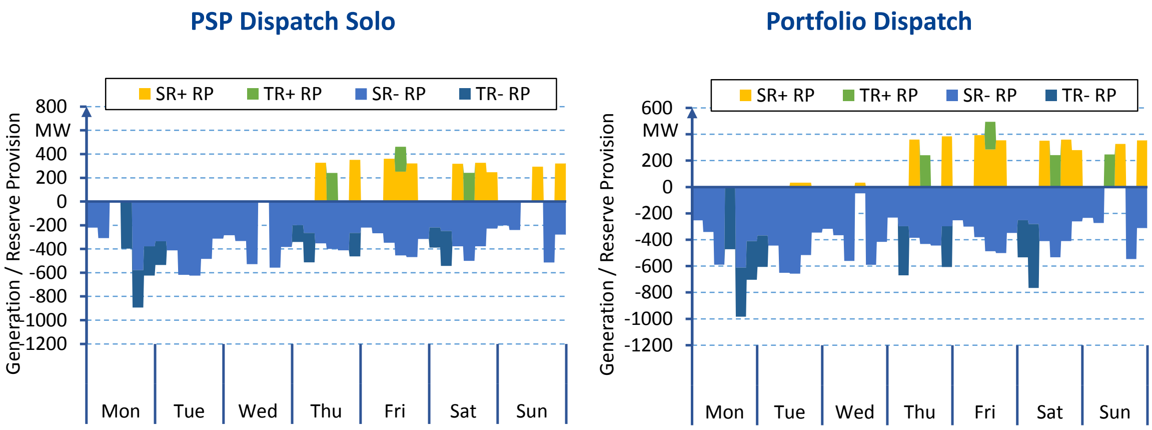

Figure 5.24: Norwegian PSP – exemplary dispatch (calendar week 18 – scenario B)

Figure 5.24 compares the reserve provision of the PSP solo and included into the RES portfolio. The reserve provision of the portfolio is dominated by the PSP. The distribution on the different reserve qualities is similar to the separate optimization. Although in some time intervals, additional reserve is provided by the portfolio that was not suited for separate provision. One example is the provision of positive TR on Sunday mid-day or negative reserve on Monday mid-day. These differences are rather minor but may lead to a small increase in the obtained contribution margins.

The overall contribution margin from the simulated year is shown in Figure 5.25 for different RES portfolio combinations and the two scenarios.

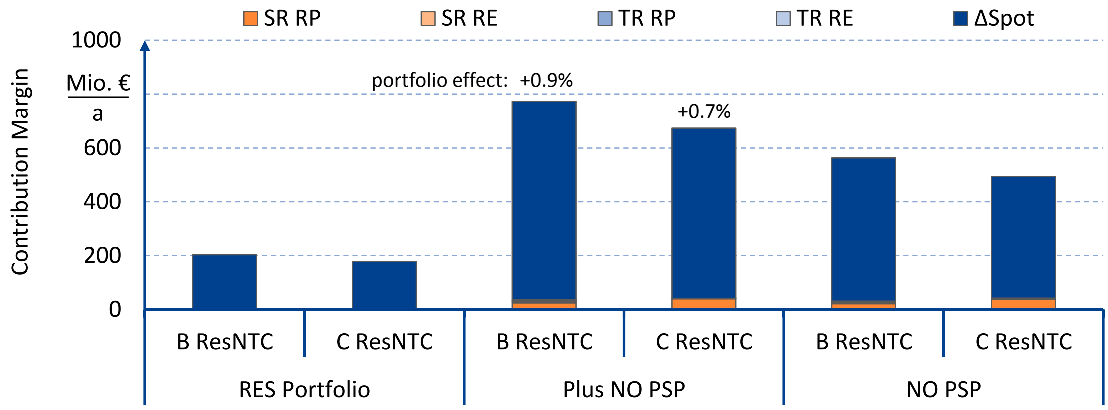

Figure 5.25: RES Portfolio - contribution margin and portfolio effect

The blue bar shows the contribution margin from the spot market as delta between revenues from trading generated energy and costs for pump energy and primary energy. All portfolio combinations gain the highest share of their contribution margin at the spot market. This can be explained by the absence of variable generation costs for RES and the relatively high basin inflows of the storage plant. The difference between the sum of the contribution margins when marketed separately to the combined marketing yields the portfolio effect. This effect mainly results from reserve marketing. A combined reserve marketing enables optimizing the distribution of reserve power and reserve energy provision on the different generation units in the portfolio. This impact especially occurs when reserve products cover several time steps. In this study, a commissioning time for reserve products of four hours is assumed (see Chapter 2). In comparison to +0.9% in scenario B, the portfolio effect in scenario C with +0.7% is slightly lower. The higher contribution margins in scenario B, resulting from higher spot prices (see Figure 5.19), also generate a higher portfolio effect and thus a higher benefit of marketing the Norwegian PSP combined with the RES portfolio.

In order to compare the contribution margin generated at the reserve market, Figure 5.26 shows the corresponding contribution margin without the spot market revenues and costs.

