Report

Power system impacts of new environmental constraints for hydropower in Norway

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SUMMARY
The research project "New environmental constraints – consequences for the power system" aimed to provide a thorough understanding of the effects of new hydropower environmental constraints on the power system. The project employed three power system models, FanSi, Primod and EMPS, to analyse the power systems for the year 2030 under varying assumptions. Results and insights into the effects of environmental restrictions were obtained by comparing results from model runs with and without restrictions. Variables quantified by the models included power prices, power balances and exchanges between regions, power production patterns, flooding, availability of spinning reserve capacity and socioeconomic surplus.

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1 Introduction

Hydropower is a cornerstone of Norway's electricity system. It utilizes well-established technologies and renewable energy resources, and significantly contributes to the large-scale provision of electricity. Hydropower reservoirs in addition provide flexibility on short and long timescales, making hydropower a crucial enabler of rapidly growing shares of variable wind and solar power in electricity supply.

The EU Water Framework Directive, implemented in Norway through the Norwegian Water Regulation, initiated a process and framework for environmental safeguarding of water bodies and rivers. Following the directive, many concessions for Norwegian hydropower have recently undergone revision or are presently undergoing revision. These revisions lead to more stringent constraints, potentially yielding increased power loss and reduced production flexibility.

Assessing the system-wide impacts of the environmental restrictions is complex. The complexity emanates from the large number of revised concessions, the interplay of adaptations within connected rivers, reservoirs and power plants, and market adjustments. To address the task of evaluating system-wide effects, power system models both containing detailed representations of hydropower and being capable of simulating the operation of entire power systems are needed.

The research project "New environmental constraints – consequences for the power system" [1] aims to provide a thorough understanding of the effects of new hydropower environmental constraints on the power system. We employ three power system models, FanSi, Primod and EMPS, to analyze power systems for the year 2030 under varying assumptions. Results and insights into the effects of environmental restrictions are then obtained by comparing results from model runs with and without restrictions. Variables quantified by the models include power prices, power balances and exchanges between regions, power production patterns, flooding and socioeconomic surplus. An additional aim of the project is to apply, validate and advance FanSi and Primod that are prototype models. We will refer to the project using the abbreviated name SumEffekt.

This report presents the data and findings from the power system analyses undertaken within the project. It is accompanied by another project report presenting a summary of project findings in Norwegian.

2 Power system models

The primary power system models utilized are FanSi and Primod. In addition, the EMPS model is used as a supplement to FanSi. FanSi is a prototype fundamental long-term market model that we use for analyzing hydro-thermal electricity markets. Primod is a prototype fundamental short-term model for multi-market power system analyses. EMPS has a long history of successful applications. It is functionally equivalent to FanSi in terms of types of results produced but employs a different mathematical methodology.

All three models optimize the operation of the power system by maximizing socioeconomic surplus. While their scope encompasses the broader power system, they hold particularly detailed descriptions of the hydropower systems in the Nordic region. This includes comprehensive information about topology, waterways, reservoirs, environmental restrictions, and hydropower plants.

The main inputs to the model include costs and capacities of generation and transmission, electricity demand and information about historical climate variables like temperatures, hydro inflow, wind, solar radiation, typically with hourly resolution. The output from the model includes among other things power balances and (spot) power prices. To include the impact of weather variations and uncertainty, 35 historical weather years, 1981-2015, are analyzed. This set of 35 historical years gives a reasonable and

[1] In Norwegian: "Nye miljørestriksjoner – samlet innvirkning på kraftsystem".

sufficient representation of historical variability related to weather but note that our analyses will not cover specific weather events that have occurred after 2015 or the effects of climate change after 2015.

The geographical scope and division into individual areas are shared by all three models and are described next in Section 2.1. Then, Sections 2.2-2.4 describe each of the models in more detail.

2.1 Geographical scope and resolution

The model datasets represent the power system in North-Western Europe with varying level of detail as roughly illustrated by Figure 1. The descriptions of the hydropower systems in Norway are especially detailed, including detailed representations of topology, waterways, reservoirs, environmental restrictions, and power plants. In other respects, the most detailed descriptions are of the Nordic region and connected countries. These countries are divided into one or several price areas: Norway: 11 areas, Sweden: 6 areas, Denmark: 2 areas, Finland: 1 area, Germany: 7 areas, Netherlands: 1 area, Belgium: 1 area and Great Britain: 3 areas. A simple representation of demand and supply aggregated by technology is included for France, Poland and the Baltic region. In addition, exchange to the Czech Republic, Austria and Switzerland is modelled in a simplified way using fixed time series of energy exported from each country.

