Balancing future variable wind and solar power production in Central-West Europe with Norwegian hydropower

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ABSTRACT

Norwegian hydropower has an excellent potential to balance power production in a future Central-West European power system with large shares of variable wind and solar resources. The assessment of the realistic potential for Norwegian hydropower to deliver flexibility is based on two pillars, adequate hydropower modelling and the sufficient geographical area covered in the model. Analyses are done with state-of-the-art models including a detailed description of cascaded water-courses with more than thousand reservoirs. Interoperability between hydropower and renewable energy sources is ensured as the entire European electricity generation from renewables with high geographic and temporal resolution is included in the study. To properly account for the full uncertainty of weather variables, many historic years of climate data are applied. The results show that without more flexibility in generation or demand, power prices become very volatile and show expedient periods with capacity deficit and curtailment of demand. Prices vary significantly both from hour-to-hour and from year-to-year. Increases in flexible hydropower provide large benefits to the system: significantly decreasing peak prices and reducing the involuntary shedding of demand. As short-term effects become increasingly important due to large-scale integration of renewable energy sources the correct modelling of flexible hydropower is highly important.

1. Introduction

Variable non-dispatchable wind and solar power production is expected to constitute a large share of the future low greenhouse gas (GHG) emission European power production [1]. In the current power system, dispatchable power plants are used to balance the net load. Increasing shares of wind and solar power production cause long periods with low power prices. Low prices in combination with tighter emission constraints will push present fossil production out of the market. New measures will become necessary to balance the variability in the power production. Several recent studies assess the requirements for flexibility in the future European power system. For example [2] points to the significant increase in variability from RES (Renewable Energy Sources) and the impact on flexibility requirements. The authors identify three main factors, which determine the required flexibility, being: the penetration of variable renewables, the renewable generation mix and their geographic distribution. These factors define a framework in which challenges from RES integration should be evaluated. Among others, [3] identify two main challenges driving the need for flexibility, being known ramps such as the duck-curve and unknown ramps from forecast errors. Both challenges require dispatchable flexible generation or demand side measures but in the latter case regulation speed is extra important. Hydropower can be one of the technologies supplying both dispatchable flexibility and fast regulation [4]. That paper points out the ability of hydropower to deliver different services ranging from ancillary services to seasonal flexibility.

Countries with abundant hydropower resources already use their reservoirs as buffers to balance variable generation [5]. For example, the Canadian province of Manitoba has a largely hydropower-based system that is strongly connected with the neighbouring grids of US Mid-West. Manitoba Hydro utilise their hydropower reservoirs to balance the output of major windfarms in the US. Another example mentioned in [5], is Norwegian hydropower balancing variable wind power production in Denmark. Norway can be one of the main providers of flexibility to continental Europe [6]. It is also shown that the construction of single direct links across the North Sea and thereby providing the potential to utilise the flexibility of hydropower to integrate RES results into an increase in welfare [7].

The hydropower reservoirs in Norway represent approximately half of the total hydro storage capacity in Europe with about 85 TWh of storage [8]. The main purpose of hydro reservoirs in Norway is to store water from the warm season to the cold season and from wet years to dry years. The storage capability of the reservoirs is particularly important for consecutive dry years. The average exploitable inflow to the Norwegian hydropower system in the period 1981-2010 was 133.4 TWh/year. However, in the period 1958-2016 there was a difference of 76 TWh in inflow in the driest compared to the wettest year [9]. Currently, Norway has little pumped-storage capacity, while seasonal pumping of inflow is quite common. If pumped-storage capacity is increased this would increase the flexibility even more. In a long-term perspective, with more wind and solar energy resources, Norwegian hydropower with it its superior flexible capabilities will be able to balance significant shares of the power production from RES in neighbouring countries, drive cost down, and increase reliability.

There are several studies assessing the interplay between hydro-, wind and solar power production. Some are for a single country [10, 11], a part of a country [12] or for a small isolated system [13, 14]. None of the papers is about one country's hydropower system balancing the variable production in a large neighbouring region.

A previous study identifies state-of-the-art related to the use of Nordic hydropower for delivering flexibility and balancing of variable power generation from wind and solar resources in the future Central-West European power system [15]. An early assessment of balancing a 2030 wind dominated European power system with Norwegian hydropower concludes that generation constraints and exchange capacity, and not the aggregated reservoir size, are the most limiting factors [16]. The potential cross-border provision of reserve capacity and balancing energy in Northern Europe is studied in [17]. It is shown that there is a good potential in providing reserves from Norwegian hydropower to balance large-scale wind power production. A more detailed case study of how Norwegian hydropower can be exploited and what transmission capacity is required to supply the flexibility is assessed in [18]. The study shows, that given HVDC (High-Voltage-Direct-Current) interconnectors between Southern Norway and the Netherlands/Germany, Norwegian hydropower can function as an excellent buffer and directly reacts to the variations in power generation from RES in the North Sea area. The profitability of the expansion of transmission capacity in the North Sea area given large-scale power production from wind is studied in [19]. The study points out the profitability of interconnectors between the Nordic countries and continental Europe. Expanding these corridors enables the supply of flexibility from hydropower to balance variable wind power production. The use of Norwegian hydropower in a future, 100% renewable electricity supply system in Germany is simulated in [20]. It is concluded that the flexibility provided from Norwegian hydropower is essential to ensure security of supply at all time.

All of the previous references indicate a good potential for Norwegian hydropower to deliver flexibility support to Europe's RES integration. However, as discussed in [15] none of the studies combines very large shares of RES, a detailed representation of Norwegian hydropower, and has a geographical scope to identify the true variability of the future RES production. The aim of this paper is to do so. Use of detailed representation of the water courses with technical and environmental restrictions will provide the possibility to evaluate a more precise potential for flexibility provision from Norwegian hydropower compared to earlier studies. From this the value for the European power system can be studied in greater detail, including the effect on the power prices of utilising Norwegian hydropower to balance production in a RES dominated Europe.

A previous study shows how increases in Norwegian hydropower generation capacity and flexibility export will impact the Norwegian system [21]. The analysis presented in this paper is based on similar assumptions as [21], but focuses on the effects for the European power system.

2. Methods

The future development of the power system in Europe is analysed by two stochastic optimisation and power market simulators: EMPS and FANSI. EMPS (Elektrisitetsforsyningens Forskningsinistitutt's Multi area Power market Simulator) is described in Section 2.1. EMPS is a well-tested model used for decades by all main market players in the Nordic power market for long-term production planning, price forecasting and expansion planning. However, EMPS was developed for a less variable power market with longer timesteps. The FANSI (FAN Simulator) model is a new model that solves the same problem as EMPS, so far in a prototype version, see Section 2.2. The FANSI model is developed to better include short-terms effects like variable wind and solar resources, hourly pumping, ramping and transmission grid constraints. Since FANSI is still a prototype, the well-tested EMPS is used as a reference to results from the FANSI. In addition, results are more robust if they are reproduced or compared to results from another model. Both models, FANSI and EMPS, use the same dataset. This dataset contains a very detailed representation of the Nordic hydropower system in combination with aggregated data for the power systems in the rest of Europe. However, the models of Germany and UK have higher spatial resolution compared to other non-Nordic countries. The EU 7th Framework project eHighway2050 scenario 100 % RES (also called X-7) is used to define the future European power system. This paper uses the name High-RES of the scenario, since it is not in fact a 100% RES scenario. The data model for the Nordic hydropower system is from the EU 7th Framework project TWENTIES, see Section 2.4. TWENTIES define different levels of hydropower capacity for Norway: 30 GW as of today, increase to 41 GW, and increase to 49 GW.

2.1 Widely used optimisation model for hydro-thermal systems

EMPS is a stochastic optimization model that maximizes the expected total economic surplus in the simulated system through the dispatch of generation and transmission, given a consumption profile [22]. The goal is to find the strategy that maximise the social welfare, considering weather uncertainties. One of the EMPS' strengths is an advanced representation of future cost of power systems operation with energy storage. There is no significant production cost for hydropower. However, with stochastic inflow and limited hydro storage determination of an optimal strategy for hydropower generation becomes a complex problem. EMPS executes two phases: the strategy and the simulation phase. In the first phase, water values for each reservoir are calculated as option values of the stored energy for different operational strategies. In the second phase, the operation of the power system is optimized and simulated for the different stochastic outcomes (climatic years). The model optimises the power dispatch in each time step per node. The optimization procedure starts with calculating the optimal dispatch with hydropower aggregated to one plant and one reservoir per node/region (see Figure 1). In a next step, the aggregated production is distributed on the individual hydropower plants based on advanced heuristics. This ruled-based procedure verifies if the desired production at aggregated level is obtainable within all constraints at the detailed level. If the aggregated production is not possible taking all details in the hydropower system into consideration, the loop continues with a new dispatch at aggregated level and a new reservoir drawdown procedure etc.

The main inputs to the model include costs and generation capacities, net transmission capacities and electricity consumption with price elasticity and information about historical climate variables like temperatures, hydro inflow, wind, solar radiation, typically with hourly resolution. The output from the model is a detailed dispatch of the power system, including power balances, transmission exchange and regional prices.