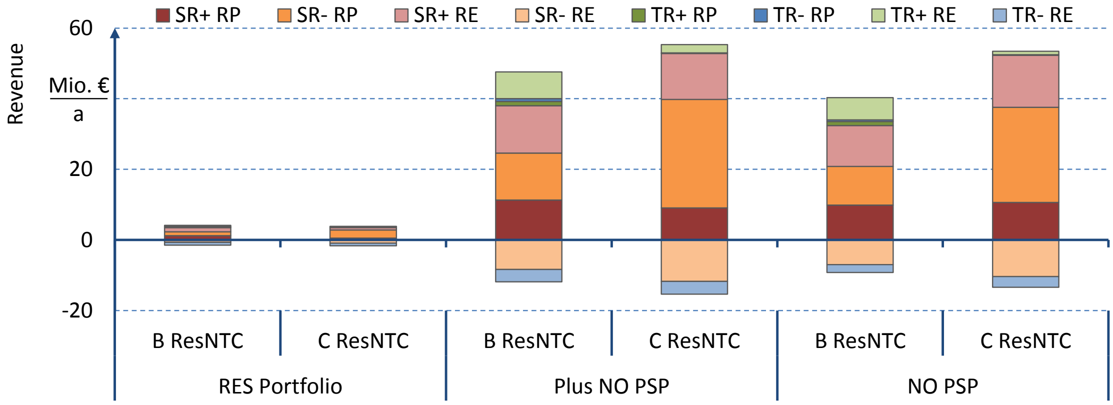

Figure 5.26: RES Portfolio - revenues at reserve markets

The revenue of the PSP at the reserve markets are by far higher than the RES portfolio's revenue. This mainly results from providing SR power and energy. In scenario B, additional revenues from providing positive TR can be generated due to higher prices on this market (see subchapter 5.2.2). When marketed in combination with the RES portfolio the increase in revenue mainly results from negative SR and positive TR that can be provided more efficiently in the combined portfolio.

Even though wind generation units have the flexibility to provide reserve power, they cannot guarantee to be available for the full product time at the time of the reserve auction. In a portfolio, on the other hand wind power plants can be used in the portfolio dispatch optimization to take part in the reserve provision whenever there is enough wind available. The results shown above assume that the overall market share on all reserve markets stays the same when the portfolio is marketed in combination with the PSP reflecting the above mentioned. On the other hand, it could also be assumed, that the combined provision allows the wind power plants to also contribute to the amount of reserve power that can be bid in the reserve auction when the PSP is available as a back-up in case of insufficient wind speed. This would result in additional marketable reserve power for the portfolio and possibly a higher market share. In order to assess this effect, additional investigations are performed increasing the SR market share of the combined portfolio by 10% of the wind power generation capacity. Since the higher share cannot be quantified fundamentally, this is only an estimation of one possible outcome. The result is to be interpreted as an indication on how this could affect the portfolio contribution margin. Figure 5.27 compares the resulting contribution margin with the results shown so far assuming a steady market share where the maximum marketable reserve power stays unaffected by the portfolio composition.

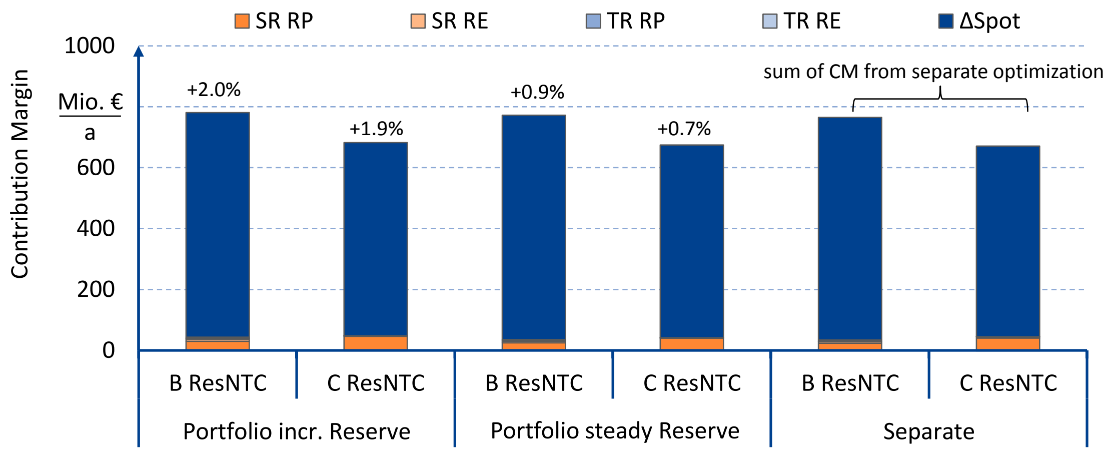

Figure 5.27: RES Portfolio – impact increased reserve market share portfolio effect

Because of the optimized reserve provision in combination with the additional reserve, marketing options the portfolio effect increases to 1.9% and 2.0% for the two scenarios. Hence, with an increasing share of reserve marketing of the total contribution margin also the additional benefit from having access to a Norwegian PSP rises.

5.4.2 Mixed Portfolio

The mixed portfolio has a smaller share of RES generation in combination with CCGT and OCGT power plants (see Chapter 4.2). Figure 5.28 shows the resulting dispatch optimized against market prices for electrical energy and reserve provision. Whilst the dispatch optimization is performed for an entire year and both scenarios, the figure only shows the results for one exemplary week in scenario B.

