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On the potential role of flexible Norwegian hydropower in managing challenging renewable energy variability events in Europe

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Abstract. Previous research has identified flexible Norwegian hydropower as one potential key resource for managing variations in wind and solar power in Northern Europe. There is, however, a need for further detailed examination of this potential role of Norwegian hydropower based on updated future scenarios and using the latest data and model tools available. We analyze potential power system impacts of expanding Norwegian hydropower flexibility and Norway-Europe transmission, considering renewable energy variability based on a simulation for the historical weather years 1991-2020. The simulations are performed using FanSi, a stochastic optimization model for analyzing large-scale power systems with significant shares of hydropower combined with high shares of wind/solar power. A year 2050 scenario for Europe from the integrated energy system model SCOPE SD is used as framework for our analysis with FanSi. Our results highlight how expanded hydropower and transmission can potentially reduce price spikes during periods of low wind/solar output, reduce wind/solar energy curtailment during periods of high wind/solar output; and reduce price differences between interconnected areas during periods of either low or high wind/solar output. We demonstrate that these effects are attributable to more dynamic operation and expanded operational ranges of hydropower and transmission in the simulations assuming expanded hydropower and transmission capacities. We acknowledge high fundamental uncertainty in modelling a future system for the year 2050.

1. Introduction

The variability of wind and solar energy resources poses challenges for their large-scale integration into the power grid. Such variability can lead to high volatility in electricity prices, making it difficult for consumers to manage costs and adversely affecting revenues for some power producers, or requiring policy or market changes to mitigate such problems. In situations where electricity supply exceeds demand, wind and solar energy production may need to be curtailed, resulting in lost opportunities for producer revenue and clean energy production (1,2).



Previous research has identified flexible Norwegian hydropower as one potential significant resource for managing variations in wind and solar power in Northern Europe (3–7). There is, however, a need for further analyses and assessments based on recent developments in power systems and updated future scenarios. It is also crucial to investigate potential contributions of Norwegian hydropower in managing challenging weather events related to wind and solar energy variability. This includes both events with simultaneous low outputs from wind and solar energy (energy shortage), and events with concurrent high outputs (energy surplus).

We analyze potential effects of Norwegian hydropower flexibility and Norway-Europe transmission expansion on energy shortage and energy surplus situations in Northern Europe. To do so, we use the power market model FanSi (8) to simulate the operation of the Northern European power system in the year 2050 for 30 historical weather years, with and without hydropower and transmission expansions. As the basis for our analysis with FanSi, we use a net zero emission scenario for Europe from the integrated energy system model SCOPE SD (9–11).

The assumed expansions to Norwegian hydropower comprise +11 GW generation and +5.2 GW pumping capacities, using existing reservoirs with substantial storage (7000 million m³ in upper reservoirs in total). The assumed upgrades in Norway-Europe transmission amount to +11 GW in total. Estimates of the effects of expanded hydropower and transmission are derived from comparisons of FanSi results with and without these expansions, with all other factors remaining constant. FanSi is well-equipped for this task because it offers a detailed description of Nordic hydropower systems and incorporates a stochastic approach to weather variability.

This article concentrates on FanSi results for individual periods characterized by either energy surplus or shortage. The FanSi simulations comprise 30 historical weather years with three-hourly time resolution. Results from the simulations include power prices, transmission flows, and renewable energy curtailment during challenging renewable energy variability events. They provide insights into potential Northern European system benefits of upgraded Norwegian hydropower and transmission in future scenarios for the year 2050.

2. Data and methods

We employ the stochastic optimization model FanSi to analyze the operation of the Northern European power system in a year 2050 scenario, with and without upgrades in Norwegian hydropower and Norway-Europe transmission. The FanSi model dataset represents the power system in Northern Europe with varying levels of detail, as illustrated in Figure 1. The hydropower systems in Norway are modelled in detail, including thorough representations of topology, waterways, reservoirs, power plants, and environmental constraints. The system is divided into 40 separate price areas (excluding offshore areas), of which eleven are in Norway, six in Sweden,

six in Germany and three in the United Kingdom. We elaborate on the data and methods in the following subsections.



Figure 1. Schematic representation of the power system modeled with FanSi. The intensity of blue shading indicates level of detail in the representation of power demand and supply, with darker shades representing more detailed modeling. Yellow circles represent offshore wind areas. Key model areas for this study are labeled with names and numbers.

2.1 Norwegian hydropower expansion

A previous study estimated that upgrading hydroelectric power plants at existing reservoirs in southern Norway could boost production capacity by 11-20 GW and pumping capacity by 5 GW. The environmental impacts of these extension are expected to be relatively low since the construction would involve new tunnels connecting to existing reservoirs rather than creating new reservoirs, and discharge flowing into large reservoirs or fjords (12).

For the modeling of expanded Norwegian hydropower in this study, we adopt estimates from the research centre CEDREN (13) that would give 11 GW additional hydropower production capacity and 5.2 GW pumping capacity in total by using existing reservoirs in southern Norway (12). The individual projects that make up the expansions are detailed in Table 1.