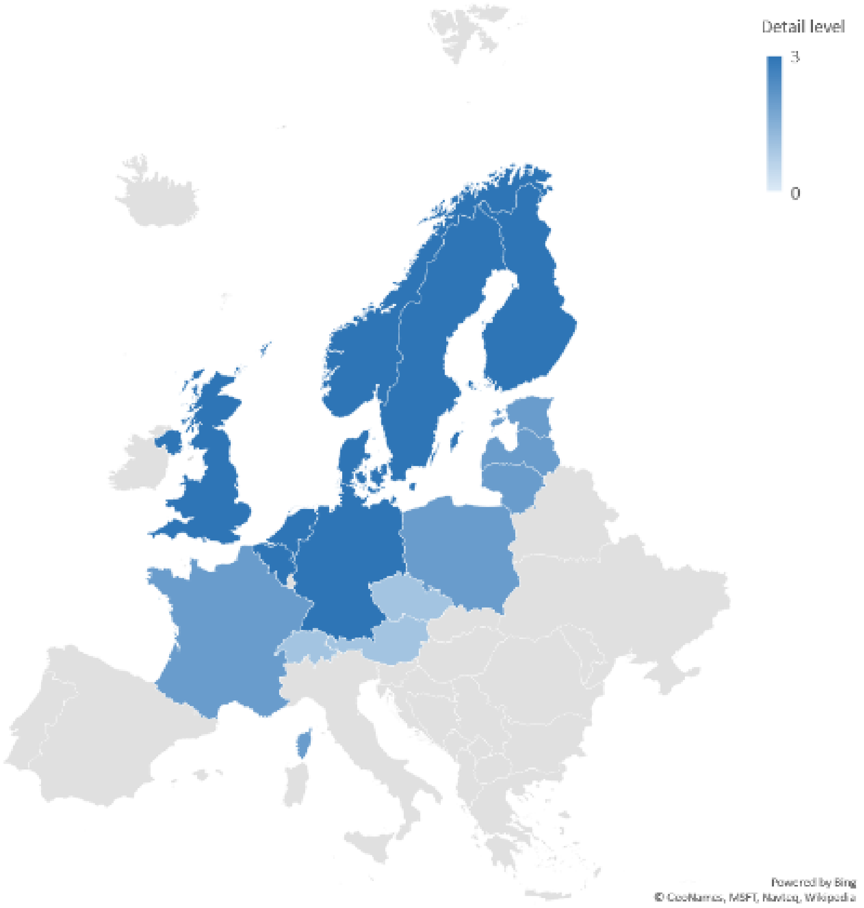

Figure 1 Countries included in the model are marked in blue. The darker blue, the more details are included in the modelling of demand and supply in the country. Figure is taken from Schäffer and Graabak (2018).

Besides the onshore areas covered in Figure 1, several offshore areas are also connected to include offshore wind. In total, the scenario consists of 57 areas, 38 onshore and 19 offshore.

When presenting results later in this report, we will sometimes aggregate results for the eleven model areas into Nord Pool bidding areas. Table 1 shows assumed correspondences between model areas in the Nordic region and the current Nord Pool bidding areas.

Table 1 Assumed correspondences between modelled Nordic areas and Nord Pool bidding areas.

Nord Pool bidding area	Model areas
NO1	Ostland
NO2	Sorost, Telemark, Sorland, Vestsyd
NO3	Norgemidt
NO4	Helgeland, Troms, Finmark
NO5	Hallingdal, Vestmidt
SE1	Sver-on1
SE2	Sver-on2, Sver-nn1, Sver-nn2
SE3	Sver-Midt
SE4	Sver-Syd
DK1	Danm-Vest
DK2	Danm-Ost
FI	Finland

2.2 FanSi

FanSi is a prototype model developed by SINTEF Energy Research as part of the project SOVN (Helseth et al. 2017). FanSi is a fundamental power market model encompassing detailed treatment of hydropower systems within the Nordic nations. It optimizes the operation of the power system by maximizing socioeconomic surplus. Dynamics are introduced as water reservoirs link decisions across different times (water stored can be used to generate power later, and conversely, water used for production is not available for the same production later).

Being designed as a simulator, FanSi operates by simulating each week for a specific historical 'weather year' in sequence by solving a two-stage stochastic optimization problem and using a rolling-horizon approach. Variabilities and uncertainties stemming from weather factors – including hydropower inflow, wind and temperature – are treated stochastically (Helseth et al. 2018).

We use FanSi as the primary long-term market model because FanSi, unlike EMPS, calculates water values per reservoir and optimizes the utilization of complex watercourses within the week. This is expected to be a particular strength when analyzing power systems with substantial inputs from variable wind and solar production and with potentially considerable fluctuations in power prices within the week. Also in contrast to EMPS, FanSi utilizes formal mathematical optimization to determine reservoir operation strategies without inputs from the analyst or use of heuristics.

Figure 2 shows a schematic illustration of the analytic framework of FanSi, illustrating the two-stage decision problem solving process. The first stage is solved with known uncertainties at a high temporal resolution (in this project we use three-hourly resolution). The second stage is solved using scenarios (weather years) to represent future uncertainty related to weather at a weekly time resolution. To reduce computation time, FanSi employs a scenario reduction technique to reduce the number of weather years that need to be explicitly considered in solving the second-stage problem. The second stage has a given time horizon. To represent the system state at the end of this time horizon, water values calculated by EMPS are used. In the present project, we use a time horizon of 52 weeks, 35 historical weather years (1981-2015) and 9 reduced scenarios for the second-stage problem solving. For further details on methods used in FanSi, we refer to the model documentation (Helseth et al. 2017; 2018).