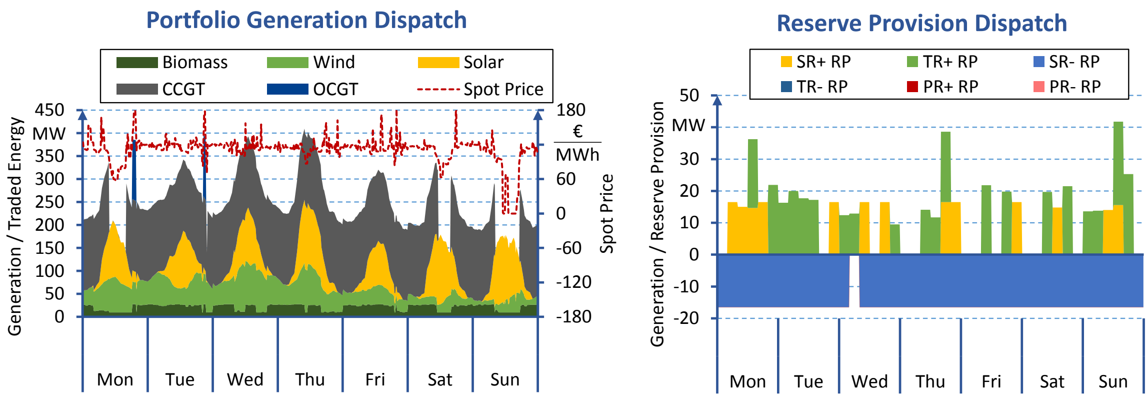

Figure 5.28: Mixed portfolio – exemplary dispatch (calendar week 22 – scenario B)

The dispatch of the RES power plants (depicted in yellow and green on the left) is equivalent to the results of the RES portfolio. The CCGT power plant only shuts down during periods of low spot prices. The OCGT has higher variable costs and therefore is only in operation in times with high spot prices. During standstill, the OCGT also provides positive TR in some hours. PR is only provided in few situations since the market share of gas-fired units is very low at the market for PR.

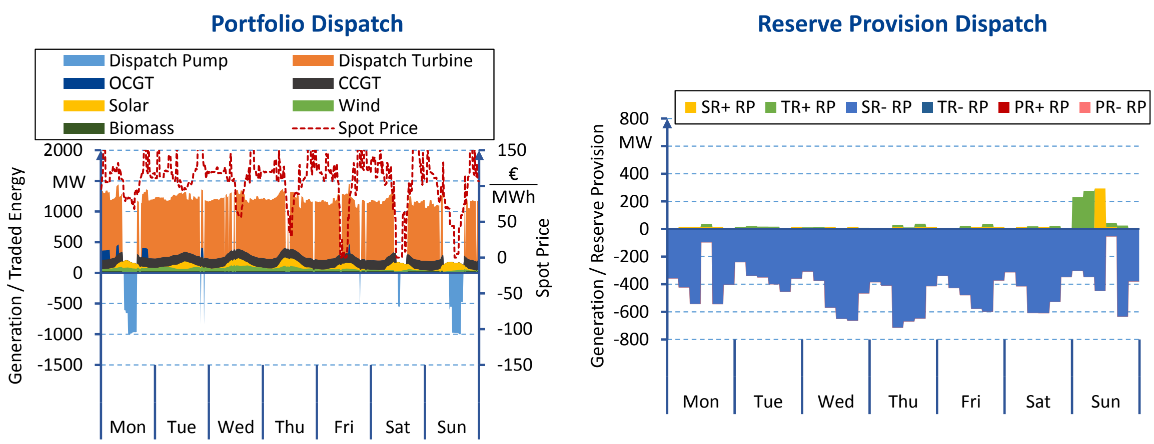

Figure 5.29: Mixed portfolio with Norwegian PSP – exemplary dispatch (calendar week 22 – scenario B)

The combined dispatch of the mixed portfolio with the Norwegian PSP is shown for the exemplary week in Figure 5.29. The combined optimization has a smoothening effect on the dispatch of the thermal power plants. This is mainly a result of the optimized allocation of reserve provision and reserve energy. The sum of reserve provision of solo dispatch is similar to the combined results with the difference that being able to distribute the reserve provision freely enables to market slightly more reserve power in the combined portfolio. The resulting contribution margin for both scenarios is shown in Figure 5.30. The portfolio effect for the mixed portfolio yields to +0.4% for scenario B and +0.2% for scenario C. An increase of the portfolios reserve market share by 10% results in a portfolio effect of up to +1.0%. In comparison with the RES portfolio, the portfolio effect is reduced. This shows that the added value of additional flexibility from PSP is higher for portfolios with low inherent flexibility, especially portfolios mainly consisting of wind and solar power plants.

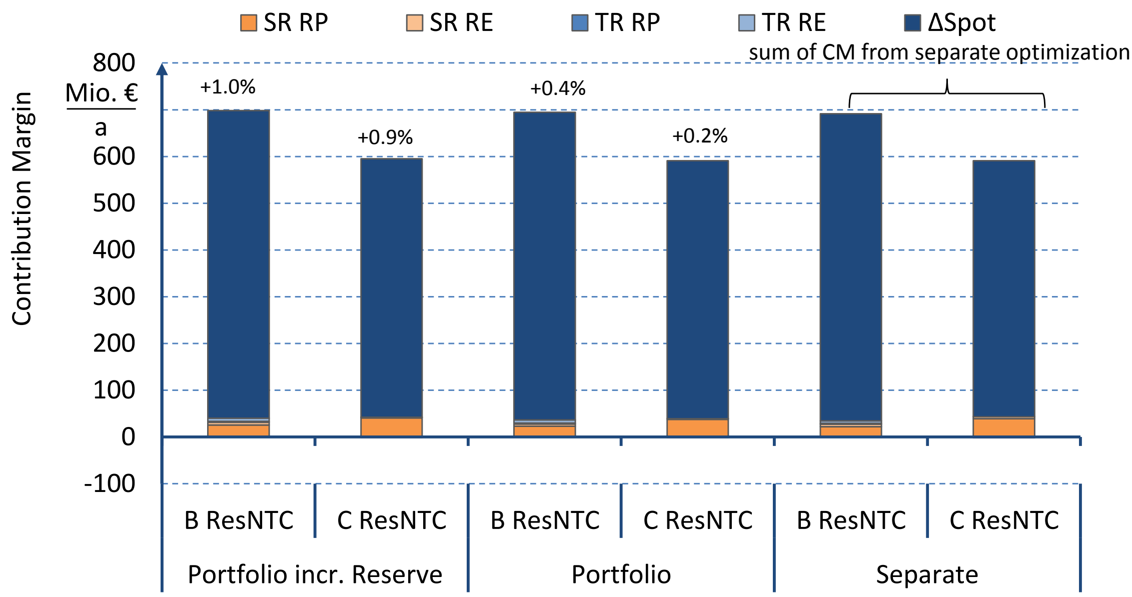

Figure 5.30: Mixed Portfolio – impact of increased reserve market share on portfolio effect