Table 1. Assumed expansions to hydropower generation and pumping installations [12].

Power plant	Capacity (MW)	Upper reservoir	Lower reservoir	FanSi area
Tonstad	1400 *	Nesjen	Sirdalsvatn	SOUTH
Holen	700 *	Urarvatn	Botsvatn	SOUTH
Kvilldal	1400 *	Blåsjø	Suldalsvatn	WESTMID
Tinnsjø	1000 *	Møsvatn	Tinnsjø	CENTRAL
Tysso	700 *	Langevatn	Ringedalsvatn	WEST
Jøsenfjord	1400	Blåsjø	Jøsenfjord	WEST
Lysebotn	1400	Lyngsvatn	Lysefjorden	SOUTH
Mauranger	400	Juklavatn	Hardangerfjord	WESTMID
Oksla	700	Ringedalsvatn	Hardangerfjord	WEST
Sy-Sima	700	Sysenvatn	Hardangerfjord	WESTMID
Aurland	700	Viddalsvatn	Aurlandsfjord	WESTMID
Tyin	700	Tyin	Årdalsvatn	WESTMID

Capacity numbers labelled '*' denote both generation and pumping capacity expansions; otherwise numbers denote generation capacity only. Generation capacities amount to 11.2 GW and pumping capacities 5.2 GW. For FanSi area names, compare to areas labelled 'NO' in Figure 1.

2.2 Norway-Europe transmission expansion

Table 2 provides an overview of transmission capacities between Norway and other countries assumed for model runs with and without transmission expansion, respectively. The transmission expansions encompass interconnectors between Norway and four neighboring countries: Denmark, Germany, the Netherlands, and the United Kingdom.

The baseline capacity figures given in Table 2 align with current actual transmission capacities, except for the interconnection between NO-SOUTH and DK-WEST (which is currently 1632 MW (14) but may be lower in the future if interconnections Skagerrak 1 and 2 are phased out (15)), and between NO-VEST and UK-MID (which currently are not connected). Substantial expansions (11 GW in total) are assumed in the expanded case to serve the purpose of this study.

2.3 Power system data

This subsection describes the scenario dataset beyond the hydropower and transmission expansions already introduced in the previous two subsections.

A net zero CO₂ emission scenario for Europe for the year 2050 from the integrated energy system and capacity expansion model SCOPE SD (9–11,16,17) provides a framework for our modeling with FanSi. SCOPE SD is a bottom-up techno-economic partial equilibrium model. It develops coherent long-term energy system scenarios for Europe by minimizing the investment

Table 2. Assumed Norway-Europe transmission capacities.

Area in Norway	Area abroad	Capacity baseline (MW)	Capacity expanded (MW)
NO-SOUTH	DK-WEST	1132	2532
NO-SOUTH	GE-NORTH	1400	7000
NO-SOUTH	NETHERLANDS	700	2100
NO-VESTMID	UK-NORTH	1400	2800
NO-VEST	UK-MID	1400	2800

Assumed capacities are the same in both directions. Increases in transmission capacity from baseline to expanded amount to 11.2 GW in total. For FanSi area names, compare to areas depicted in Figure 1.

and operation costs of generation, storage and cross-sectoral technologies. It covers the power system and technologies at the sectoral interfaces with buildings, industry, and transport. Each European country is represented by one node. All units, their most important parameters, and interactions are modelled at hourly resolution. Specifically, we use the SCOPE SD “baseline_ref” scenario from ref. (18), systematically feeding the SCOPE scenario results to FanSi (i.e., “soft-linking” of models (19)).

The data transfer from SCOPE SD to FanSi includes SCOPE SD variables representing installed generation capacities (onshore wind, offshore wind, solar, hydro, nuclear, hydrogen, other), demand (heating, cooling, electric vehicle controlled, electric vehicle uncontrolled, other industry and transport), energy storage (pumped storage hydropower, hydrogen, Li-ion batteries), average capacity factors for onshore and offshore wind, transmission and various plant efficiencies by country. Thanks to the optimized power system investments from the SCOPE SD modeling, we obtain a coherent dataset of installed capacities for the year 2050 for use in the operational-only optimization model FanSi.

Figure 2 presents an overview of the power generation mix in selected countries based on the SCOPE SD “baseline_ref” scenario (18) which forms the basis for the analysis with FanSi in this study. The combined share of wind and solar capacity to total capacity is 28% for Norway and 40-48% for other countries. There are no fossil fuel-based power plants, but flexible hydrogen-fired power capacity constitutes 5-7% of total capacity in the Netherlands, United Kingdom and Germany. The hydrogen is assumed to be produced from electricity using electrolysis; and this is integrated into the modeling.