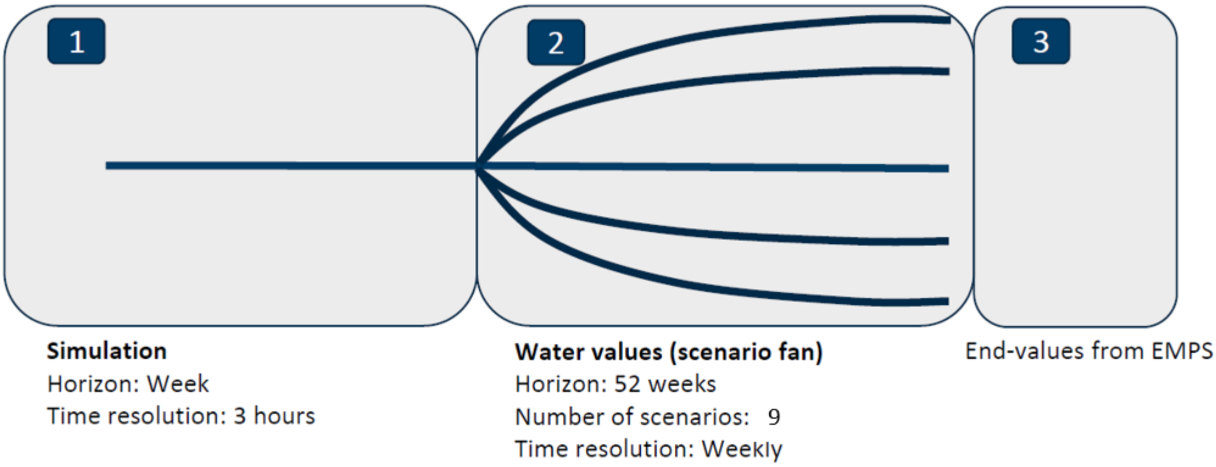

Figure 2 Illustration of the analytic framework of the FanSi model as applied in the current project. Figure credit: Arild Helseth, SINTEF Energy Research.

2.3 EMPS

The EMPS model is a stochastic optimization model that maximizes the expected total socioeconomic surplus in the simulated system through the optimal dispatch of generation and transmission, given a consumption profile (Wolfgang et al. 2009). The EMPS model is a well-tested model used for decades by all main actors in the Nordic power market. To our knowledge, there are no other relevant models with such an advanced representation of the Nordic systems with long- and short-term (hydropower) storage capabilities. We use EMPS as a supplement to FanSi to further substantiate conclusions drawn from the project.

There is no fuel cost for hydropower in the model. However, with a limited amount of water available in the reservoirs as well as a season-dependent inflow, the determination of an optimal strategy for hydropower generation becomes a complex problem. The goal is to find a strategy that maximizes the expected annual operation profits, considering the climatic uncertainties. In this process, EMPS executes two phases: the strategy phase and the simulation phase. In the first phase, water values for each modeled area are calculated using stochastic dynamic programming. In the second phase, the power market is cleared for each time step for each weather year using water values as marginal costs of hydro production. The market clearing uses optimization with hydropower aggregated in combination with heuristics to find individual hydro plant production.

2.4 Primod

Primod is a prototype model developed by SINTEF Energy Research as part of the project "Pricing Balancing Services in the Future Nordic Power Market" (PRIBAS) (Haugen and Helseth 2021). Primod is a fundamental short-term model for power system analyses and multi-market price forecasting. The model is based on linear programming (LP) and mixed integer linear programming (MIP) for solving the unit commitment and least cost dispatch problem. The allocation of electricity and reserve capacity are co-optimized in the model, and a separate module exists to study system imbalances.

The model requires exogenously given long-term valuation of water for individual hydropower reservoirs (water values/cuts) and is thus part of a model hierarchy where these values are obtained from simulations by a long-term model like FanSi or EMPS-W. Initial reservoir fillings are also normally provided by long-term models. The model is typically used to study one week from a specific historical 'weather year', and largely solves the same weekly problem as the FanSi-model. However, Primod has a higher time resolution (down to 15 minutes) and more details represented. The main differences between the long-and short-term models include the time resolution and time horizon (foresight) of the models, the level of detail in modelling thermal power plants and hydropower plants, requirements for reserve capacity, and time resolution for hydro inflows (weekly vs. daily resolution). Whereas FanSi solves weekly optimization problems, Primod solves deterministic daily problems with a rolling horizon to cover a full week. Thus, when solving the first days of the week, the model has no information of what will happen at the end of the week. As water values/cuts are only provided for the end of each week, Primod uses a linear interpolation between the valuation from the end of the previous week and the end of the studied week to estimate water values/cuts for each daily problem. Additional details for thermal power plants comprise ramping constraints, and minimum uptime and minimum downtime, in addition to start-up costs and minimum production also represented in FanSi (but by continuous start-up variables). Primod also has the option to include start-up costs and minimum production for selected hydropower plants.

In this project, Primod was used to study selected/individual weeks with a higher time resolution and more details than the FanSi- and EMPS-models. The model uses the same input data as FanSi and EMPS, but with some additional input concerning thermal power plants and demand for reserve capacity (see Section 5.1.3, Section 5.3.2 and Section 5.4). As the time resolution of input data is hourly (wind and solar) or 3 hours (demand), we used hourly time resolution to limit the computation time of the model. In addition, all binary variables (start-up variables) for thermal and hydropower plants were relaxed due to the reduction in computation time and the ability to extract prices (dual variables) for electricity and reserve capacity. The model was (mainly) used to study the availability of spinning reserve capacity in this project.

3 Environmental constraints for hydropower

This section provides a brief description of data and methods used to implement new environmental constraints for hydropower into the power system models. We used NVE 49:2013 as guidance for selecting locations for environmental flow release, reservoir level constraints and minimum production requirements. All sites in categories "1.1 Høyest prioritet" (English: highest priority) and "1.2 Høy prioritet" (high priority) were included in our analysis. In addition, we included concessions without a time limit ("tidsubegrensede konsesjoner") and a few others that may receive new terms of license before 2030 through a dialogue with NVE. For a full description, see Schönfelder and Harby (2023).