In order to identify the scenario in which it is more beneficial for a portfolio in Germany of having access to a Norwegian PSP, Figure 5.31 shows the contribution margin with and without the Norwegian PSP in the portfolio. It should be noted that in the base case the PSP does not participate in the German but in the Norwegian market. This way the available transfer capacity is not reserved and is modelled as an additional degree of freedom to the optimization.

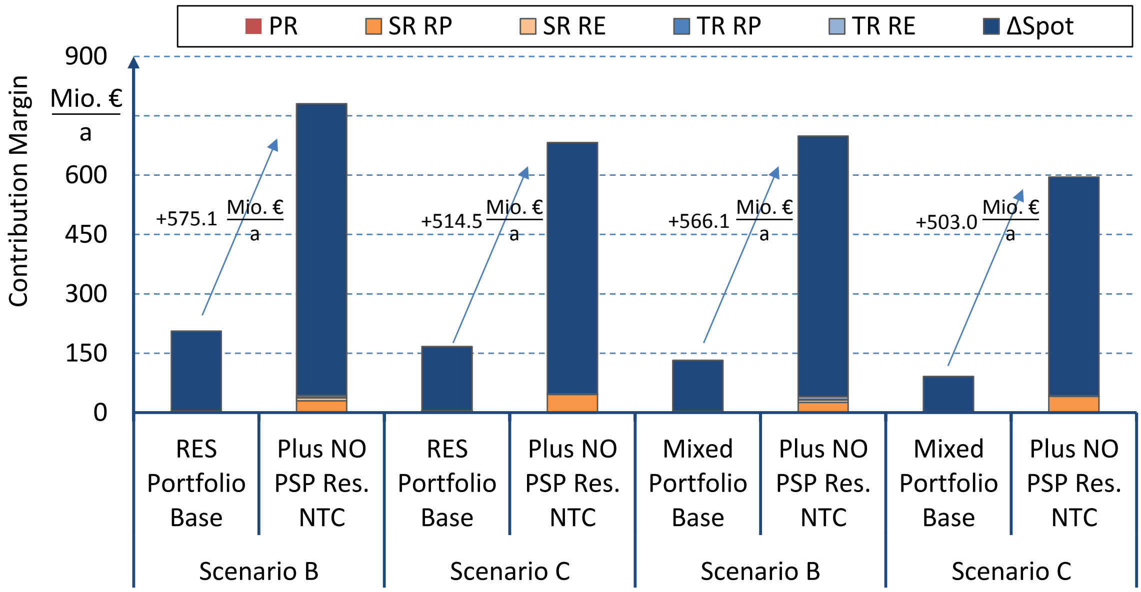

Figure 5.31: Additional contribution margin from Norwegian PSP

When comparing the different portfolios, the additional contribution margin of the RES portfolio appears to be higher than for the mixed portfolio. Furthermore, the benefit in scenario B exceeds the additional value in scenario C. The reason for both effects is the value of flexibility, which is always higher in an environment with low inherent flexibility. The RES portfolio mainly consist of non-dispatchable wind and solar power plants. Thus, PSP can add significant value to the portfolio. Regarding the scenarios, scenario B has reduced thermal and especially hydropower capacity in Europe except for Norway. Hence, in this scenario again the benefit from additional flexibility is higher.

An analysis of the situations in which a portfolio effect can be gained for the RES portfolio in scenario B is shown in Figure 5.32. The blue line represents a duration curve of the residual load and the grey line the corresponding portfolio effect gained in the respective hour. Since reserve products are defined for more than one hour, the portfolio effect can turn out negative in certain hours. The diagram shows that most of the positive portfolio effect comes from situations with a medium-range residual load. In situations with very high or very low residual load the benefit from the mutual optimization in a portfolio is lower. In these situations, extreme prices often occur und thus the dispatch decision is very distinct. For example, in hours with a significant negative residual load the spot market prices are going to be close to zero resulting in the dispatch decision for conventional power plants not to be in operation and for PSP to operate the pumps. A mutual optimization of different power plants will lead to the same resulting dispatch. As a matter of course, a benefit of optimization in a portfolio can still occur in situations with extreme residual loads when considering reserve marketing.