Table 3 presents the overall production, demand and net power balance for selected countries under the SCOPE SD “baseline_ref” scenario (18). In this scenario, Norway’s power production and demand in the year 2050 amount to 212 and 174 TWh yr⁻¹, respectively. Thus, Norway has a net export of 38 TWh yr⁻¹. In comparison, NVE’s base scenario estimates a production of 207 and demand of 191 TWh yr⁻¹ for the year 2040 (20). One factor contributing to the relatively low demand for Norway in the SCOPE SD “baseline_ref” scenario is the allocation of hydrogen production from electrolysis to other countries (with this hydrogen production being partially supplied by electricity imported from Norway). Conversely, the NVE scenario assumes hydrogen production within Norway.

Table 3. Annual power production, demand and balance by country.

Country	Production (TWh yr ⁻¹)	Demand (TWh yr ⁻¹)	Balance (TWh yr ⁻¹)
Norway	212	174	38
Sweden	264	267	-3
Denmark	136	92	43
Finland	166	167	-1
The Netherlands	251	248	3
United Kingdom	706	736	-30
Germany	887	923	-36

Based on SCOPE SD "baseline_ref" scenario for the year 2050 [18].

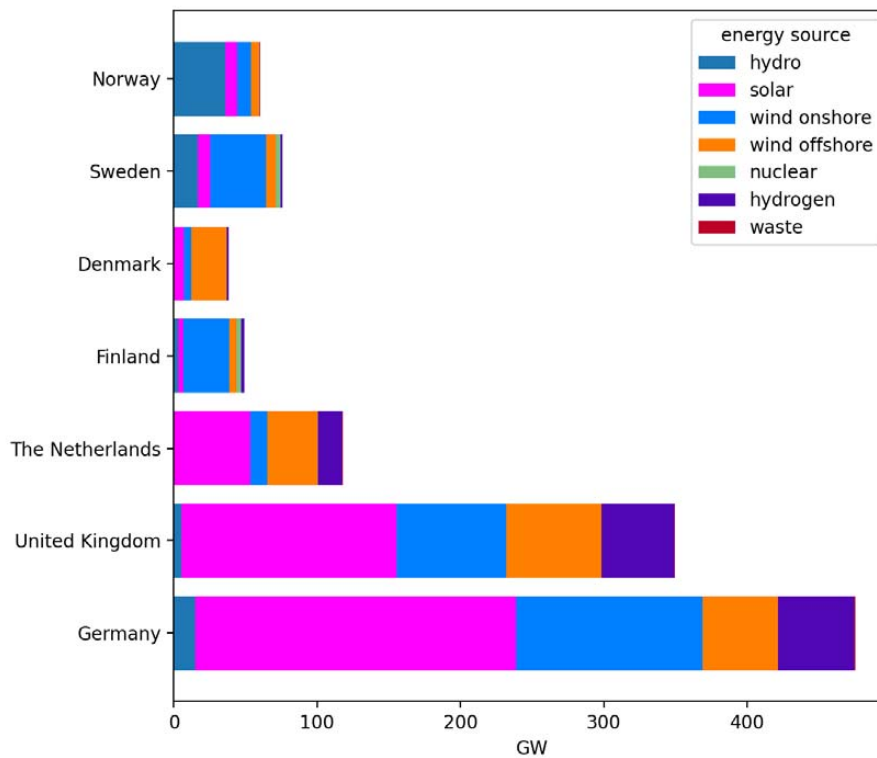


Figure 2. Power generation capacities by country and energy source. Based on SCOPE SD results for the year 2050 and scenario "baseline_ref" [18]. Note that the Norwegian hydropower expansions introduced previously in 2.1 Norwegian hydropower expansion are added in the FanSi analysis, but not implemented in the SCOPE SD "baseline_ref" scenario.

Motivated by the prominence of hydrogen (and flexibility from hydrogen) in SCOPE SD (18) as well as in other analyses (e.g., refs. (15,21,22)), we introduce simplified representations of hydrogen production from electrolysis, hydrogen storage, hydrogen import and hydrogen markets in the FanSi datasets. The hydrogen import price is set to 85 EUR MWh⁻¹, as in SCOPE SD (18). These representations of hydrogen storage, markets and import introduce substantial flexibility and allow us to capture power-hydrogen market interactions in the system modeled in

FanSi. Other key sources of flexibility in the system are pumped storage hydro, stationary batteries (82 GW and 490 GWh in total across the seven example countries represented in Figure 2), flexible demand, and hydrogen-fired power plants. For further details on the SCOPE SD modeling, see ref. (18).

Beyond the data obtained from SCOPE SD model results, we incorporate detailed representations of hydropower in Norway based on data provided by The Norwegian Water Resources and Energy Directorate (NVE) for the year 2021; this includes representations of topology, reservoirs, rivers, environmental constraints, and power plants. Guided by information from NVE (23,24), we modify hydropower capacities to account for increases expected by the year 2050. Detailed descriptions for hydropower in Sweden and aggregated descriptions for other hydropower are based on previous studies (25,26).