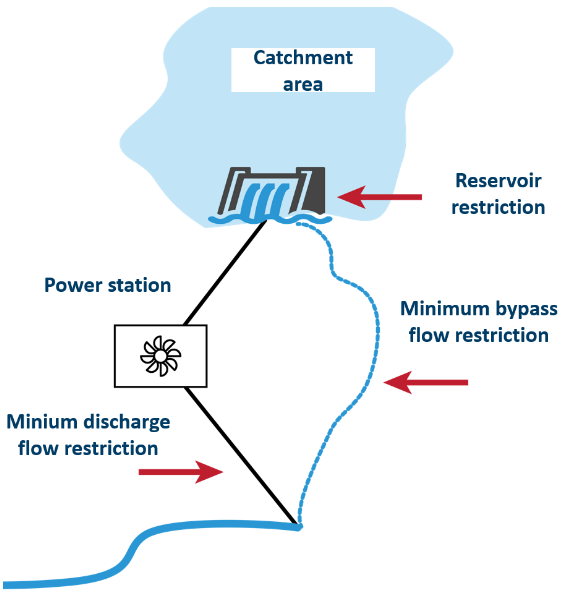

Figure 3 Schematic illustration of the three categories of environmental restrictions considered.

In total, 285 new constraints are implemented for minimum reservoir levels, environmental flow release, and minimum production. 210 different power plants and reservoirs (out of 1288 modelled hydropower modules in Norway) are subject to new constraints, as some are subject to more than one type of constraint. Figure 4 shows the distribution of the new constraints among price areas, where there are most power plants in NO2 and NO5 that are subject to new constraints. The majority of the power plants are subject to either reservoir constraints (mag), environmental flow release (bypass constraints, qforb) or both (mag_qforb).

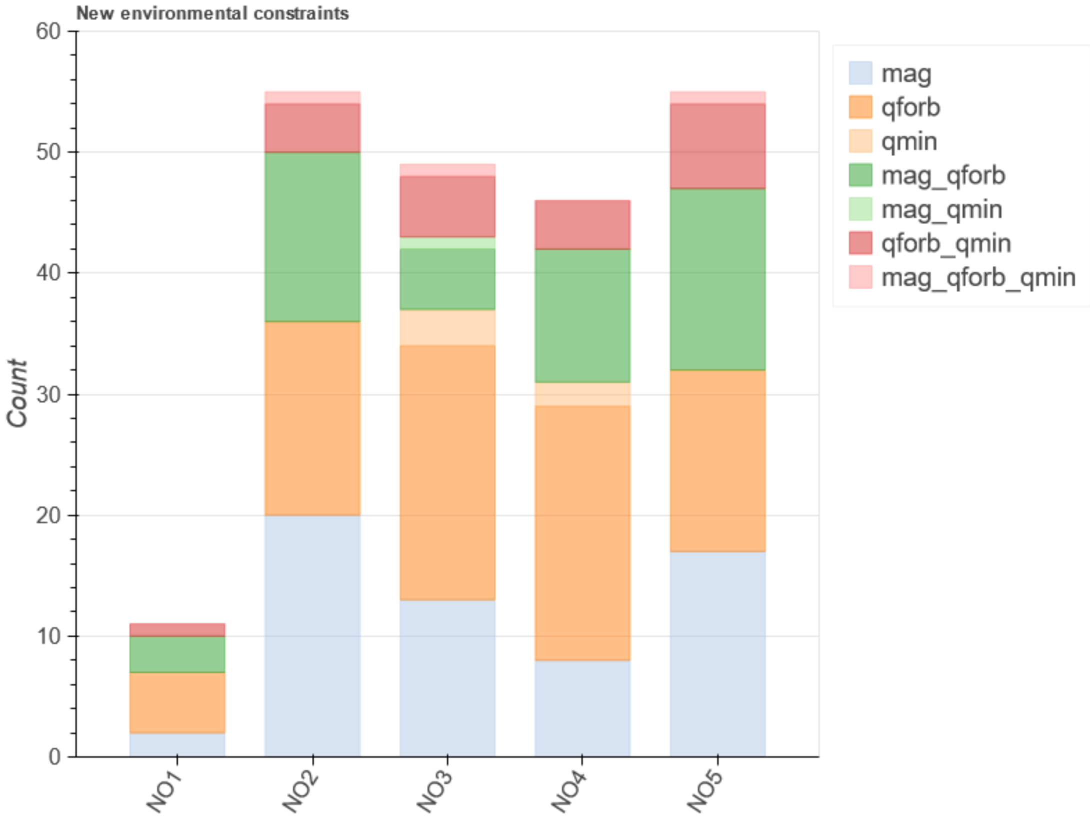

Figure 4 The number of new environmental constraints implemented in each price area in the analysis.

3.1 Minimum reservoir filling

Generally, Norwegian hydropower reservoirs are drawn down during the winter months and they are filled up during the snowmelt period. Depending on production, they may fill up to a low filling degree that can remain throughout the summer. Late filling of reservoirs can conflict with important ecological functions, landscape aesthetics, and boat and recreational use of the reservoirs during summer months. Realistic operational restrictions are filling requirements for reservoirs during summer. Main data source for selection of reservoirs with filling requirements was the NVE 49:2013 report, where potential measures are described for either a specific reservoir or generally for the concession. If not specified, we selected relevant reservoirs based on expert judgement using location and the surrounding environment of the reservoirs. 108 reservoirs are subject to new reservoir filling constraints in the analysis. The requirement is implemented as a soft constraint, meaning that all natural reservoir inflow must be used to fill up the reservoir until the target is reached. Note that discharged water from upstream reservoirs can be used for production, and that bypass and minimum production requirements are prioritized over the reservoir constraints. The constraint period for reservoir constraints is from week 18 (week 22 in NO4) until and including week 33.

The new minimum reservoir constraints are applied to reservoirs representing 21 TWh of the reservoir capacity in Norway (about 25%) of total capacity). The distribution of reservoir capacity and affected reservoir capacity among price areas are shown in Figure 5. See Appendix A.1 for the distribution per model area. Most of the constrained reservoir capacity is found in NO2 and NO5, and the highest share of the total reservoir capacity is constrained in NO3 and NO5.