Figure 1 shows the 59 nodes/regions used in this study. Red nodes represent aggregated onshore production and demand. Blue nodes represent aggregated offshore wind power production. Each node has an endogenously determined internal supply and demand balance with distinct import and export transmission capacities to the neighbouring nodes. As shown in the Figure, the Nordic countries, UK and Germany are modelled with several nodes, while South-Eastern Europe is aggregated to one node (59_ro). Hydropower in the Nordic area is described as detailed water courses with multiple power plants in series or parallel. The description includes minimum and maximum reservoir levels, minimum discharge requirements and others. The remaining European countries use an aggregated model for the hydropower.

The temporal resolution of the EMPS model is flexible, but calculation time increases significantly with more time steps. This present analysis uses 2 hours resolution for weekdays and 4 hours for weekends. To keep the problem computational tractable, the opinion to include start- up costs for thermal power plants have not been applied.

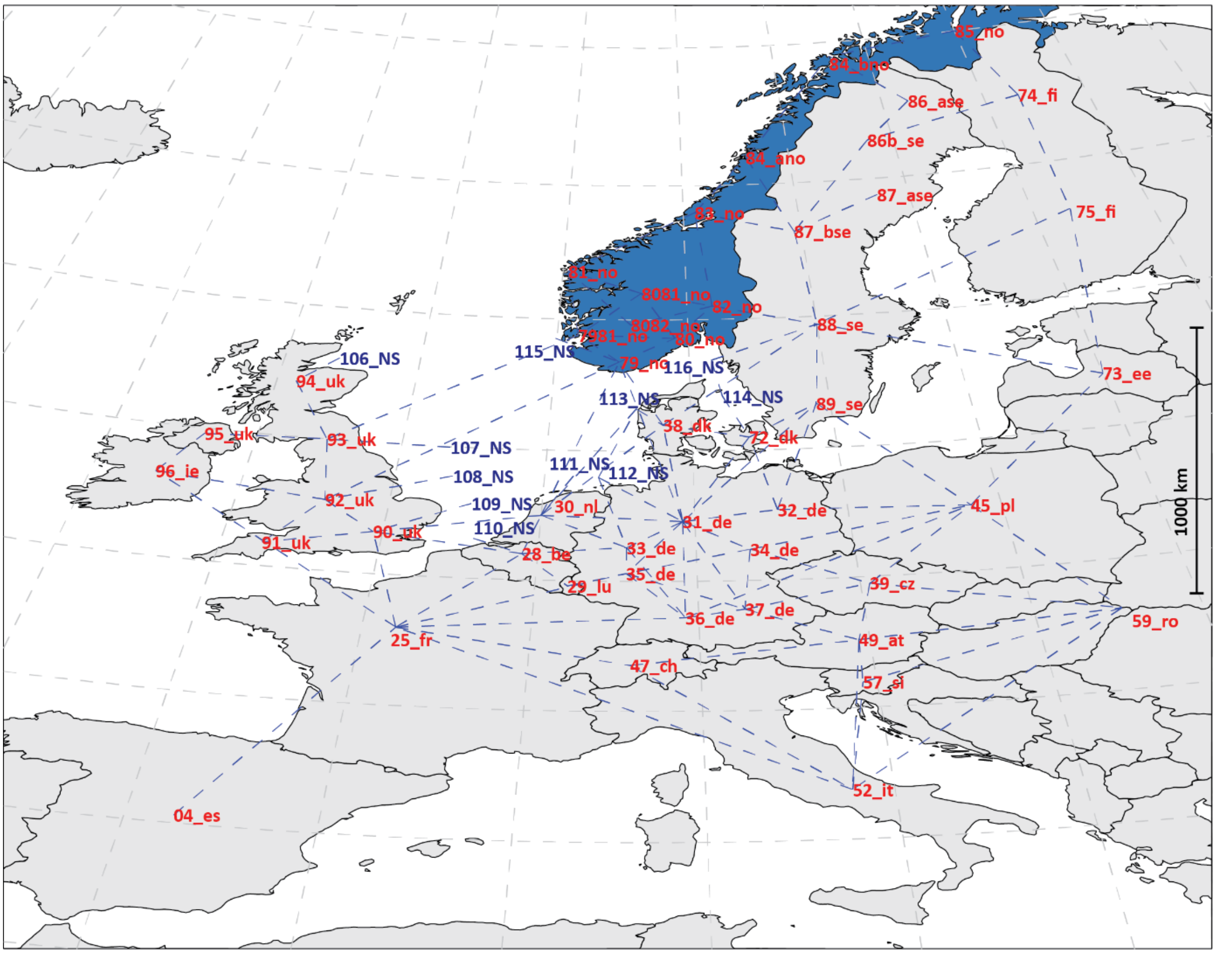


Figure 1 Nodes (regions) in the EMPS and the FANSI analysis

2.2 The next generation power system modelling tool

To assess short-term flexibility of the Norwegian hydropower system in more detail the FANSI model is applied in addition [23]. In contrary to the mixture of optimization and heuristic in EMPS, the FANSI model uses a formal optimisation, when determining the dispatch of the individual hydropower plants in the detailed water courses. The drawback is high computation expense. In this analysis, the difference between FANSI and EMPS is the optimisation of the hydropower utilization in the operational problem only. Except for this difference, the models are run in an equal way. Two aspects with the optimisation of the hydropower utilization are particularly important for the results:

i) FANSI has a better representation of short-term flexibility e.g. pumped-storage. EMPS seldom pumps in the winter due to its rule-based heuristics methods.
ii) FANSI distributes the water in the long cascade coupled rivers system such that plants with high capacity have as much water as possible upstream to the plant. EMPS distribute the water such that the risk for empty reservoirs in the winter or overflow in the spring and summer is minimised.

The consequence is that FANSI has more water available for production in high price periods particularly in the late winter/spring.

2.3 Modelling of wind and solar power production

Calculation of wind and PV power production is based on Reanalysis data from 1948 to 2005. Wind speed and irradiation time series are from NCEP data provided by NOAA/OAR/ESRL PSD, Boulder Colorado USA from their Web site [24]. The spatial resolution of the data is 2.5 degrees both in latitude and in longitude. Generation of hourly resource values and calculation of the power production from wind and radiation sources are conducted for each of the regions in Figure 1 [25] and validated in [26]. The offshore wind production in the North Sea is adjusted to a capacity factor of 40% in order to be in accordance with present results [27].

2.4 Expansion of the Norwegian hydropower system

The present production capacity in the Norwegian power system is about 30 GW. Previous research shows possibilities for an increase in capacity for existing hydropower plants in South-West Norway [28]. The reference focuses on increasing generation capacity with minimal environmental impact. It assumes no new reservoirs or expansions of reservoirs. Furthermore, it keeps present regulations regarding highest and lowest regulated water levels unchanged. The reference identifies two cases: one with 11.6 GW increased production capacity and 4.5 GW pumping capacity and another with 18.5 GW increased production capacity and 9.2 GW pumping capacity, see Table 1. In the table, the increases are aggregated per EMPS region (see Figure 1).

Table 1 Increases of production capacities and pumped storage in South-West Norway [28]

		11 GW			19 GW		
EMPS area (see Figure 1 and Figure 3)	Present capacity [GW]	New capacity [GW]	Increase [GW]	Pump capaciy [GW]	New capacity [GW]	Increase [GW]	Pump capaciy [GW]
79_no	4.1	7.6	3.5	1.4	8.3	4.2	1.4
7981_no	3.6	7.8	4.2	2.1	10.1	6.5	3.4
81_no	5	7.9	2.9	0	8.5	3.5	0
8081_no	2.1	3.1	1	1	6.3	4.3	4.4
TOTAL	14.8	26.4	11.6	4.5	33.2	18.5	9.2

58 years with historical hydrological inflow data are used in the simulations. The reason for using so many years is the large variation in inflow to the Norwegian hydropower system (See Section 1).

2.5 The eHighway2050 scenarios

This study uses production and transmission capacities, annual demand and fuel prices from a eHighway2050 scenario [29], see Appendix A. In the eHighway2050 project, 28 research partners (including among other ENTSO-E) developed scenarios that aimed to fulfil EU's Climate target and ambitions to 2050. The scenarios have high spatial resolution including e.g. several regions within each country. One of the scenarios, 100% RES (also called X-7), assumes large-scale deployment of both onshore and offshore wind and PV power production. Even though the scenario is called 100% RES, it includes gas for peak power production. Thus, this study uses the name High-RES instead. Figure 2 shows the aggregated installed capacities for Europe for the High-RES scenario. Run-of-River (RoR) production of about 296 TWh/year comes in addition. The demand assumption for the whole Europe is 4277 TWh/year. This study uses present (2015) annual demand profiles from ENTSO-E [30].