We utilize estimated time series data for historical weather years 1991-2020 for wind and solar power in each FanSi model area (27). These estimates are derived from meteorological ERA5 reanalysis data (28), which are defined at an hourly time resolution and aggregated to 3-hourly resolution for the analysis with FanSi in this study.

2.4 Power system model FanSi

FanSi is a fundamental long-term market model for analyzing large-scale power systems with significant shares of hydropower combined with high shares of wind and solar power (8). Dynamics are introduced through water reservoirs and other energy storage that connect decisions across time periods (water/energy stored now can be utilized for future power generation, whereas water/energy used now is unavailable for future generation).

The model optimizes scheduling decisions in the hydro-thermal system by solving a sequence of stochastic optimization problems over a moving time window. Each problem is broken down into two stages: The first-stage problem is solved deterministically with known weather conditions at a high temporal resolution (three hours in this study); the second stage is solved using ‘scenarios’, which here refers to historical weather years, to represent future uncertainty related to weather at a coarser temporal resolution (one week). The second stage spans a time horizon of 52 weeks in this study. To represent the system state at the end of this horizon, we use water values calculated by the EMPS model (29), a stochastic optimization model based on hydropower aggregation in combination with heuristics to determine individual hydropower plant production. EMPS is extensively used by actors in the Nordic power system.

Compared to the EMPS model, FanSi provides a more sophisticated optimization of complex watercourses and better represents short-term flexibility such as that from pumped hydro storage. This advantage stems from FanSi’s use of formal mathematical optimization to determine the dispatch of individual hydropower plants, unlike EMPS which relies on analyst inputs or heuristics. Meanwhile, the increased sophistication makes FanSi more computationally demanding than EMPS. Around 1400 hydropower modules are defined in the dataset used for this study. FanSi is maintained by SINTEF Energy Research in Norway. For more information on methods employed in FanSi, we refer to the model documentation (8,30).

3. Results

We will present selected results from two FanSi model runs (or scenarios). We will refer to these scenarios as ‘baseline’ and ‘expanded’, respectively. The ‘expanded’ scenario includes the expansions in Norwegian hydropower and transmission as outlined in *2.1 Norwegian hydropower expansion* and *2.2 Norway-Europe transmission expansion*, respectively. The scenario ‘baseline’

excludes these expansions. All other factors are kept equal in ‘baseline’ and ‘expanded’ based on the general power system data introduced in 2.3 *Power system data*. The results comprise two examples of occurrences of periodical energy shortage (high prices) and two examples of periodical energy surplus (low prices). The examples serve as illustrations of effects that we observe in the simulation results and indicate potential effects of flexible hydropower and transmission expansion in future power systems.

3.1 *Periods with energy shortage (high prices)*

Figure 3 shows an example of periodical energy shortage where the given expansions to flexible Norwegian hydropower and transmission eliminates price spikes in the simulations. This example is obtained from the FanSi simulations for week 15 (approximately the second week of April) in the year 1996. Before considering the specific results for week 15, it is relevant to note that this week follows a prolonged period of relatively low reservoir inflow and consequently low total reservoir fillings in the area NO-SOUTH of southern Norway (Figure 3a). This low reservoir state in NO-SOUTH coincides with particularly low wind power generation in Northern Europe during week 15, including offshore wind power for the Danish area DK-WEST (Figure 3b).

Despite the lower hydropower reservoir levels in week 15, the additional hydropower generation and pumping capacities in NO-SOUTH in the ‘expanded’ scenario allows for an expanded operational range and more dynamic flexibility (Figure 3c). The ability to operate hydropower in NO-SOUTH (and in NO-CENTRAL and other adjacent areas, though these are not shown in Figure 3) more flexibly is also augmented by the increased transmission capacity to neighboring countries, including to DK-WEST (Figure 3d). As a result of these enhancements in hydropower and transmission, power price volatility is reduced and spikes and prices in DK-WEST are eliminated in ‘expanded’ (Figure 3e). Meanwhile, price volatility in NO-SOUTH increases in the ‘expanded’ scenario, but only in a downward direction (Figure 3f).

Figure 4 presents a second example where enhanced flexible Norwegian hydropower and transmission capabilities significantly reduce Northern European price spikes, according to the simulations. This example is based on simulation results for weeks 6 and 7 (approximately in the first half of February). This period is characterized by particularly low power generation in Northern Europe in certain intervals, including offshore wind power in the UK-MID region, which is low or virtually zero for parts of the two-week period (Figure 4a). Like the first example (Figure 3), the expanded hydropower and transmission capacities (Figure 4b-d) result in reduction in power price spikes in a Northern European region, in this case UK-MID (Figure 4e). However, unlike in the first example, power price volatility in the Norwegian area increases introducing a new peak in price in NO-WEST in the ‘expanded’ scenario (Figure 4f).