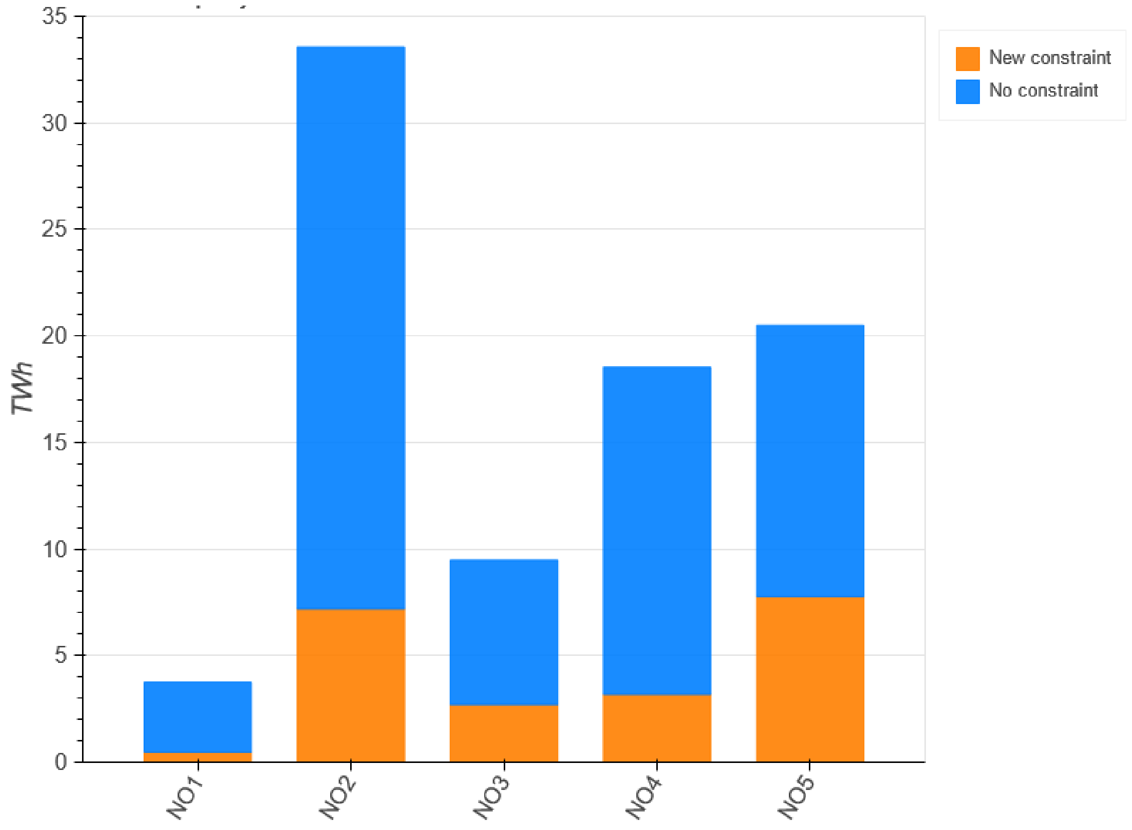

Figure 5 The total reservoir capacity in each price area divided into capacity subject to new constraints and not.

The new minimum reservoir constraints affect directly more than 8 GW of the production capacity in Norway (23%). Note that this number only includes the capacity of power plants directly connected to the affected reservoirs, and not power plants downstream that will also be affected in the constrained period due to reduced inflow. The distribution of affected production capacity and total production capacity among price areas are shown in Figure 6. See Appendix A.1 for the distribution per model area. Most of the affected production capacity is found in NO5 and NO2, where the largest fraction of total production capacity is affected in NO5.