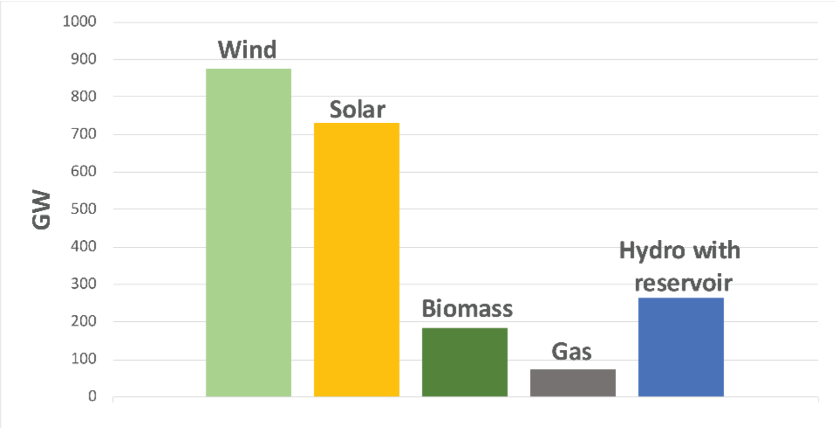


Figure 2 Installed capacities in Europe in the original eHighway2050 High-RES scenario [29]

EMPS analysis of the High-RES eHighway2050 scenario showed a system in large imbalances. To get a more realistic system, capacity was added, see Section 3.1.

As shown in Appendix A, there is assumed large increases in transmission capacities in Europe. Figure 3 shows the European regions that is mainly focused in this study. It also shows the assumed interconnectors between Norway, the Netherlands, UK and Germany.

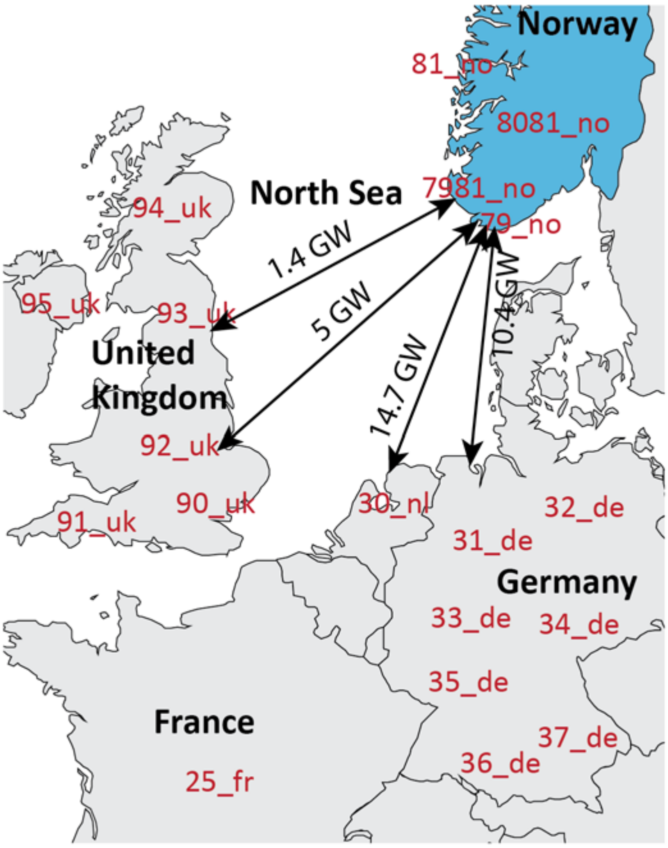


Figure 3 The European regions that are mainly focused in this study.

3. Results

In this section, the power prices for the High-RES scenario without any increases in the capacity in the Norwegian hydropower system is investigated, see Section 3.1. The purpose is to understand some characteristics of the system in 2050. In a next step, the hydropower generation capacity in Norway is increased and analysed to show how such an increase impacts the power system, see Section 3.2. In addition, in Section 3.3 sensitivity analyses are included.

3.1 The "High-Renewable Energy Source" eHighway2050 scenario – no extra capacity in the Norwegian hydropower

The EMPS analysis of the eHighway2050 High-RES scenario in its original versions shows a system, which is not in balance. Long periods with demand curtailment (rationing) can be observed throughout Europe. EMPS showed on average rationing of about 35 TWh/year (0.8% of total load). E.g. for the Netherlands there are 578 hours/year with rationing of demand. These hours result in very high average power prices, 1400-1700 Euro/MWh for the Netherlands, UK, France and Germany. eHighway2050 used Antares for system simulations. Antares uses Monte-Carlo simulation, while this paper uses real weather data [29]. To get a more realistic system, extra capacity was added. This paper includes an alternative with nuclear as extra capacity and another alternative with gas as extra capacity (see Section 3.3). The nuclear is assumed to be cheap and inflexible while the gas is expensive and very flexible. In such a way, two extreme variations of the future system are explored. Since this is a 100% RES scenario, RES is assumed to be fully utilised. The nuclear capacity and locations are from the X-5 scenario in eHighway2050. That extra capacity resulted in a lot of surplus. Thus, the nuclear capacity was reduced 40% in all regions compared to the X-5 scenario. The assumed capacities in eHighway2050 reflect long term ambitions and targets in each country. E.g. there is no nuclear power production in Germany.

Figure 4 shows the difference between the scenario in its original version and the same scenario with extra nuclear added. The results are for the whole Europe and averaged over 58 years with simulations. For both versions, the wind and solar power plants produce 1766 TWh/year and 850 TWh/year respectively. Variable wind and solar power production supply 61.2% of the demand (4277 TWh/year).

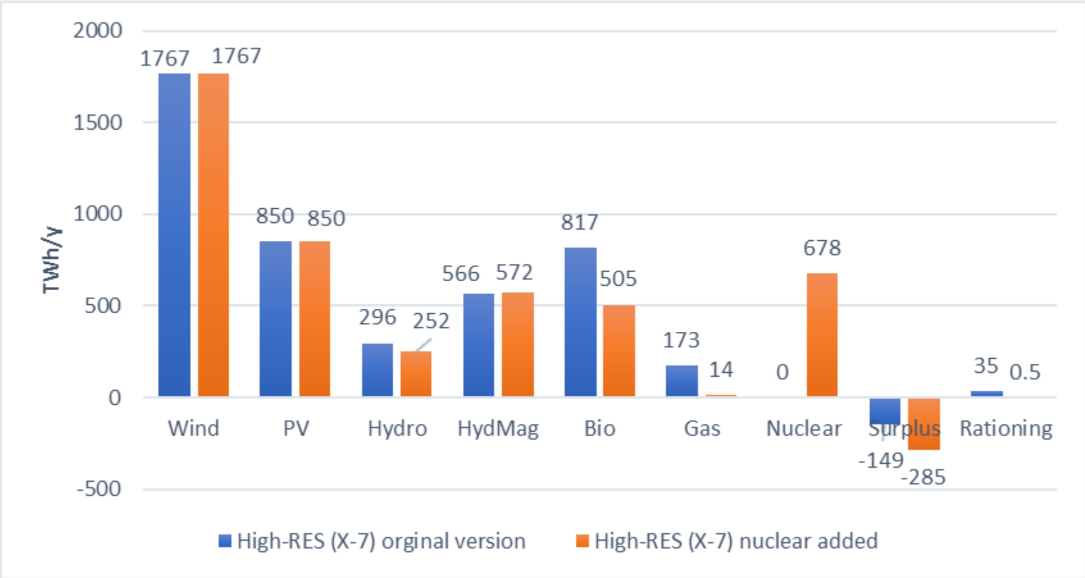


Figure 4 Main differences in annual power production between High-RES scenario original version and High-RES with nuclear added, results for the whole Europe

The rationing of demand is on average 0.5TWh/year with extra nuclear added to the High-RES scenario. However, there is on average 285 TWh/year in production curtailment (surplus), i.e. the surplus is 6.6% of the total demand of 4277 TWh/year. To assess the effects on the continental European power system, the Netherlands are used to analyse power prices, as it has a rather tight connection to Southern Norway via HVDC interconnector. Figure 5 shows the power prices in the Netherlands for the High-RES scenario with nuclear added. The figure to the left shows the power price averaged hour-by-hour for 58 years with simulations. The figure to the right shows the average price per year for the same years. As shown in Figure 5, the prices are very volatile. The reasons for the price variability are variation in demand, wind, solar and hydro resources. In periods with lack of those renewable resources compared to the load, there will be prices close to rationing prices (10000 Euro/MWh) that significantly impacts average prices.

Figure 5 to the left shows the prices are varying a lot in the beginning of the year. There are 332 hours/year with prices above 500 Euro/MWh. Furthermore, the figure to the right shows that the average prices vary a lot from year to year. The annual average price increases with the number of hours with prices close or equal to the rationing price. The highest average price is for year 50: 183 Euro/MWh. In year 7, there is no rationing of demand at all. In year 50, there are many hours with rationing prices due to many hours with low production from the wind and solar power plants.

Figure 6 to the left shows the power price in the Netherlands hour-by-hour for year 50, with about 133 hours with rationing prices.

Figure 6 to the right shows the highest part of sorted price curves for the Netherlands for the year 7 and the year 50. As shown in the figure, there are prices around 203 Euro/MWh (marginal price for gas) for less than 300 hours in year 7. For year 50, the number of hours with such prices are around 800.