A closer examination of Figure 4 reveals additional complexities. One key observation is that although the offshore wind output is very low in certain intervals and low overall over the two-week period, there are also time steps with high wind power (Figure 4a). During these high-wind periods, there are noticeable increases in NO-WEST import from UK-MID in ‘expanded’ (Figure 4b). Another layer of complexity arises from influences of the solar diurnal cycle on the results: For instance, the incidents of maximum import (2800 MW) to NO-WEST in ‘expanded’ (Figure 4b) can be attributed to relatively high UK solar power at mid-day leading to power transfers to Norway. Diurnal patterns stemming from solar variations are also visible in results for hydropower (Figure 4c-d)¹.

¹ These impacts occur even though February’s solar output levels are considerably lower compared to those in the summer months.

3.2 Periods with energy surplus (low prices)

Figure 5 provides an example of periodical energy surplus where the expansions to Norwegian hydropower and transmission reduce renewable energy curtailment. This example is based on simulation results for weeks 1-2 of 1998. Solar energy generation is relatively low during this period due to winter, but wind power in Northern Europe is high, including offshore wind power for GE-NORTH, Germany (Figure 5a). The simulations show that with expanded Norwegian pumped storage hydro and Norway-Europe transmission capacities, there is a significant increase in import of electricity to Norway (Figure 5b) and use of electricity to pump water from low to high reservoirs in Norway (Figure 5c; negative numbers indicate that pumping exceeds generation in the NO-SOUTH area). Consequently, the 'expanded' scenario exhibits a reduction in curtailed renewable power (Figure 5c) and results in more balanced power prices between the NO-SOUTH and GE-NORTH markets (Figure 5d-e). The simulations show no curtailment in NO-SOUTH in weeks 1-2 of 1998.

Figure 6 illustrates results from the simulation of week 35 (approximately last week of August) of 2012. This week includes hours at the beginning and end of the week where offshore and onshore wind, and solar outputs are relatively low, as well as a period in the middle of the week where outputs are high (Figure 6a-b). In the 'expanded' scenario compared to the 'baseline' scenario, there is a significant increase in the power transmitted from DK-WEST to NO-SOUTH during the hours with high wind and solar outputs in DK-WEST (Figure 6c)².

Still comparing the 'expanded' and 'baseline' scenarios, we observe that significant drops in aggregate hydropower production in NO-SOUTH and NO-CENTRAL roughly coincide with high wind and solar power generation in DK-WEST. Conversely, significant increases in NO-SOUTH and NO-CENTRAL hydropower production coincide with low wind and solar power outputs in DK-WEST (Figure 6c-e). Because of these adaptations, renewable energy curtailment decreases in 'expanded' (Figure 6f), number of hours with power prices equal to zero decreases, and power prices become more balanced between NO-SOUTH and DK-WEST (Figure 6g-h).

² We observe similar results for wind and solar outputs in GE-NORTH of Germany as for DK-WEST, and for transmission from GE-NORTH to NO-SOUTH as for transmission from DK-WEST to NO-SOUTH.