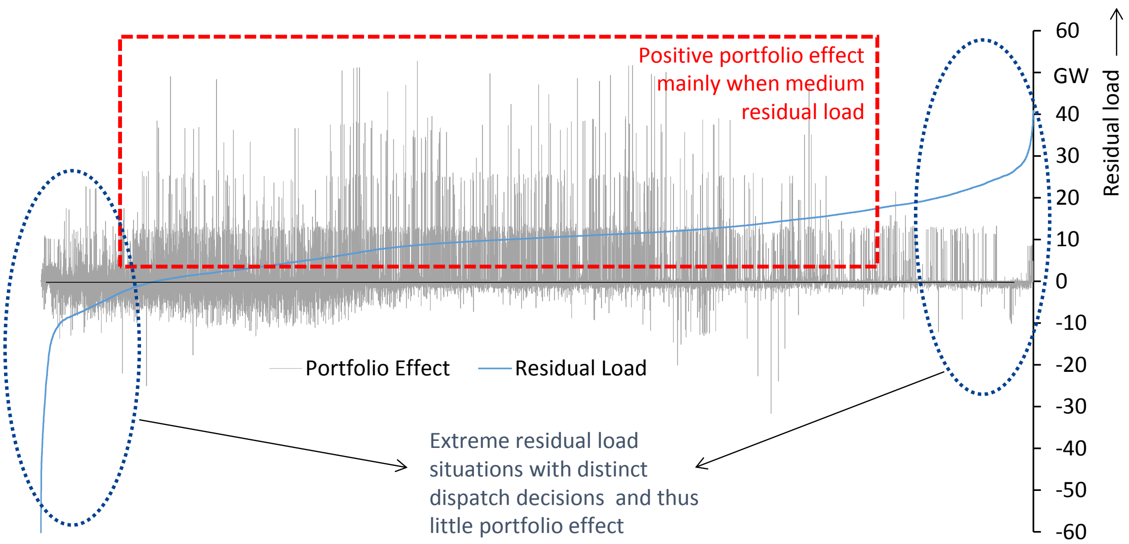

Figure 5.32: Correlation of portfolio effect and residual load (scenario B; RES portfolio)

5.4.3 Impact of Prognosis Errors

Besides the efficient distribution of reserve provision inside the portfolio, the Norwegian hydro storage can also be dispatched to balance the prognosis errors of RES feed-in. This can limit the risk of balancing group deviation and reduce the costs for balancing energy. In case of surplus generation from the RES power plants, the stored energy can also be sold at the intraday market.

In order to evaluate this benefit to an exemplary RES portfolio, the 3-step approach explained in Chapter 3.4 is being applied to the RES portfolio. Since it is crucial for assessing the benefit that the prices in all three steps (day-ahead prices, intraday prices and prices for balancing energy) fit to forecast deviation values of the RES feed-in, these simulations are not performed for the simulated price set from Chapter 5.2.2. Instead, the historic prices for Germany from EPEX Spot between March 2013 and February 2014 are used in combination with the corresponding actual feed-in forecasts and measured values of exemplary wind and solar generation portfolios. The needed balancing energy is remunerated with the price for balancing energy (ReBap) of the respective time interval. That way, a realistic market situation that matches the forecast deviation provides the basis of the simulations.

The simulations are performed for the RES portfolio and the Norwegian PSP marketed separately and marketed as a combined portfolio. The resulting contribution margin of each market step is depicted in Figure 5.33. The green and yellow bars on the left reflect the contribution margins of the portfolios marketed separately, the blue bar when marketed as one portfolio.

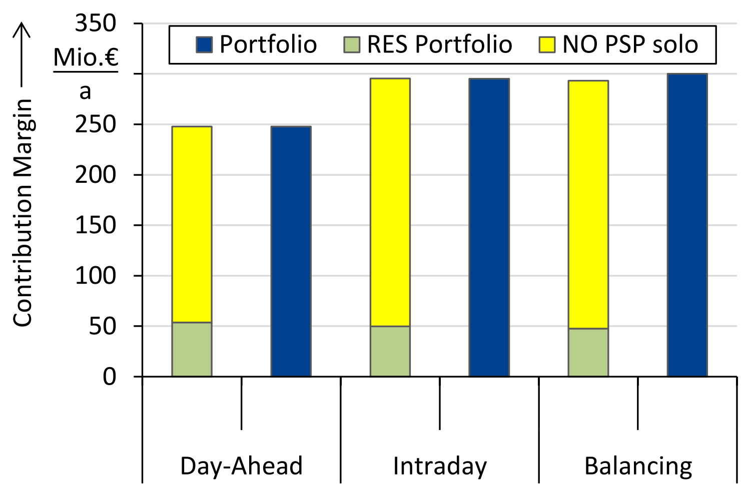

Figure 5.33: Comparison of portfolio contribution margin in different market steps

In comparison to the day-ahead step, the NO PSP is able to increase its contribution margin at the intraday market equally when marketed separately or in combination with the RES portfolio. This is a result of the higher intraday price volatility and the possibility to benefit from day-ahead to intraday counter trades when the market situation is favorable. For the RES portfolio, there is a slight decrease in contribution margin from day-ahead to intraday. This is a result of the need to trade the prognosis deviation at the intraday market even if prices are not favorable. The biggest difference results from the balancing market step. When marketed solo, the RES portfolio's only option for balancing is the biomass plant. Since this share is rather small in comparison to the full portfolio, most deviations have to be balanced using balancing power. In the current market situation in Germany, the deviation can also results in revenue for the portfolio. This is the case if the deviation of the portfolio is beneficial for the total system (i.e. deviation is in contrary to the system wide deviation). However, in total this results in costs of 2.74 mil. €/a for the RES portfolio. The energy stored by the biomass unit results in additional revenues of 0.5 mil. €/a. Figure 5.34 shows the resulting costs and revenues from balancing.