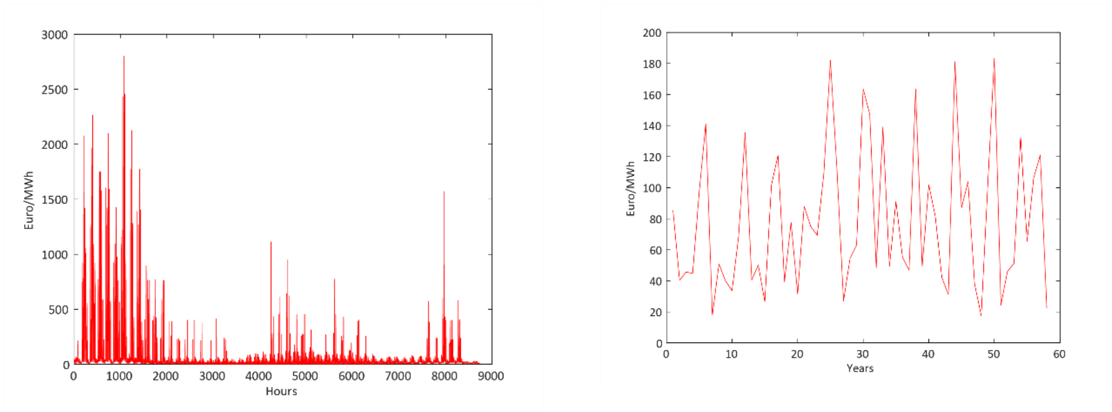


Figure 5 Power prices in the Netherlands for the High-RES eHighway2050 scenario with extra nuclear, average for 58 simulation years. To the left: average prices hour-by-hour. To the right: average prices year-by-year.

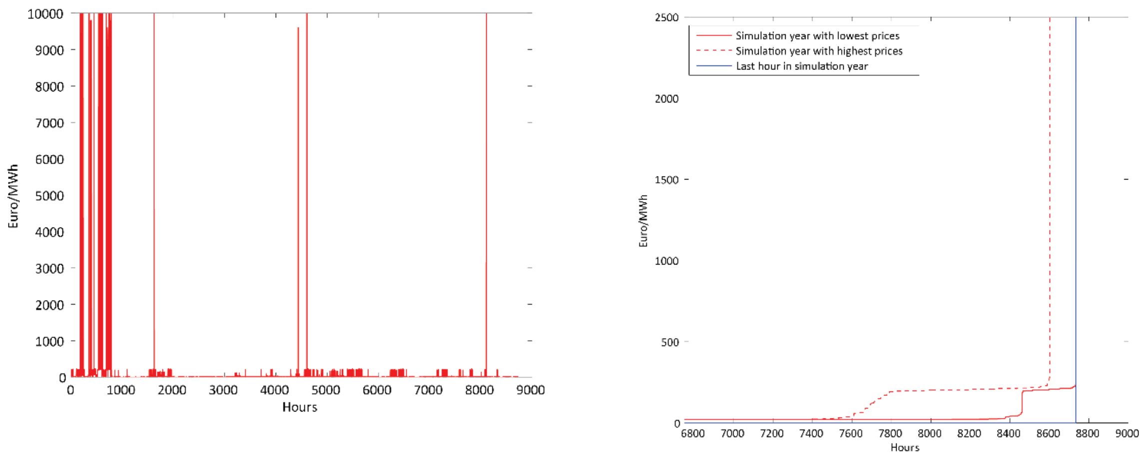


Figure 6 Price curves for the Netherlands High-RES scenario with extra nuclear. To the left: hour-by-hour for year 50. To the right: highest part of sorted prices curve for year 7 and year 50.

Figure 7 shows the aggregated wind and solar power production versus the power price in the Netherlands for hour 0-2000 in year 50. As shown in the figure, periods with very low production from the wind and solar power plants leads to rationing prices.

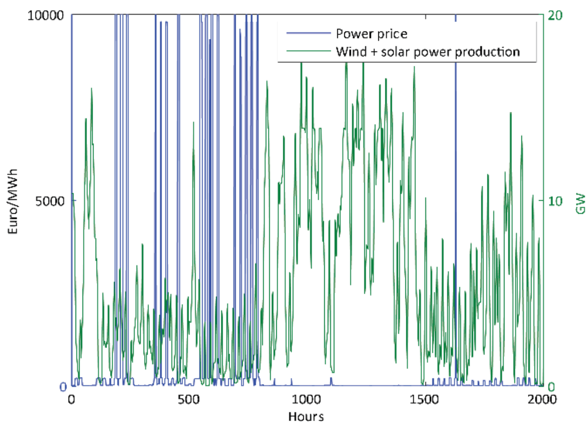


Figure 7 Aggregated wind and solar power production versus power price for the Netherlands in hour 0-2000 in year 50, High-RES scenario with extra nuclear.

3.2 The "High-Renewable Energy Source" eHighway2050 scenario with extra nuclear and extra capacity in the Norwegian hydropower

With the previous results in mind, it was assessed how Norwegian hydro power production can balance the variable power production from wind and solar resources. The hydropower generation capacity in the High-RES scenario is expanded by 11.6 GW production and 4.5 GW pumping capacity (called 11 GW extra capacity in the following text) and 18.5 GW production and 9.2 GW pumping capacity (called 19 GW extra capacity in the following text), see Table 1. These expansions of 11 and 19 GW are analysed with EMPS. Figure 8 to the left shows hourly average power prices for the 58 climatic years which are simulated. As shown in the figure, the prices are reduced for the case with 11 GW extra capacity compared to the case with present capacity (0 GW extra capacity).

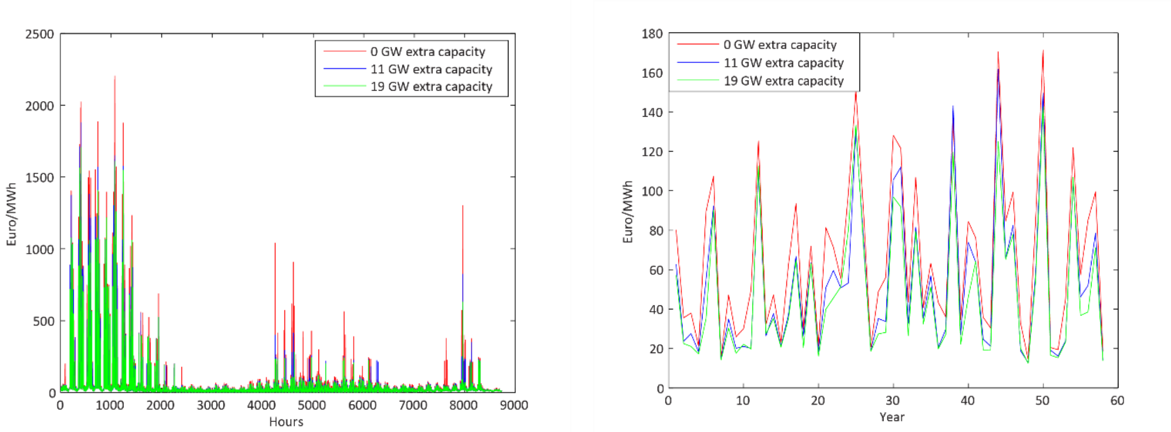


Figure 8 Power prices in the Netherlands and with extra capacity in the Norwegian hydropower system based on 58 years with EMPS analysis. To the left: Average prices hour-by-hour. To the right: Averaged prices year-by-year

Table 2 shows the prices reduction for regions connected to South-West Norway. In addition, the table shows impact on prices in France, since France, Germany and UK are the largest power consumer in Central-West Europe. As shown in the table, there is a great price reduction by adding capacity in the Norwegian hydropower system. The reductions are from 20.1 – 25.1% for 11 GW extra capacity. The very high rationing prices contribute to the high percentage effect. There is a significant impact on the average price if the price in some situation is reduced from a rationing price of 10000 Euro/MWh to a few hundred Euro/MWh (gas price = 203 Euro/MWh). There is less impact on the prices in UK than in the Netherlands and Germany, since the cables between Norway and UK are fully loaded over long periods. The price reduction/GW-increase in the Norwegian hydropower system is less for 19 than for 11 GW. The reason is that there is not sufficient water in the reservoirs for some periods in the 19 GW case [21].

Table 2 Annual power prices for selected regions 11 and 19 GW increases in capacity in Norwegian hydropower, High-RES scenario with extra nuclear EMPS model, 58 years with simulations

	0 GW				11 GW				
Euro/ MWh	Average power price	Standard deviation	Min value	Max value	Average power price	% change 0-11 GW	Standard deviation	Min value	Max value
25_fr	70	607.4	0.004	9800	52.4	25.1	519.3	0.0	9800
30_nl	78.6	698.1	0.036	10000	59.1	24.8	570.9	0.0	10000
31_de	77.2	682.7	0.0015	10000	58.4	24.4	561.2	0.0	10000
92_uk	82.6	735.7	0.036	10000	66.0	20.1	639.0	0.0	10000
93_uk	79.8	719	0.092	9800	63.6	20.3	624.0	0.1	10000

	19 GW			
Euro/ MWh	Average power price	Standard deviation	Min value	Max value
25_fr	47.9	491	0.004	9800
30_nl	54	540	0.036	10000
31_de	53.4	531.7	0.0015	10000
92_uk	61	612.9	0.036	10000
93_uk	58.8	599	0.092	10000

Due to the high transmission capacities, the price reductions are similar in many European regions.