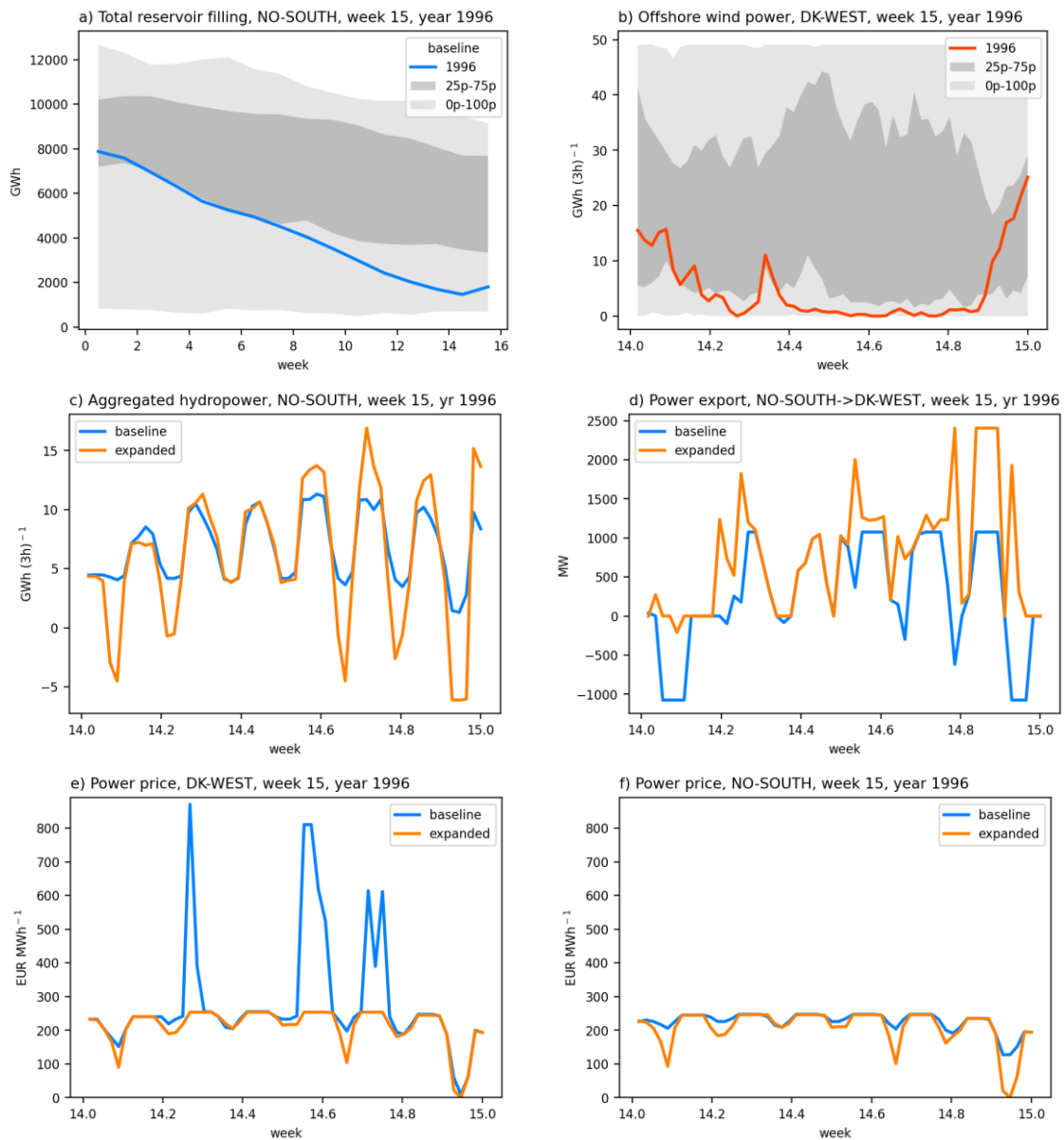


Figure 3. Example FanSi results illustrating a periodical energy shortage. Results are based on simulations for week 15 in 1996. Panel a shows aggregated hydropower reservoir fillings for NO-SOUTH in scenario 'baseline' in weeks 1-15 of 1996 as background information. Panel b shows offshore wind power generation for DK-WEST for week 15 (these data are model inputs and thus the same in 'baseline' and 'expanded'). In panels a-b, "0P-100P" denotes 0-100 and "25P-75P" 25-75 percentiles range across 30 simulated weather years. Panels c-f compare 'baseline' and 'expanded' scenario results for week 15 in 1996 specifically for aggregated hydropower production in NO-SOUTH, power export from NO-SOUTH to DK-WEST (negative values mean import to NO-SOUTH), and power price in DK-WEST and NO-SOUTH, respectively. See Figure 1 for definitions of areas.



Figure 4. Example FanSi results illustrating a periodical energy shortage based on simulations for weeks 6-7 in 2010. Panel a shows offshore wind power for UK-MID (these data are model inputs and thus the same in 'baseline' and 'expanded'). "0P-100P" denotes 0-100 and "25P-75P" 25-75 percentiles range across 30 simulated weather years. Panels b-f compare 'baseline' and 'expanded' scenario results for power export from NO-WEST to UK-MID (negative values mean import to NO-WEST), aggregated hydropower in NO-WEST, and power price in UK-MID and NO-WEST, respectively. See Figure 1 for definitions of areas.