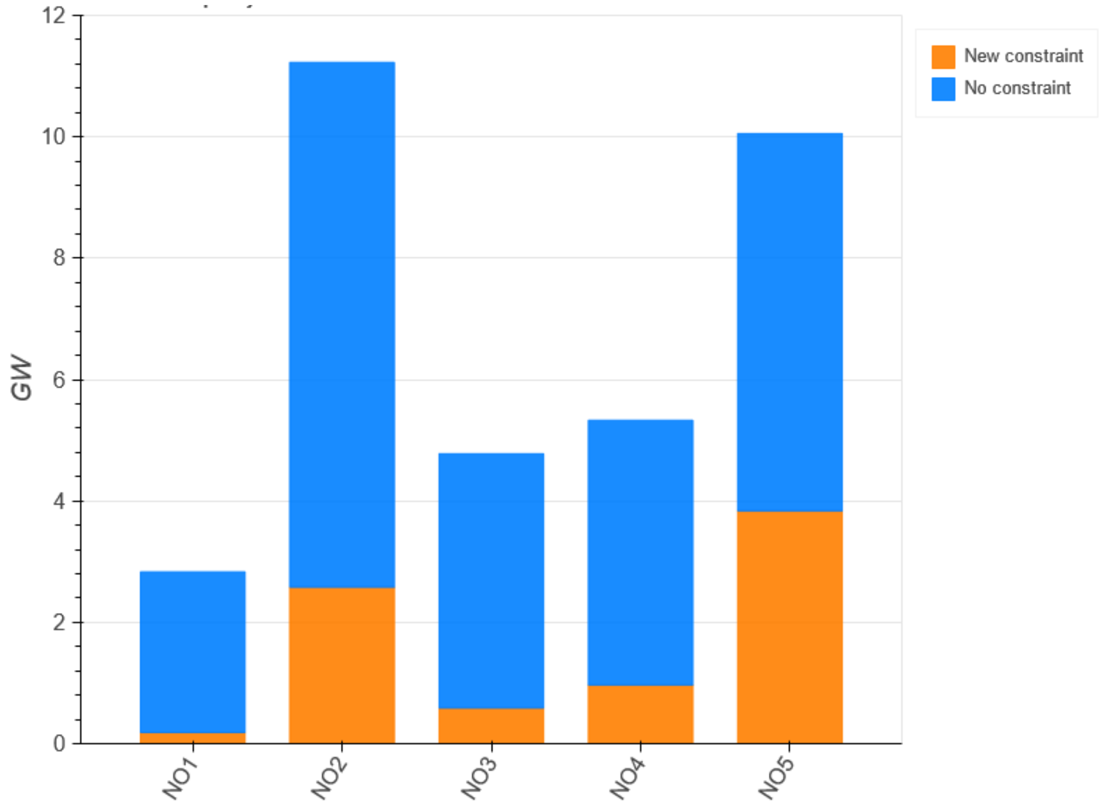

Figure 6 The total production capacity in each price area divided into capacity subject to new reservoir constraints and not.

3.2 Minimum environmental flows

148 power plants are subject to revision of terms of concession that may lead to new environmental flow releases to bypassed or downstream reaches of affected rivers.

We decided to use Q95-flow as starting value for calculation of environmental flow releases in bypass sections. The regression model Nevina was selected to calculate the Q95 flow values of the different hydropower catchments. The main reasons to use Nevina are the following:

- Spatial availability on the entire Norwegian mainland
- Acceptable expected accuracy in comparison to precipitation-runoff models, using catchment drainage points for automatization of the workflow
- Option to batch processing of many catchments drainage points for automatization of the workflow

We defined a framework to identify the contributing catchments to the bypass reach, i.e. we identified the drainage area that would drain into the bypass reach under natural conditions before the impact of hydropower production. We further identified the bypassed river reaches by defining a start and an endpoint on the river network. Figure 7 shows an example on a map of the Q95 catchment of Grytten power plant with start- and endpoints of the relevant bypass reach that will receive environmental flow. The plant is part of a more complex hydropower system, but only one catchment would contribute to the bypass flow in an unregulated scenario.

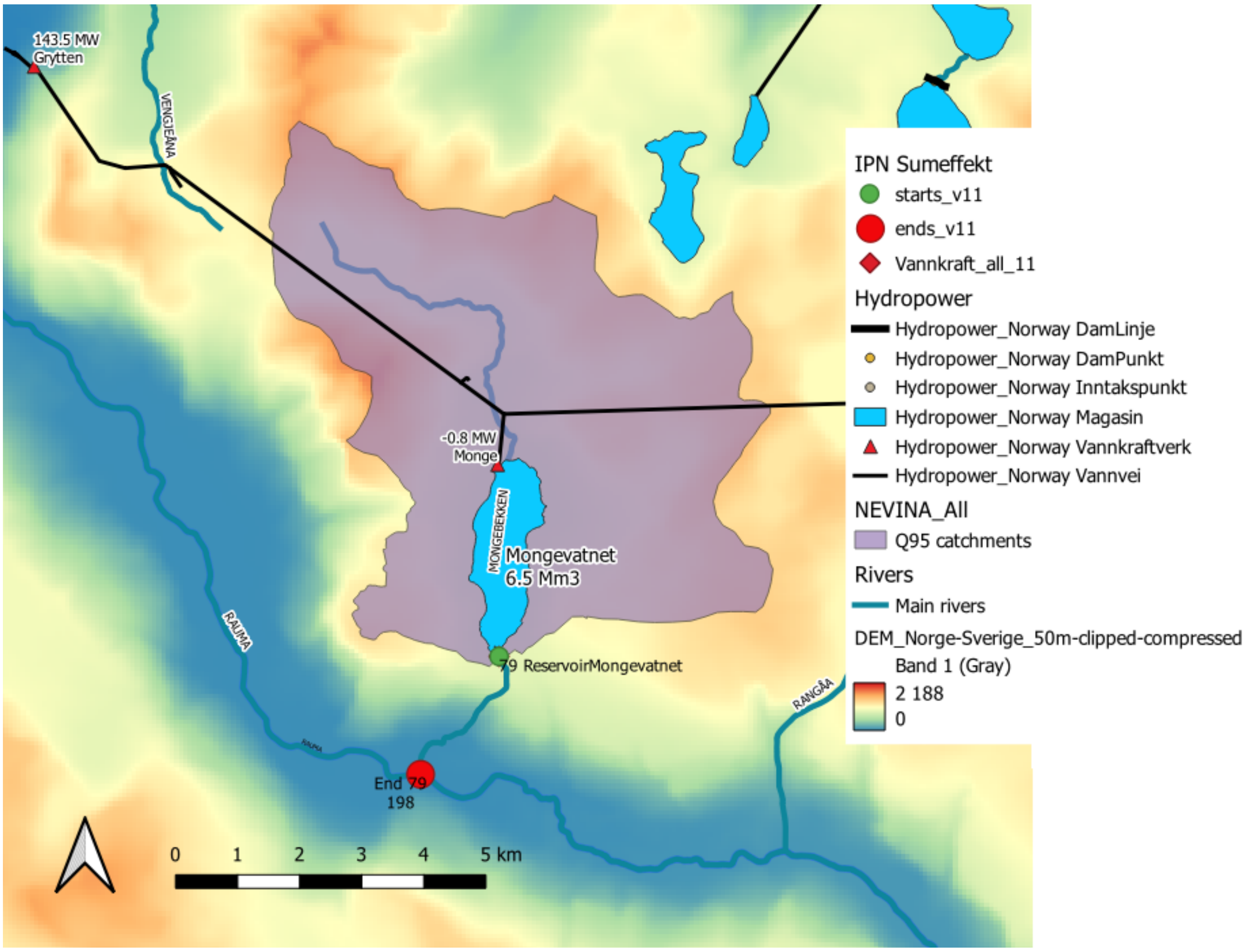

Figure 7 Grytten power plant and Mongevatnet reservoir with its Q95 catchment between the green and red mark. The grey area is the natural catchment of the river. Water is transferred to Mongevatnet from east, but this catchment is not included in calculation of Q95.