3.3 Sensitivity analysis

In addition to the previous cases, the following five sensitivity cases are discussed:

a. Demand flexibility without increases in hydropower capacity
b. Demand flexibility in combination with increases in hydropower capacity
c. Increased annual demand in Norway and Sweden
d. Gas as additional capacity to the High-RES scenario
e. Reduced rationing price=1000 Euro/MWh

a. Demand flexibility without increases in hydropower capacity

An EU Commission Staff working document states: "It is estimated that the volume of controllable load in the EU is at least 60 GW – shifting this load from peak times to other periods can reduce peak-generation needs in the EU by about 10%" [31]. Table 3 quantifies the flexibility in demand used in this analysis. As shown in the table this study uses only 5% reduction of peak generation in the hours with the highest prices. Between those four points defined in the table, there is a linear relationship between the price and the demand. There is no requirement that the reduced demand must result in increased demand within a certain time. The demand flexibility is an option in every time step and in every region in the simulations. The demand reduction in high price periods results in a reduction of demand of about 4 TWh per year for the whole of Europe. The increase in demand in low price periods leads to 0.7 TWh increase in demand per year. The total demand in Europe without flexibility in demand is 4277 TWh/year. The demand is reduced with 3.3 TWh/year (less than 1% of the total load) for the flexibility case, i.e. it is not only a demand flexibility but also a load shedding.

Table 3 Flexibility in demand

Price [Euro/MWh]	350	200	0.1	0.05
Share of demand that must be covered [%]	95	100	100.1	100.2

Table 4 for the columns marked "a" shows the prices for selected regions with and without flexibility in demand. As shown in the table, the flexibility (or reduction of demand) makes a significant difference in the power prices. However, at this stage it is uncertain how much demand flexibility that exists in the system. Thus, further studies with other levels of flexibility in demand are not included.

b. *Demand flexibility in combination with increases in hydropower capacity*

To assess the interplay of demand flexibility and hydropower, the High-RES scenario with extra nuclear and with the demand flexibility described above is combined with increases in capacities in the Norwegian hydropower system. As discussed above, with demand flexibility, the power prices are significantly reduced. Still, by increasing the capacity in the Norwegian hydropower system, the power prices are further reduced. For the selected regions, they are reduced with 13.0-13.8%, see Table 4 columns marked "b". However, flexibility in demand decreases the effect of increasing capacity in the hydropower. As shown in Table 2, without flexibility in demand, increases in hydropower capacity of 11 GW, decreased the prices with 20.1-25.1% for the same regions.

c. *Increased demand in Norway and Sweden*

The demand in Norway and Sweden is lower than in the present system in the High-RES scenario. Several studies of the future Nordic power system expect increases in demand, e.g. the Norwegian System Operator expects that the demand increases with 50 TWh/year in the Nordic region including 15 TWh/year in Norway from 2016 to 2040 [32] . In this sensitivity case, the demand in Norway and Sweden is increased 30% in each region compared to the High-RES scenario. Table A4 in Appendix shows the increases per region. The total demand in Norway and Sweden is increased with 70 TWh/year in this sensitivity case. It is not added any extra power production capacity. Thus, the capacity margins are tighter. With tighter margins, there are more situations with rationing of demand, and the average prices increases significantly. For the case without extra capacity in the Norwegian hydropower system (0 GW), the prices increase from 70.0-82.6 Euro/MWh (see Table 4c) to 101.2-136.6 Euro/MWh for the selected regions. Still, increases in the hydropower capacity, significantly decreases the prices in neighbouring regions.

d. *Gas as additional capacity to the High-RES scenario*

All the nuclear power production was removed and instead flexible gas with marginal price 203 Euro/MWh was added. Start stop costs for the gas were not modelled, since including start/stop costs increase the run time of the EMPS from hours to weeks. The average power prices are much higher with gas as extra capacity instead of nuclear, see Table 4d. This is because gas is modelled with 203 Euro/MWh (see Table A3) as marginal price while nuclear is modelled with 0.05 Euro/MWh (to prevent the nuclear production from increasing and decreasing with variable renewable production). Even with flexible gas, increases in Norwegian hydropower capacity significantly decreases average power prices in neighbouring European regions.

e. *Reduced rationing price=1000 Euro/MWh*

The maximum allowed price in a power market is a much-discussed topic. To assess the effect of the unregular price spike, the effect of decreasing the rationing (maximum) price to 1000 Euro/MWh was tested. Since the rationing price of 10000 Euro/MWh has high impact on the average prices, the prices drop significantly by decreasing the rationing price. The average prices are decreased from 70.0-82.6 Euro/MWh (see Table 4e) to 28.6-31.5 Euro/MWh for the selected regions for the case without extra capacity in the Norwegian hydropower. By increasing the hydropower capacity from present system to 11 GW extra, the average prices are further reduced by 14.0 -15.2%.

Table 4 summarizes the impact on the power prices for the different sensitivity cases.

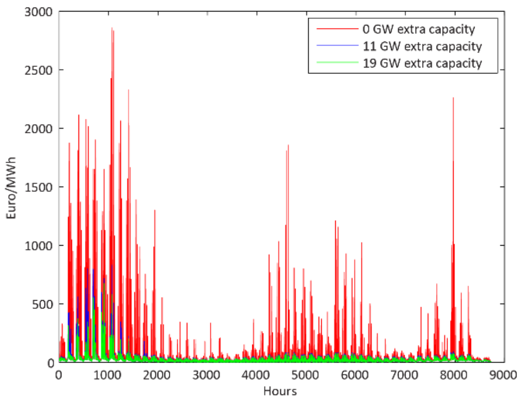
Table 4 Power prices for sensitivity cases a-e analysed with EMPS

Sensitivity case (see explanation above)	a. Demand flexibility without increases in hydropower capacity			b. Demand flexibility in combination with increases in hydropower capacity				c. Increased demand Norway and Sweden			
	Euro/MWh	Euro/MWh	%	Euro/MWh	Euro/MWh	%	Euro/MWh	Euro/MWh	Euro/MWh	%	Euro/MWh
Region (see Figure 3)	Without demand flexibility	With demand flexibility	% reduction	0 GW	11 GW	0-11 GW % reduction	19 GW	0 GW	11 GW	0-11 GW % reduction	19 GW
25_fr	70.0	26.9	61.6	26.9	23.3	13.4	22.4	101.2	82.4	18.6	75.6
30_nl	78.6	29.0	63.1	29.0	25.0	13.8	24.0	136.6	105.0	23.1	93.1
31_de	77.2	28.7	62.8	28.7	24.8	13.6	23.9	133.7	103.4	22.7	91.9
92_uk	82.6	27.7	66.5	27.7	24.0	13.4	23.1	131.6	104.6	20.5	94.1
93_uk	79.8	26.2	67.2	26.2	22.8	13.0	21.9	126.9	100.7	20.6	90.5

Sensitivity case (see explanation above)	d. Gas as additional capacity to the 100% RES scenario				e. Reduced rationing price =1000 Euro/MWh			
	Euro/MWh	Euro/MWh	%	Euro/MWh	Euro/MWh	Euro/MWh	%	Euro/MWh
Region (see Figure 3)	0 GW	11 GW	0-11 GW % reduction	19 GW	0 GW	11 GW	0-11 GW % reduction	19 GW
25_fr	171.7	156.1	9.1	152.6	28.6	24.6	14.0	23.8
30_nl	177.4	155.5	12.3	151.0	31.5	26.7	15.2	25.8
31_de	175.1	154.0	12.1	149.8	31.1	26.5	14.8	25.6
92_uk	182.9	164.1	10.3	160.3	30.6	26.3	14.1	25.5
93_uk	177.0	158.8	10.3	155.2	29.1	25.0	14.1	24.2

3.4 Use of the next generation modelling tool to analyse the "High-Renewable Energy Source" scenario

As discussed previously, short-term variability of production and balancing might not be fully handled with EMPS but can be much better targeted with a formal optimisation model. Hence, the eHighway2050 scenario with extra nuclear, was also analysed with the FANSI model. Figure 9 to the left shows the prices in the Netherlands averaged hour-by-hour over 58 years with simulations. The figure to the right shows the prices averaged year-by-year. As shown in the figure, the FANSI model manage to reduce the peak prices, smooth out the annual average prices and reduce the variation of the prices (the standard deviation) to a much higher degree than EMPS. The greater price reduction is due to the better capability of the FANSI model to uncover short-term flexibility in a complex hydropower system. FANSI pumps water to higher reservoir levels in low-price periods and has more water available for production in high price periods. There is hardly any pumping capacity in the present Norwegian hydropower system. These analyses show that pumping capacity will be very important for being able to utilise the increased production capacity in the high price periods.



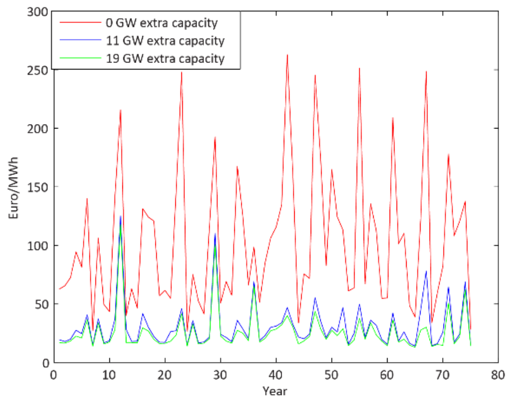


Figure 9 Power prices in the Netherlands and with extra capacity in the Norwegian hydropower system based on 58 years with FANSI analysis. To the left: Average prices hour-by-hour. To the right: Averaged prices year-by-year

As shown in Figure 9, there is a peak in average prices in year 12. In this year, the Netherlands has 65 hours with prices in the range 7600-9800 Euro/MWh. There is very low production from the wind and solar power plants in the Netherlands in those hours. In addition, the cable between the Netherlands and Norway is fully loaded.