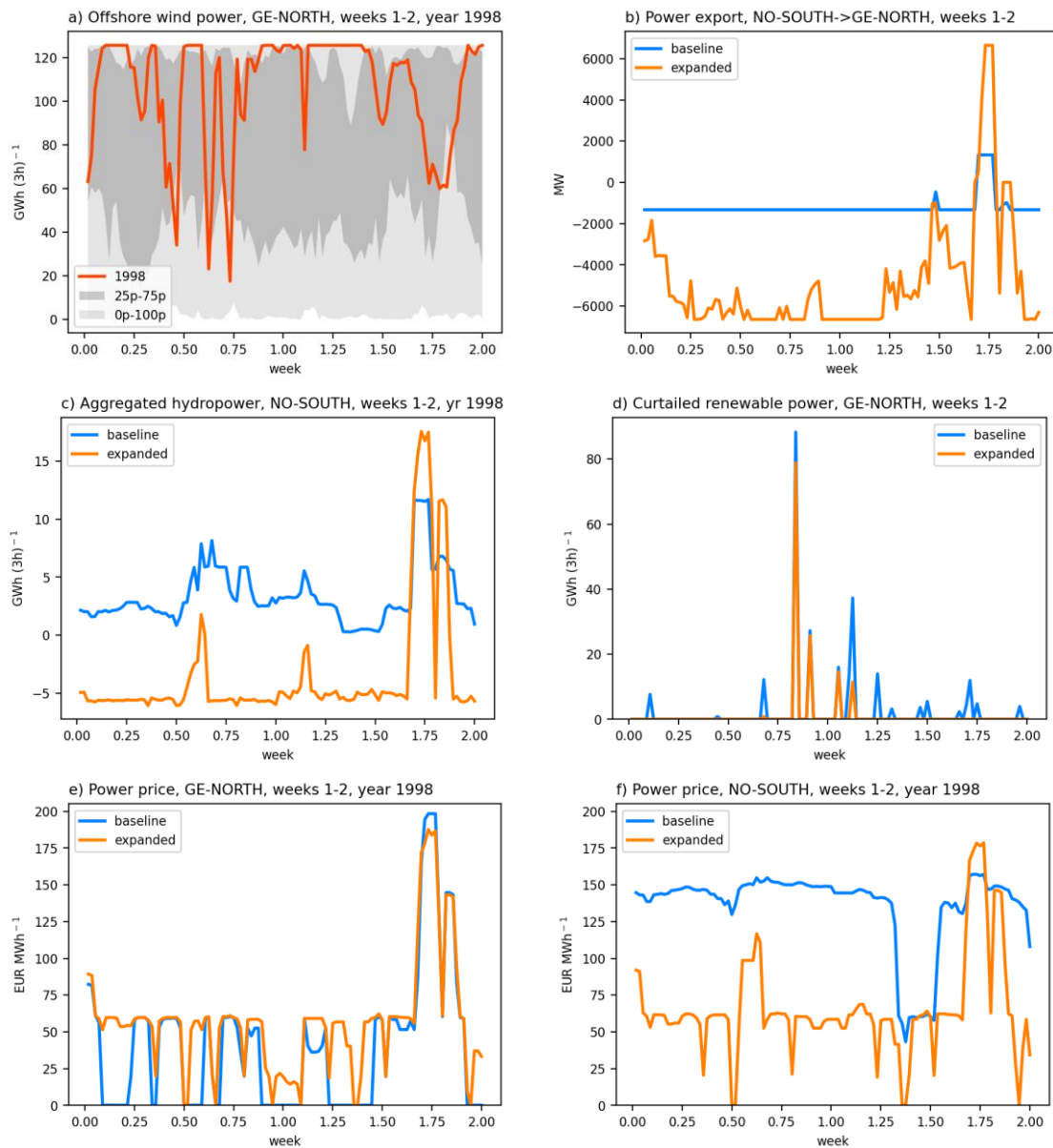


Figure 5. Example FanSi results illustrating a periodical energy surplus. Results are based on simulations for weeks 1-2 in 1998. Panel a shows offshore wind power generation before curtailment for GE-NORTH for weeks 1-2 (these data are model inputs and thus the same in 'baseline' and 'expanded'). "0P-100P" denotes 0-100 and "25P-75P" 25-75 percentiles range across 30 simulated weather years. Panels b-f compare 'baseline' and 'expanded' scenario results for weeks 1-2 in 1998 for power export from NO-SOUTH to GE-NORTH (negative values mean import to NO-SOUTH), curtailed renewable power for GE-NORTH, aggregated hydropower generation or pumping in NO-SOUTH, and power price in GE-NORTH and NO-SOUTH, respectively. See Figure 1 for definitions of areas.