We compared the calculated Q95 values of Nevina with measured discharge data to estimate uncertainty and detected regional and potentially other biases. There is moderate uncertainty in measured flow data, and high uncertainty in the modelled Q95. Mean errors for summer Q95 and winter Q95 are 1.66 m^3/s and 1.01 m^3/s respectively. A Principal-component-analysis revealed that there are no biases for region, size or catchment land use for neither summer nor winter Q95.

Using Q95 is a very general rule for environmental flow release which cannot be considered realistic. Comparison with existing concessions and currently revised terms of licenses revealed that Q95 often overestimates the applied environmental flows. We developed the SumEffekt-method, a classification system to adjust the Q95 values linearly with factors between 0.18 and 1.52, i.e. ranging between 18% and 152% of the original Q95. The linear correction factor is dependent on three characteristics of the river reach receiving environmental flow release and the actual hydropower plant.

In the following sections 3.2.1, 3.2.2, and 3.2.3, we describe their meaning and how we calculated each of them. Each of the characteristics results in a score ranging from one to three in discrete steps, and the three scores are in turn combined into a multiplication factor between 0.18 and 0.52 (see Figure 12).

3.2.1 Aggregated environmental value and impact (VPS) of the river reach

The value-impact-score (here VPS according to *Verdi-Påvirknings-Score* in NVE 49:2013 report) is calculated based on a combination of the estimated non-monetary value of the ecosystem and the assessed impact of the hydropower regulation, see Table 2. We give a short summary of how the values and impact of each concession system were assessed, for a more detailed description we refer to the memo by Schönfelder and Harby (2023).

The value of the waterbody was assessed according to three different topics:

- Fish and fishing
- Other biodiversity
- Recreational activities

The Value-Impact of the regulated river system are based on the characteristics given in NVE 49:2013:

Table 2 Value-Impact matrix. The VP class between 1 and 5 is inferred from the Value of the system and the respective Hydropower impact on the system (from NVE 49:2013).

Value-Impact (individual topic)	**Impact by hydropower regulation**			
Value	Very high	High	Medium	Low
Very high	VP5	VP5	VP4	VP2
High	VP5	VP4	VP3	VP1
Medium	VP4	VP3	VP1	VP1
Low	VP2	VP1	VP1	VP1

Table 3 VPS score generation from the distribution of Value-Impact classes (from NVE 49:2013).

VPS (all topic scores combined)	**Requirement**
VPS5	Maximum one topic in VP5 or more than one in VP4
VPS4	Maximum one topic in VP4
VPS3	More than one topic in VP3
VPS2	Maximum one topic in VP3 or more than one in VP2
VPS1	Maximum one topic in VP2 or all in VP1

In report 49:2013, the VPS scores for all concessions were assessed case by case. We extracted the VPS values using R and the regex package. We transformed the VPS values into our score system ranging from one to three. VPS5 are equivalent to score 3, VPS4 are equivalent to score 2, and VPS3, VPS2 and VPS1 are equivalent to score 1.

The distribution of VPS scores in report 49:2013 and the distribution of Sumeffekt VPS score are represented in Figure 8 and Figure 9 respectively.