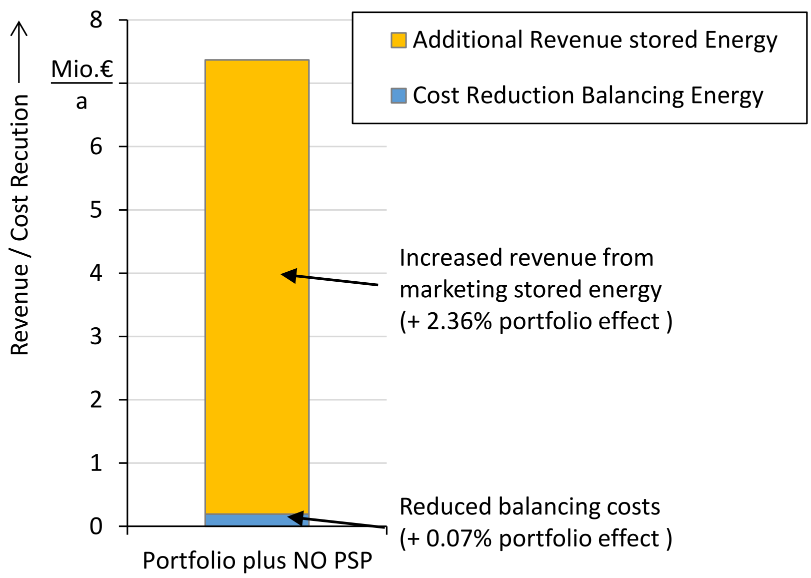

Figure 5.34: Portfolio effect from marketing stored energy and reduced balancing energy from prognosis errors

When marketed in combination with the Norwegian PSP, the necessary balancing energy can be reduced considerably. The effect on the costs for balancing energy is only marginally affected since both, revenues and costs from balancing energy are reduced. Since the actual price is subject to uncertainty, the risk of high balancing costs is reduced this way. By storing energy from surplus generation in the balancing group that can be sold on the market later additional revenues of 7.55 mil. €/a can be generated.

Both, reduced costs for balancing energy and additional revenues from stored energy lead to a portfolio effect of +0.07% from reduced balancing costs and considerable +2.36% selling the stored energy.

6 Summary and Conclusions

The expansion of RES in Europe triggers the need for flexibility in the power system. Norwegian hydropower plants have the potential of a possible contribution to the provision of flexibility. Having access to these highly flexible power plants can create an additional value, e.g. for companies engaged in the German power market such as utilities and TSO. Utilities can use hydropower plants in their portfolio to optimize the participation in the markets for scheduled energy and reserve. TSO might have a potential for cost reduction from transnational reserve exchange, which might lead to a decrease in total costs for reserve provision.

The target of this study was to analyse the benefit for German utilities and TSO from having access to Norwegian hydropower. To do so, European market simulations for two different scenarios for the year 2050 were performed with and without reserve exchange to determine hourly power generation, power exchanges and spot market prices. Both scenarios include an expansion of hydropower capacity in Norway up to 60 GW. In scenario B, the necessary flexibility is largely provided by hydropower from Norway while in scenario C the flexibility within the European countries is higher in general. In order to assess the overall benefit of additional hydropower in Norway to the European power system, the simulation results were compared to a simulation without the increased capacity.

In a more detailed simulation of the German market area, ¼-hourly spot and reserve market prices were derived. Based on the simulated prices, portfolio optimizations were performed for an RES and a mixed generation portfolio in the German market with and without access to a Norwegian hydropower plant.

Preliminary investigations showed that linking of the Norwegian or also Scandinavian power system with the rest of Europe requires a massive expansion of cable transfer capacity if frequent congestions are to be avoided. The necessary transfer capacity across the North Sea towards UK, Netherlands, Germany and Denmark amounts up to nearly 30 GW in the regarded scenarios. With the grid expansion and thus the strong market linking, the spot market prices in Norway showed a similar course to Germany and Central Europe in general. The prices are mainly influenced by fuel costs and the RES feed-in. Under the assumption of increasing prices for primary energy carriers and CO_2 certificates according to the underlying scenarios, the spot market prices reach an average of approx. 100 €/MWh.

In comparison to the scenario without additional capacity, Norwegian hydropower creates an additional value for the European power system by integrating surplus RES generation and smoothening conventional power plant dispatch. The determined specific annual cost reduction was 130 EUR/kWa in scenario B and 148 EUR/kWa in scenario C.

The effect of reserve exchange between the European countries on the total variable system costs was quantified to a saving of 345 mil €/a in scenario B and 70 mil €/a in scenario C.

In the microeconomic investigations, the contribution margin of a 1 GW Norwegian pumped storage plant on the German market was simulated at up to 560 mil €/a mainly resulting from selling energy from natural inflows at the spot market. The combined marketing of the RES portfolio with a Norwegian PSP results in an additional benefit (portfolio effect) of up to 0.9% of the achievable annual contribution margin on the markets for scheduled energy and reserve. For the mixed portfolio, this value reaches up to 0.4%. Furthermore, the portfolio effect is slightly higher in scenario B than in scenario C. In an additional investigation, the benefit of the flexibility from a Norwegian PSP in an RES portfolio under consideration of prognosis errors was calculated. The simulations optimized the spot marketing and portfolio balancing with historical prices for one year and determined a maximum portfolio effect of approx. 2.4%.

The results of the European market simulations and the portfolio optimizations showed that the benefit of having access to Norwegian hydropower is dependent on the available flexibility in the considered system:

- The additional value from flexible Norwegian hydropower for the power system in a European scale is significant. However, import of flexibility from Norway requires the strong expansion of transmission capacities in the North Sea. Assuming current investment costs for hydropower capacity in Norway and the corresponding sea cables, a benefit from a system point of view can be achieved.

- Reserve exchange between countries comes with an additional benefit for the power system by reducing the cost for reserve provision. In the simulations, the cost reduction potential for the TSO is higher in scenarios with low flexibility within the European countries.

- The benefit of a 1 GW Norwegian pumped storage plant for a generation portfolio in Germany is between 503 mio.€/a and 575 mio.€/a. Portfolios with low inherent flexibility like wind and solar power plants benefit more from hydropower than mixed conventional and RES portfolios. Additional benefit results from compensating RES prognosis errors.