Table 5 shows the average prices for FANSI analyses for the same regions as in Table 2. The Table shows the results for the FANSI analyses with 11 and 19 GW extra capacity in the Norwegian hydropower system. The table confirms that the FANSI model manage to distribute the water in a more optimal way than the EMPS model, see Section 2.2.

Table 5 Annual power prices for selected regions 11 and 19 GW increases in Norwegian hydropower capacity, FANSI model 58 years with simulations

	0 GW				11 GW				
Euro/ MWh	Average power price	Standard deviation	Min value	Max value	Average power price	% change 0-11 GW	Standard deviation	Min value	Max value
25_fr	95.6	739.7	0.004	10000	28.0	70.7	253.6	0.1	9800
30_nl	107.9	815.7	0.004	10000	30.8	71.5	272.2	0.1	10000
31_de	106	798.7	0.0015	10000	30.5	71.2	269.5	0.1	10000
92_uk	110.8	844.1	0.004	10000	46.0	58.5	471.6	0.1	10000
93_uk	106.7	823.1	0.092	9800	44.5	58.3	462.2	0.1	9800

	19 GW			
Euro/ MWh	Average power price	Standard deviation	Min value	Max value
25_fr	24.3	206.8	0.1	9800
30_nl	25.8	211.6	0.1	10000
31_de	25.7	210.1	0.1	9907
92_uk	42	447.1	0.1	10000
93_uk	40.6	438.2	0.1	9800

The power prices are higher for FANSI than for EMPS for the 0 GW case. This is because there is no pumping possibility in the 0 GW case. FANSI uses the water in high price periods and ends up with no or limited water in following high prices periods. Since no water is available, gas must be used or even worse: demand is curtailed. These analyses use water values (see Section 2.1) from the EMPS model in the FANSI simulations. The reason for this is that it requires weeks to calculate water values in the prototype model. For the 0 GW case, those values are probably too low for FANSI. With higher water values, FANSI would have had a more optimal utilisation of the water.

4. Conclusions

The aim of this paper is to study the effect of Norwegian hydropower on the power balance in a 2050 Central-West European system with large shares of wind and solar energy resources. Analyses are done with two state-of-the-art numerical models (EMPS and FANSI), which include a detailed description of cascaded water-courses with, in total, more than thousand reservoirs. To sufficiently account for the stochastic nature of weather variables, 58 historic years of climate data (wind, solar and precipitation) are applied. To account for long-distance geographic effects, including bottlenecks in the European transmission, the whole European power system is regarded.

The results of the presented study are two-fold. On the one hand, it is shown that Norwegian hydropower can deliver shares of the required flexibility and contribute to balance the European power system. On the other hand, in order to correctly assess the flexibility, it is essential to take short-term effects into account, while including a detailed description of all the water courses.

The studied cases show very volatile power prices and involuntary shedding of demand during some hours per year, due to variable renewable energy sources. However, the study also shows, that Norwegian hydropower can almost eliminate the hours with load shedding and significantly reduce the prices in the hours with peak load. A prerequisite is increases in the hydropower production capacity from the present value of about 30 GW. In all simulated cases the average annual power prices are reduced by 10% or more by adding 11 GW capacity in the Norwegian production system. The effects will be similar for a main part of Central-West Europe due to high transmission capacities in 2050. The analyses do not assume increases in reservoir capacities or changes of present regulations of minimum and maximum water levels in reservoirs.

The price reduction/GW-increase is less for 19 GW than for 11 GW increase. The reason is that there is not enough water in the reservoirs for some periods in the 19 GW case. The analyses also show that the possibility of pumping is very important to be able to fully utilise the increased production capacity in high price periods. Demand elasticity/reduction of 5% in peak price hours has the same effect on prices as Norwegian hydropower. Further, combining 5% flexibility in demand with 11 GW increased capacity in the hydropower system, significantly decreases power prices in Europe compared to a system without the increased capacity in Norway.

Within the case study, results from the EMPS model, that is widely used in the power industry for modelling hydro-thermal power systems, are compared with results from the next generation power system modelling tool FANSI for a large case for the first time. From the comparison about how the two models are capable of modelling flexibility it is concluded that FANSI has a superior representation of constraints and possibilities in the future power system. The FANSI model shows a much higher reduction of the power prices by increasing Norwegian hydropower capacities than the EMPS model. This outcome verifies the expectations, since FANSI was developed to include more of the short-term flexibility of hydropower and account for the variations in production from wind and solar resources. Hence, as short-term effects become increasingly important due to large-scale integration of renewable energy sources, it is important that flexible hydropower is correctly modelled.

The impacts from the hydropower system may be larger than shown in this study. Study [21] shows that some of the increases in hydropower plant capacity cannot be utilized due to e.g. too small reservoirs upstream to the plant. In-depth studies should be conducted to identify a more optimal location of the increases in capacities and this is recommended for further research. More optimal location of capacity increases may improve the price reduction/GW increase for the 19 GW case. Further research should also explore the economic viability for the hydro power producers to invest in increased generation and pumping capacity.

Acknowledgments: The research is a part of the Norwegian project “Cedren HydroBalance”. The authors thank the Norwegian Research Council and project partners for the financial support to the project.

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APPENDIX

This paper uses the following abbreviations: at–Austria, be-Belgium, ch-Switzerland, cz–the Czech Republic, de-Germany, dk–Denmark, ee-Baltics, es-Spain*, fi–Finland, fr–France, lu-Luxembourg, ie-Ireland, it-Italy, nl-the Netherlands, no-Norway, ns-North-Sea, pl-Poland, ro-Romania*), se-Sweden, si-Slovenia, uk-United Kingdom

*) The node 04_es includes both Spain and Portugal. The node 59_ro includes Romania, Bulgaria, Hungary, Albania, Greece, Croatia, Montenegro, Former Yugoslav Republic of Macedonia, Serbia, Bosnia and Herzegovina and Slovakia. The node 73_ee includes Latvia, Lithuania and Estonia.

Figure 1 shows location of the nodes used in the following tables.

eHighway2050 assumes both PV and Concentrated Solar Production (CSP). All solar power production is modelled as PV in this study. Furthermore, eHighway2050 assumes import of solar power production from North Africa to Europe. This is modelled as extra PV power production in Southern European countries in this study.

Table A1 shows the assumed capacities for the High-RES scenario with extra nuclear and with extra gas.

Table A1 Installed capacities in the High- RES scenario and with extra capacity for nuclear and for gas.