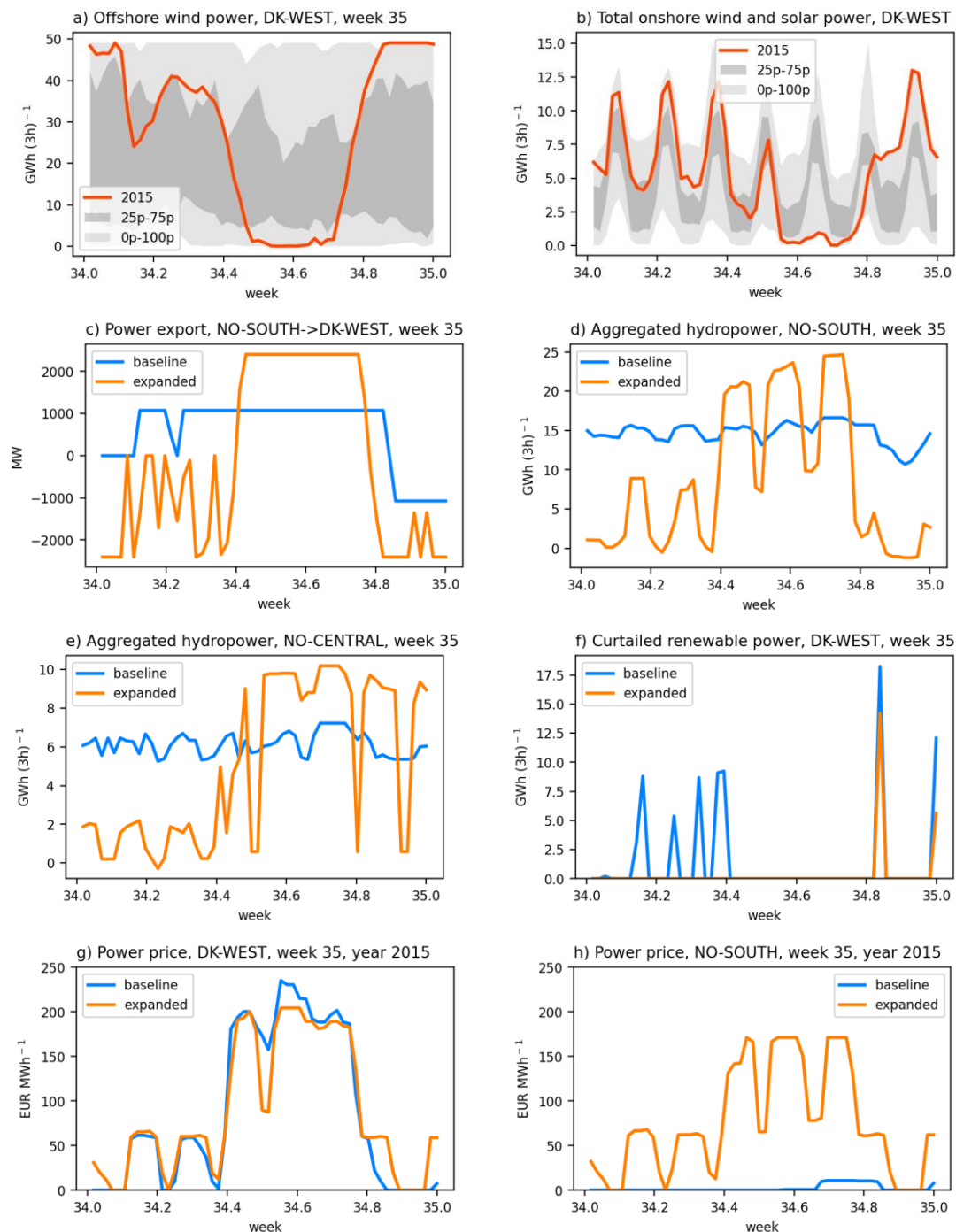


Figure 6. Example FanSi results illustrating a periodical energy surplus. Results are based on simulations for week 35 in 2015. Panel a shows offshore wind power generation before curtailment and panel b combined onshore wind and solar generation before curtailment for DK-WEST for week 35 (these data are model inputs and thus the same in 'baseline' and 'expanded'). "0P-100P" denotes 0-100 and "25P-75P" 25-75 percentiles range across 30 simulated weather years. Panels c-h compare 'baseline' and 'expanded' scenario results for week 35 in 2012 for power export from NO-SOUTH to DK-WEST, aggregated hydropower production in NO-SOUTH, aggregated hydropower production in NO-CENTRAL, curtailed renewable power for DK-WEST, and power price in GE-NORTH and NO-SOUTH, respectively. See Figure 1 for definitions of areas.

4. Discussion and conclusions

Reservoir-based hydropower is a dispatchable renewable energy technology. It can provide flexibility on short and long timescales, and thus help to accommodate rapidly growing shares of variable wind and solar power into power grids. In this study, we have employed the stochastic optimization model FanSi to examine potential power system impacts of expanded Norwegian hydropower flexibility and Norway-Europe transmission, providing examples of specific instances of challenging renewable energy variability in Northern Europe from simulations spanning 30 weather years.

Our results illuminate ways in which expanded hydropower and transmission can potentially: i) Reduce price spikes in periods with low output from wind/solar; ii) reduce wind/solar energy curtailment in periods with high output from wind/solar; and iii) reduce price differences between interconnected areas in instances with either low or high wind/solar output. We demonstrate that these effects are attributable to more dynamic operation and expanded operational ranges of hydropower and transmission in the simulations assuming expanded hydropower and transmission.

There is high fundamental uncertainty involved in modeling future systems for the year 2050. Specific uncertainties exist in various parts of our analysis. While it is a strength that we have implemented future sources of flexibility such as stationary batteries, hydrogen storage and flexible demand, we need to make assumptions regarding their detailed characteristics, and these have obvious high uncertainty in a year 2050 time horizon. Such alternative sources of flexibility can interact (potentially supplement or provide overlapping services) with flexibility from hydropower (31–33), and thus potentially influence our results.

Uncertainty also stems from the assumptions made on transmission grid configurations and capacities, both between countries and domestically within countries. The wide-area transmission represented in FanSi also offers a kind of flexibility as it allows for redistributions of electricity through the power grid (34–36). It is an advantage of our study that we model several areas per country (for Norway, Sweden, Denmark, United Kingdom and Germany), because it allows for considering internal transmission constraints. At the same time, the assumptions underlying this modeling are uncertain. Another, related point is that we assume each offshore wind farm area to have one radial connection to one onshore area, disregarding more sophisticated designs with multiple wind farms interconnected through a network of offshore substations and connected to potentially several countries (37,38). Finally, our analysis does not cover effects of future climate change on weather-dependent renewables, heating or cooling.

Future planned work includes comprehensive assessment of price and curtailment effects for various countries in Northern Europe. We also plan to examine effects on achieved prices for hydropower and other power producers, and effects on socioeconomic surplus, including potential redistributions between countries or between producers and consumers.

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