7 Literature

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Appendix

Transfer Capacities between Market Areas

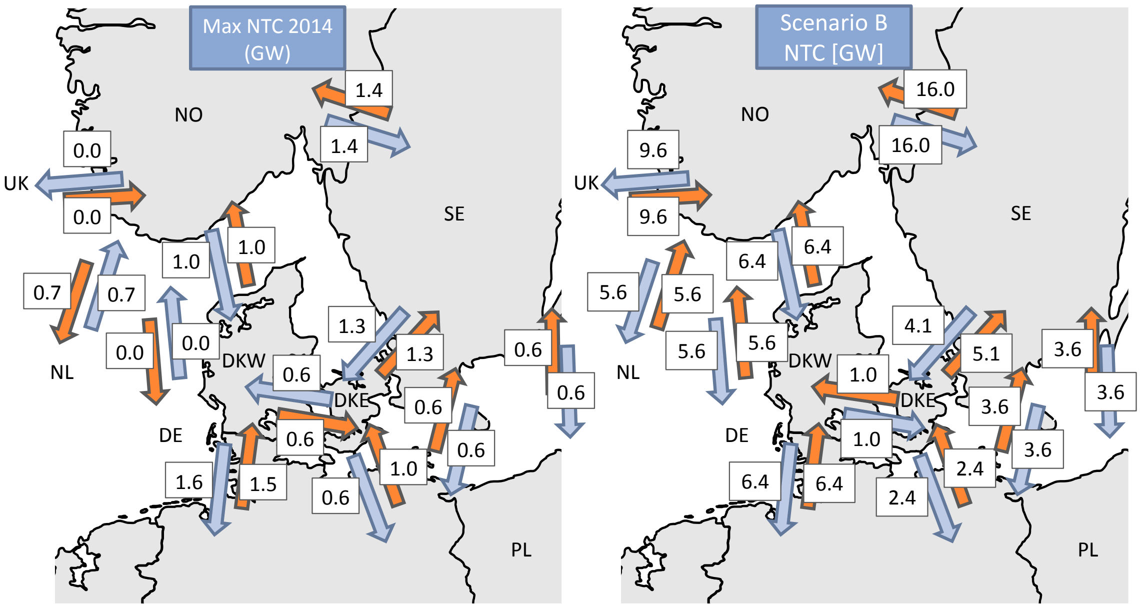

Figure A.1: Transfer capacities from and to Scandinavia in comparison to 2014 NTC values

Table A.1: Transfer capacities between market areas in scenario B

		Import																							
Export	GW	AT	BE	CH	CZ	DE	DKE	DKW	EE	ES	FI	FR	HU	IT	LT	LU	LV	NL	NO	PL	PT	SE	SI	SK	UK	Σ
	AT			0.7	0.9	5.7							1.2	1.6									1.4			11.5
	BE					1.6						5.4				0.6		3.4							2.0	13.0
	CH	1.8				7.5						3.2		6.2												18.7
	CZ	1.5				4.8														1.2				3.3		10.8
	DE	6.3	1.6	6.8	1.7		2.4	6.4				4.8				3.5		6.3	5.6	4.8		3.6			2.0	55.7
	DKE					2.4		1.0														5.1				8.5
	DKW					6.4	1.0											1.4	6.4			1.4				16.6
	EE										1.5				0.0		2.0									3.5
	ES											5.6									4.7					10.2
	FI								1.5													8.1				9.6
	FR		7.1	5.6		4.1				5.6				6.3											9.0	37.5
	HU	1.2																					1.1	2.1		4.4
	IT	2.1		2.7								3.9											0.9			9.6
	LT								0.0								2.3			2.3		0.9				5.4
	LU		0.6			4.1																				4.7
	LV								2.2						2.0											4.1
	NL		3.4			6.3		1.4											5.6						6.0	22.7
	NO					5.6		6.4										5.6				16.0			9.6	43.2
	PL				2.7	4.7									2.3							3.6		0.9		14.1
	PT									4.8																4.8
	SE					3.6	4.1	1.4			8.0				0.9				16.0	3.6						37.6
	SI	1.4											1.1	3.1												5.5
	SK				1.8								5.6							0.8						8.1
	UK		2.0			2.0						9.0						6.0	9.6							28.6
	Σ	14.3	14.7	15.7	7.1	58.7	7.5	16.6	3.7	10.4	9.5	31.8	7.8	17.2	5.1	4.1	4.3	22.7	43.2	12.6	4.7	38.8	3.3	6.3	28.6	

Table A.2: Transfer capacities between market areas in scenario C

		Import																							
	GW	AT	BE	CH	CZ	DE	DKE	DKW	EE	ES	FI	FR	HU	IT	LT	LU	LV	NL	NO	PL	PT	SE	SI	SK	UK	Σ
Export	AT			0.5	0.6	3.8							0.8	1.1									0.9			7.7
	BE					1.6						3.6				0.4		2.4							2.0	10.0
	CH	1.2				5.0						2.1		4.2												12.5
	CZ	1.0				3.2														0.8				2.2		7.2
	DE	4.2	1.6	4.5	1.1		1.2	5.6				3.2				2.3		6.3	4.9	3.2		1.8			0.0	39.9
	DKE					1.2		1.0														3.4				5.6
	DKW					5.6	1.0											1.4	5.6			1.4				15.0
	EE										1.0				0.0		1.4									2.4
	ES											3.7									3.1					6.8
	FI								1.0													5.0				6.0
	FR		4.7	3.7		2.7				3.7				4.2											6.0	25.0
	HU	0.8																					0.7	1.4		2.9
	IT	1.4		1.8								2.6											0.6			6.4
	LT								0.0								1.5			1.5		0.6				3.6
	LU		0.4			2.7																				3.1
	LV								1.5						1.3											2.8
	NL		2.4			6.3		1.4											4.9						2.0	17.0
	NO					4.9		5.6										4.9				14.0			4.9	34.3
	PL				1.8	3.1									1.5							1.8		0.6		8.8
	PT									3.2																3.2
	SE					1.8	2.6	1.4			5.0				0.6				14.0	1.8						27.2
	SI	0.9											0.7	2.1												3.7
	SK				1.2								3.7							0.5						5.4
	UK		2.0			0.0						6.0						2.0	4.9							14.9
	Σ	9.5	11.1	10.5	4.7	41.9	4.8	15.0	2.5	6.9	6.0	21.2	5.2	11.5	3.4	2.7	2.9	17.0	34.3	7.8	3.1	28.1	2.2	4.2	14.9	