Original eHighway2050 100% RES scenario											
Node/ region	**Wind (GW)**	**Solar (GW)**	**Biomass I (GW)**	**Biomass II (GW)**	**Open-Circle-Gas-Turbine (GW)**	**Run-of-River (TWh/y)**	**Hydro with reservoir (GW)**	**Max reservoir (TWh)**	**Demand (TWh/y)**	**Extra Nuclear (GW)**	**Extra Gas [GW]**
04_es *)	81	130	5	15	9	53	43	30,0	569	5	5
52_it	41	116	4	15	9	26	22	25,9	431	0	0
25_fr	124	114	8	21	16	57	32	9,8	649	43	43
28_be	11	24	1	4	3	2	2	0,3	121	0	0
29_lu	1	1	0	0	0	1	2	0,1	7	0	0
30_nl	15	22	1	4	3	1	0	0,0	161	1	1
31_de	32	15	1	3	2	1	1	0,0	111	0	0
32_de	26	10	1	4	3	0	0	0,0	63	0	0
33_de	12	11	1	2	4	1	1	0,0	145	0	0
34_de	15	14	1	3	1	0	4	0,1	63	0	0
35_de	7	11	1	3	1	0	1	0,0	90	0	0
36_de	2	11	1	2	1	5	4	0,1	88	0	0
37_de	4	26	1	4	2	17	1	0,0	105	0	0
38_dk	14	1	1	2	1	0	0	0,0	23	0	0
72_dk	5	1	0	1	1	0	0	0,0	19	0	0
39_cz	10	13	1	4	2	2	3	0,6	72	7	7
45_pl	82	24	4	11	3	12	4	1,1	172	6	6
47_ch	1	15	0	1	2	20	14	0,7	77	0	0
49_at	7	12	1	2	2	44	16	2,7	85	0	0
74_fi	6	1	1	1	0	3	1	5,4	8	0	0
75_fi	23	4	1	3	1	6	1	0,1	74	2	2
90_uk	19	19	1	4	2	0	0	0,0	162	3	3
91_uk	14	9	0	1	1	0	0	0,0	40	5	5
92_uk	28	20	1	3	2	3	6	0,2	158	2	2
93_uk	12	8	1	1	0	0	0	0,0	44	5	5
94_uk	14	3	0	1	1	2	5	3,5	22	1	1
95_uk	6	1	0	0	1	0	0	0,0	13	0	0
96_ie	14	4	0	0	2	1	2	0,0	43	0	0
79_no	1	1	0	0	0	0	5	11,8	6	0	0
7981_no	1	0	0	0	0	0	4	13,1	12	0	0
80_no	1	1	0	0	0	0	0	0,1	9	0	0
8081_no	1	0	0	0	0	0	2	7,8	3	0	0
81_no	1	0	0	0	0	0	5	12,2	12	0	0
82_no	2	2	0	0	0	0	2	3,3	29	0	0
8082_no	1	0	0	0	0	0	3	7,6	1	0	0
83_no	2	1	0	0	0	0	3	9,4	17	0	0
84a_no	1	0	0	0	0	0	2	10,7	4	0	0
84b_no	1	0	0	0	0	0	2	7,8	7	0	0
85_no	1	0	0	0	0	0	0	0,8	2	0	0
86a_se	2	1	0	0	0	0	4	11,7	2	0	0
86b_se	2	1	0	1	0	0	3	6,9	2	0	0
87a_se	3	1	1	1	0	0	3	5,1	6	0	0
87b_se	3	1	1	1	0	0	2	5,0	6	0	0
88_se	11	4	1	1	0	0	2	3,1	89	3	3
89_se	3	1	0	0	0	0	2	1,8	26	1	1
73_ee *)	37	3	1	3	1	6	3	0,2	62	1	0
57_si	0	2	0	1	0	9	0	0,0	15	1	1
59_ro *)	59	70	9	20	1	94	44	8,4	349	10	10
106_ns	22	0	0	0	0	0	0	0,0	0	0	0
107_ns	11	0	0	0	0	0	0	0,0	0	0	0
108_ns	2	0	0	0	0	0	0	0,0	0	0	0
109_ns	2	0	0	0	0	0	0	0,0	0	0	0
110_ns	16	0	0	0	0	0	0	0,0	0	0	0
111_ns	27	0	0	0	0	0	0	0,0	0	0	0
112_ns	19	0	0	0	0	0	0	0,0	0	0	0
113_ns	6	0	0	0	0	0	0	0,0	0	0	0
114_ns	3	0	0	0	0	0	0	0,0	0	0	0
115_ns	3	0	0	0	0	0	0	0,0	0	0	0
116_ns	3	0	0	0	0	0	0	0,0	0	0	0
TOTAL	875	732	50	140	73	365	256	207,2	4277	95	95

Some flexibility in the nuclear production were allowed in the analyses. Figure A1 shows the possible flexibility over a week and over a year.

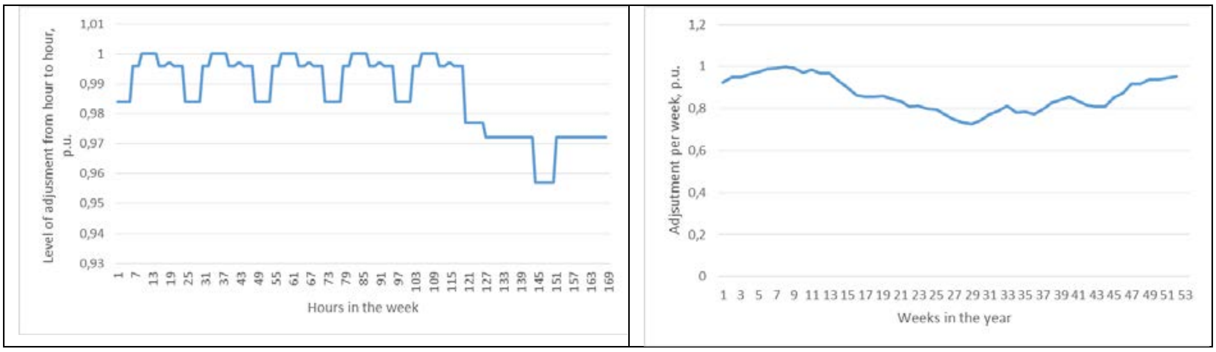

Figure A1 Adjustments of available nuclear capacities over the week (to the left) and the year (to the right) (own assumptions)

Table A2 shows assumptions about transmission capacities. Except for the capacities in the North Sea, they are from eHighway2050. The transmission capacities to the nodes in the North-Sea are scaled up to be “infinite”.

Table A2 Transmission capacities (see Figure 1) (from eHighway2050 High-RES scenario).

To-from	[MW]	To-from	[MW]	To-from	[MW]
04_es-25_fr	16900	36_de-47_ch	6000	8082_no-81_no	7000
52_it-25_fr	5800	36_de-49_at	2800	80_no-82_no	6300
25_fr-47_ch	9500	37_de-39_cz	2000	81_no-83_no	1095
25_fr-96_ie	5700	37_de-49_at	16000	82_no-83_no	1100
25_fr-90_uk	15000	38_dk-72_dk	600	82_no-88_se	2148
25_fr-28_be	7600	38_dk-79_no	1700	83_no-84a_no	1900
25_fr-35_de	7100	38_dk-88_se	740	84a_no-84b_no	1100
25_fr-36_de	1800	39_cz-45_pl	4100	83_no-87b_se	1000
28_be-29_lu	700	39_cz-59_ro	2700	84b_no-86a_se	700
28_be-30_nl	13500	39_cz-49_at	2100	84a_no-87a_se	250
28_be-33_de	6000	45_pl-73_ee	9000	86a_se-86b_se	8200
28_be-90_uk	5000	45_pl-59_ro	600	86b_se-87b_se	8200
29_lu-35_de	2900	47_ch-49_at	2400	87a_se-87b_se	16300
30_nl-31_de	1400	47_ch-52_it	8500	87b_se-88_se	16300
30_nl-33_de	7100	49_at-52_it	10300	88_se-89_se	13500
30_nl-38_dk	700	49_at-57_si	1600	89_se-45_pl	600
30_nl-79_no	14700	49_at-59_ro	1600	85_no-84b_no	9500
30_nl-90_uk	1000	52_it-57_si	3600	73_ee-75_fi	5000
31_de-32_de	6400	72_dk-89_se	1700	57_si-59_ro	4300
31_de-33_de	17330	74_fi-75_fi	3500	73_ee-88_se	700
31_de-35_de	6300	74_fi-85_no	50	59_ro-52_it	15000
31_de-36_de	7000	74_fi-86b_se	1800	106_ns-94_uk	100000
31_de-37_de	4000	75_fi-88_se	1350	107_ns-93_uk	100000
31_de-38_dk	3000	90_uk-91_uk	7600	108_ns-92_uk	100000
31_de-79_no	10400	91_uk-92_uk	5000	109_ns-90_uk	100000
31_de-89_se	5200	92_uk-90_uk	13000	110_ns-28_be	100000
31_de-34_de	9300	93_uk-92_uk	11900	111_ns-30_nl	100000
32_de-45_pl	3400	92_uk-96_ie	2500	112_ns-113_ns	100000
32_de-72_dk	600	94_uk-93_uk	10500	112_ns-31_de	100000
32_de-89_se	11000	95_uk-93_uk	500	112_ns-33_de	100000
33_de-35_de	19050	96_ie-95_uk	3100	113_ns-38_dk	100000
33_de-36_de	2000	79_no-80_no	5500	113_ns-30_nl	100000
34_de-35_de	7600	79_no-92_uk	5000	114_ns-72_dk	100000
34_de-37_de	18840	7981_no-93_uk	1400	114_ns-116_ns	100000
34_de-39_cz	1700	80_no-8081_no	1500	115_ns-79_no	100000
34_de-45_pl	11700	8081_no-81_no	0	116_ns-88_se	100000
35_de-36_de	7700	7981_no-81_no	13700	80_no-7981_no	900
35_de-37_de	6130	79_no-7981_no	13700	8081_no-82_no	2000
36_de-37_de	7500	82_no-8082_no	4800	8081_no-7981_no	7000

Table A3 shows the marginal prices per technology and for rationing of demand. Except for the nuclear marginal price, the prices are from eHighway2050.

Table A3 Marginal power price per technology/demand used in the simulations

Source of data	Type of production/demand	Price [Euro/MWh]
eHighway2050	Bio1	10
eHighway2050	Bio2	20
eHighway2050	Gas	203
Own assumtpion	Nuclear	0.05
eHighway2050	Rationing of demand	10000

Table A4. Increases in demand in Norway and Sweden in sensitivity case c

[TWh/y]	eHighway2050	30% increase
79_no	6.3	8.1
80_no	9.3	12.1
81_no	11.9	15.5
82_no	29.1	37.8
83_no	17.3	22.6
84a_no	4.3	5.6
84b_no	6.7	8.7
85_no	1.5	2.0
7981_no	11.5	15.0
8081_no	3.1	4.0
8082_no	1.0	1.3
Total Norway	102.0	132.6
86a_se	2.0	2.6
86b_se	2.0	2.6
87a_se	5.9	7.7
87b_se	5.9	7.7
88_se	89.5	116.3
89_se	26.3	34.2
Total Sweden	131.6	171.0

Table A5 shows the energy balances for the High-RES scenario with extra nuclear and with 11 GW increases of capacity in the Norwegian hydropower system.