Influence of restricted Market Share at the Reserve Market

The market share of each generation portfolio in the portfolio dispatch optimization was restricted to the results of the detailed market simulation. The total market share therefore equals the sum of the reserve provision by the units of the portfolio resulting from the dispatch optimization of the whole German system (compare chapter 3.3). In order to evaluate this effect the portfolio dispatch was also performed without any market share restrictions

The resulting contribution margin for the mixed portfolio and the Norwegian PSP is shown in Figure A.2.

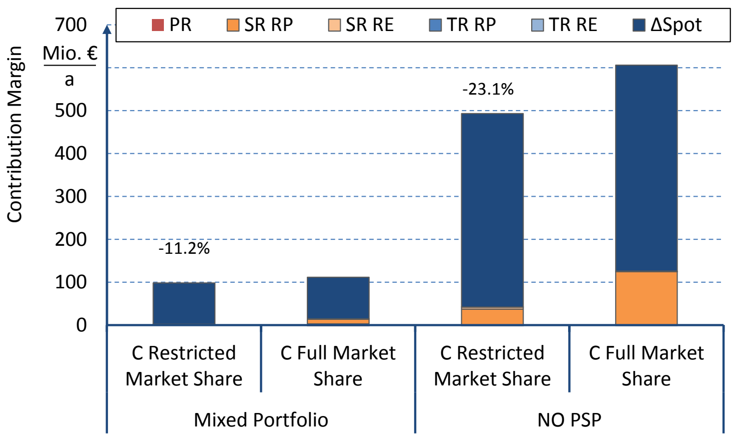

Figure A.2: Influence of restricted reserve market share on portfolio contribution margin

The effect of the restricted reserve market share on the contribution margin of the mixed portfolio is rather small and only leads to a decrease of 11.2%. For the Norwegian PSP the influence is much more significant and leads to a decrease in contribution margin of 23.1%. The PSP is highly flexible and thus can generate a bigger share of its contribution margin on the reserve markets. Especially the negative secondary reserve market appears to be attractive for the PSP in the simulations.

Dispatch of Norwegian Hydropower without additional Transfer Capacity

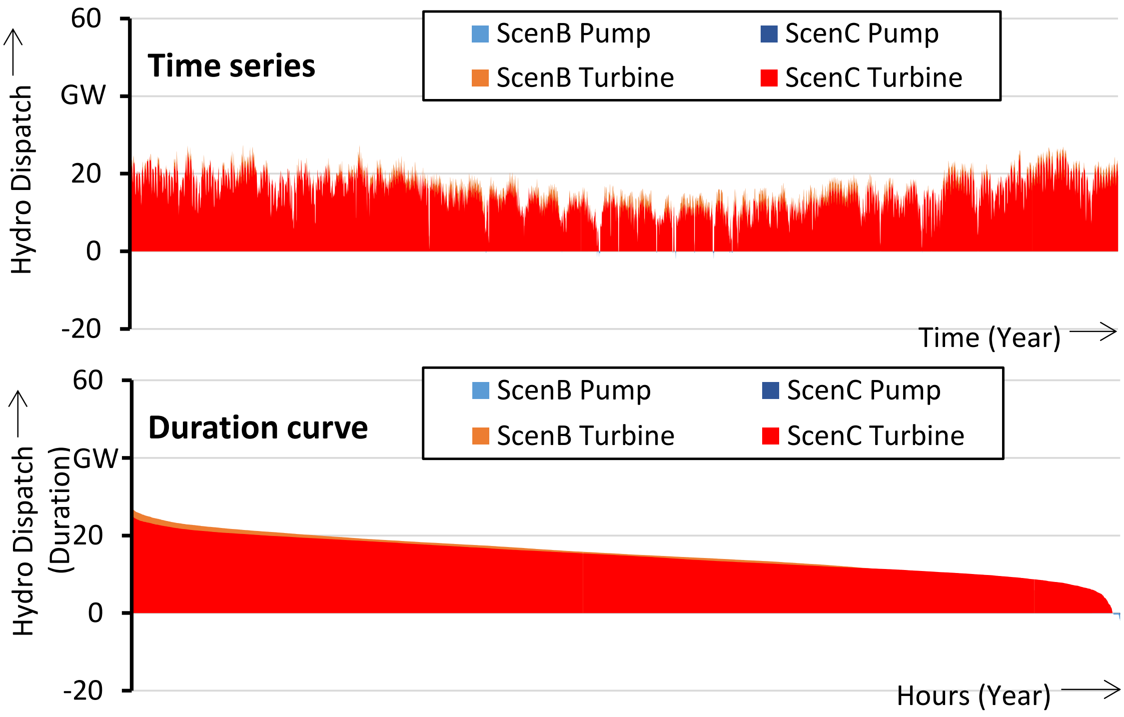

Figure A.3: Dispatch of hydropower in Norway without additional transfer capacity