Table A5 Energy balance High-RES scenario with extra nuclear and with 11 GW increase in Norwegian hydropower capacity. Output EMPS analyses

Region	Demand [TWh/y]	Export [TWh/y]	Import [TWh/y]	Wind [TWh/y]	PV [TWh/y]	Hydro [TWh/y]	Hydro w/reservoir [TWh/y]	Bio [TWh/y]	Gas [TWh/y]	Nuclear [TWh/y]	Surplus [TWh/y]	Rationing [TWh/y]	Price [Euro/MWh]
04_es	569.0	39.1	-72.9	130.2	240.8	35.5	63.3	80.9	1.3	30.3	-19.8	0.0	57.5
52_it	431.4	47.4	-142.1	75.6	147.4	18.8	55.0	51.6	0.7	0.0	-9.3	0.0	48.9
25_fr	649.4	272.0	-102.1	220.9	118.7	36.2	68.8	83.9	1.7	308.9	-16.7	0.0	50.0
28_be	121.3	25.9	-92.8	20.0	22.2	1.3	0.0	15.0	0.7	0.0	-2.9	0.0	57.1
29_lu	7.4	0.3	-5.2	0.9	1.0	0.7	0.0	0.0	0.1	0.0	0.0	0.0	57.1
30_nl	160.7	39.1	-137.4	28.6	19.9	0.5	0.0	12.1	0.6	7.1	-3.8	0.0	56.6
31_de	111.4	75.1	-108.4	57.3	12.5	0.8	0.7	11.9	0.4	0.0	-3.4	0.0	55.8
32_de	63.1	26.6	-27.1	47.7	8.7	0.0	0.0	13.2	0.3	0.0	-6.9	0.0	50.5
33_de	145.0	25.4	-132.4	21.4	9.4	0.4	0.7	10.3	1.1	0.0	-2.9	0.1	56.9
34_de	62.9	56.2	-69.6	22.5	11.5	0.2	6.0	13.8	0.1	0.0	-3.2	0.0	55.0
35_de	89.9	30.3	-90.4	9.5	9.5	0.1	0.7	13.0	0.1	0.0	-1.2	0.0	56.2
36_de	88.2	16.4	-73.2	2.5	10.6	3.9	5.9	10.5	0.1	0.0	-0.7	0.0	56.0
37_de	105.2	28.7	-78.9	4.8	24.0	12.1	0.7	15.7	0.3	0.0	-0.9	0.0	55.6
72_dk	19.4	5.4	-13.7	8.4	0.8	0.0	0.0	3.0	0.0	0.0	-0.9	0.0	50.5
38_dk	23.3	18.6	-8.3	31.8	1.2	0.0	0.0	6.6	0.1	0.0	-5.9	0.0	55.2
39_cz	71.8	49.1	-14.8	21.4	13.5	1.3	18.2	10.2	0.0	49.7	-8.0	0.0	35.7
45_pl	172.2	83.3	-32.6	137.7	23.5	7.7	0.7	30.0	0.2	40.5	-13.4	0.0	39.2
47_ch	77.3	39.7	-50.9	0.9	17.3	13.5	38.0	4.0	0.2	0.0	-6.8	0.0	52.3
49_at	84.8	70.9	-54.7	11.1	14.1	30.8	39.4	10.9	0.1	0.0	-4.2	0.0	53.7
74_fi	8.4	14.5	-3.4	11.7	1.0	2.0	4.8	1.9	0.0	0.0	-1.8	0.0	24.2
75_fi	74.2	21.7	-17.0	44.6	3.6	8.7	6.9	7.2	0.0	14.3	-5.9	0.0	30.1
90_uk	162.5	52.1	-152.3	23.4	16.4	0.0	0.0	11.2	0.4	21.4	-7.7	0.0	63.2
91_uk	39.5	25.3	-0.6	29.2	8.0	0.0	0.0	1.1	0.2	35.6	-9.9	0.0	62.6
92_uk	158.1	34.2	-92.3	60.3	17.1	1.5	0.3	11.0	0.4	14.3	-3.1	0.1	63.5
93_uk	43.9	44.5	-25.9	24.5	6.4	0.1	0.0	4.1	0.0	35.7	-7.7	0.0	61.3
94_uk	22.0	20.1	-2.8	35.0	2.7	1.2	4.6	2.8	0.1	7.1	-14.1	0.0	59.8
95_uk	13.2	3.7	-4.5	15.4	1.0	0.0	0.0	0.0	0.1	0.0	-4.0	0.0	63.3
96_ie	43.1	14.2	-27.7	32.1	3.1	0.7	0.0	0.7	0.4	0.0	-6.8	0.0	62.9
79_no	6.3	70.8	-59.9	3.3	0.5	0.0	14.3	1.1	0.0	0.0	-0.9	0.0	55.4
7981_no	11.5	29.2	-31.1	1.9	0.3	0.0	8.1	0.0	0.0	0.0	0.0	0.0	54.4
80_no	9.3	12.2	-18.4	1.7	0.6	0.0	0.2	1.1	0.0	0.0	0.0	0.0	54.4
8081_no	3.1	9.2	-2.0	1.6	0.0	0.0	8.8	0.0	0.0	0.0	-0.1	0.0	53.3
82_no	29.1	8.9	-23.9	2.9	1.3	0.0	10.3	0.0	0.0	0.0	0.0	0.0	53.4
8082_no	1.0	12.8	0.0	2.8	0.0	0.0	11.3	0.0	0.0	0.0	-0.3	0.0	52.3
81_no	11.9	18.7	-11.7	1.7	0.3	0.0	17.2	0.0	0.0	0.0	-0.1	0.0	53.3
83_no	17.3	16.4	-14.3	4.1	0.5	0.0	15.2	0.0	0.0	0.0	0.0	0.0	38.2
84a_no	4.3	13.2	-6.1	2.4	0.3	0.0	9.0	0.0	0.0	0.0	-0.2	0.0	16.3
84b_no	6.7	9.9	-7.3	2.6	0.3	0.0	6.7	0.0	0.0	0.0	-0.2	0.0	2.4
86a_se	2.0	20.2	-4.4	3.5	0.6	0.0	13.5	1.0	0.0	0.0	-0.7	0.0	25.5
86b_se	2.0	37.9	-24.6	3.9	0.6	0.0	11.2	0.4	0.0	0.0	-0.4	0.0	26.0
87a_se	5.9	15.3	-1.8	4.3	0.6	0.0	11.0	3.8	0.0	0.0	-0.3	0.0	47.2
87b_se	89.5	29.8	-65.8	17.0	3.8	0.0	9.8	3.0	0.0	21.4	-0.2	0.0	48.1
88_se	26.3	51.0	-56.6	7.0	1.2	0.0	5.3	1.4	0.0	7.1	-0.1	0.0	49.0
89_se	1.5	42.5	-41.8	2.5	0.2	0.0	1.7	0.0	0.0	0.0	-1.3	0.0	50.1
85_no	5.9	6.7	-0.2	3.9	0.6	0.0	9.5	0.0	0.0	0.0	-1.6	0.0	2.3
73_ee	14.9	25.9	-26.5	0.8	2.6	5.7	0.1	1.6	0.0	8.9	-4.7	0.0	38.5
57_si	61.5	29.6	-16.9	65.5	3.0	3.5	2.5	6.5	0.0	6.8	-11.9	0.0	27.1
59_ro	348.6	103.8	-21.8	101.0	67.4	65.0	87.3	53.7	0.0	69.2	-9.9	0.0	11.9
106_ns	0.0	65.6	-0.1	78.2	0.0	0.0	0.0	0.0	0.0	0.0	-12.7	0.0	62.0
107_ns	0.0	27.7	-0.1	39.1	0.0	0.0	0.0	0.0	0.0	0.0	-11.5	0.0	62.3
108_ns	0.0	3.1	-0.2	6.5	0.0	0.0	0.0	0.0	0.0	0.0	-3.6	0.0	60.1
109_ns	0.0	2.7	-0.2	6.5	0.0	0.0	0.0	0.0	0.0	0.0	-4.1	0.0	58.6
110_ns	0.0	7.5	-0.1	10.5	0.0	0.0	0.0	0.0	0.0	0.0	-3.1	0.0	56.0
111_ns	0.0	44.6	0.0	55.7	0.0	0.0	0.0	0.0	0.0	0.0	-11.1	0.0	55.4
112_ns	0.0	99.2	-12.5	95.3	0.0	0.0	0.0	0.0	0.0	0.0	-8.3	0.0	55.7
113_ns	0.0	58.3	-2.0	67.3	0.0	0.0	0.0	0.0	0.0	0.0	-10.9	0.0	55.4
114_ns	0.0	15.6	-0.8	22.4	0.0	0.0	0.0	0.0	0.0	0.0	-7.6	0.0	49.5
115_ns	0.0	8.4	0.0	10.5	0.0	0.0	0.0	0.0	0.0	0.0	-2.1	0.0	54.3
116_ns	0.0	13.7	-5.5	10.5	0.0	0.0	0.0	0.0	0.0	0.0	-2.2	0.0	48.7
TOTAL Europe	4277.0	2090.5	-2090.5	1766.6	850.3	252.2	567.6	510.2	9.9	678.3	-282.5	0.4	