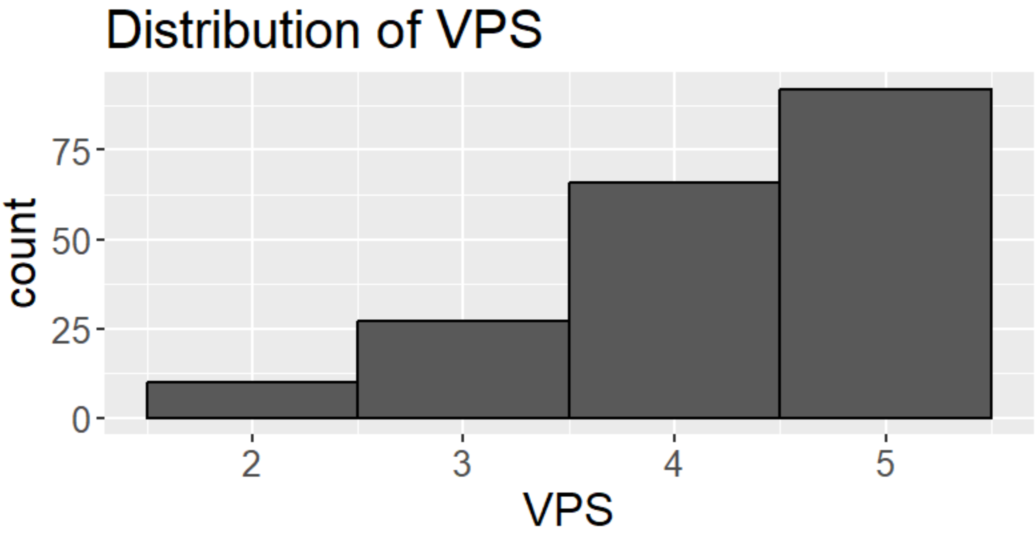

Figure 8 Distribution of VPS of retrieved concessions from NVE report 49:2013

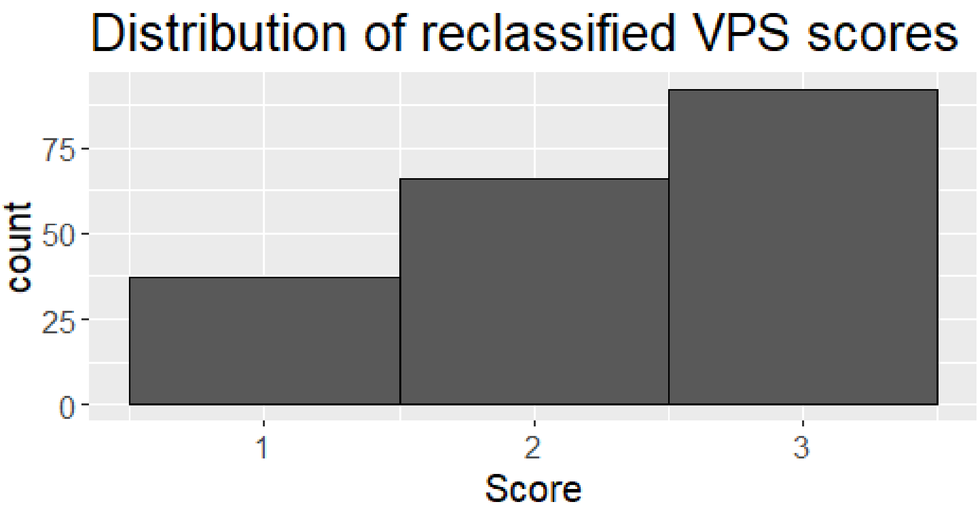

Figure 9 Distribution of VPS scores reclassified for SumEffekt method

3.2.2 Energy equivalent score of the power plant

The energy equivalent (eneq) of a hydropower plant is the potential power generated per m^3 of water. The energy equivalent is related to the gross head. This means that 1 m^3/s of flow gives a higher amount of power generated at a site with high energy equivalent (high head) than at a site with low energy equivalent (low head). Releasing water from a site with high energy equivalent represents a higher loss in energy generation than releasing the same amount of water from a site with low energy equivalent. An energy equivalent of 1 corresponds to circa 400m of gross head of the plant. This information was extracted from the hydropower descriptions in the dataset.

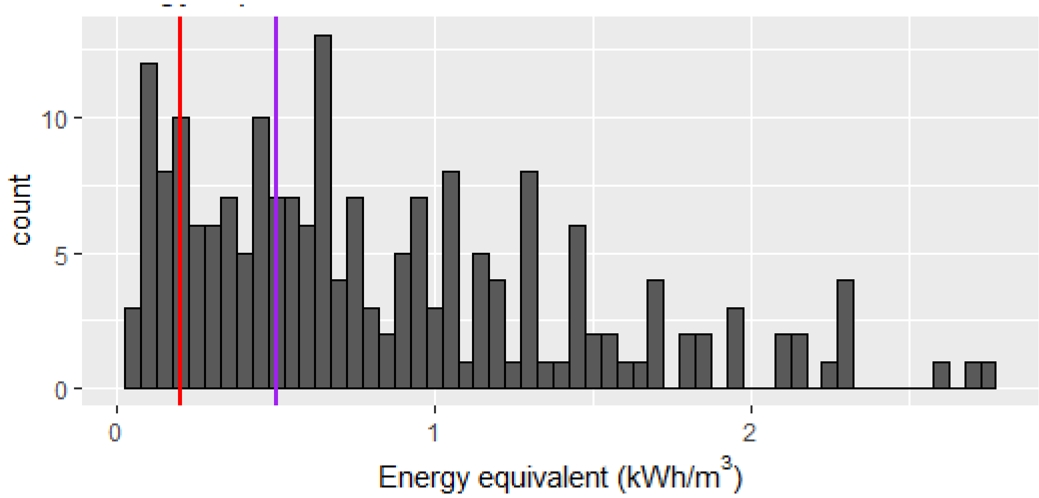

Figure 10 Distribution of energy equivalent and class borders at 0.2 (red line) and 0.8 (purple line).

We reclassified energy equivalent to a score. An eneq value below 0.2 (red line in Figure 10) is classified as 1, and above 0.5 (purple line in Figure 10) is classified as class 3, all values in between are classified as 2.

3.2.3 Gradient score – River slope of the river reach to receive environmental flow release

The effect of releasing water to a river depends on the morpho-dynamic characteristics of the river, especially the cross-sectional shape, the longitudinal gradient (river slope) and the substrate conditions. We chose the river slope as a simple indicator of the effect of environmental flow release. In a river with a very steep slope (e.g. >9%), the water velocity will be high and low flows will only cover a small part of the river width giving a low water-covered area. We expect smaller ecological benefits from additional environmental flow for these rivers, i.e. these rivers receive a low score (1) for the slope. A small water release to a river with lower slope will cover a larger part of the width giving a higher water-covered area compared to releasing the same amount of water to a steeper river (6%-9%). We expect a medium to high ecological benefit for higher environmental flows, therefore assigning gradient score 3 for the range 6%-8% and score 2 for 8%-9% to introduce a stepwise reduction of score to the lowest score above 9%. For flat and moderate slopes (0%-6%), we expect that a lower amount of water would result in a significant water-covered area and good ecological benefits. This means that the need for environmental flow is less, therefore assigning gradient score of 2 for this range.

The river slope was found by dividing height difference by bypass reach length. We defined start and end points of the bypass reaches and used river network data downloaded from NVE. We used the QGIS python interface to determine the shortest path between the points along the river, which is exactly equal to the length to the bypass reach. We sampled a 10 m DEM of Norway to determine the altitude of both start- and endpoint.

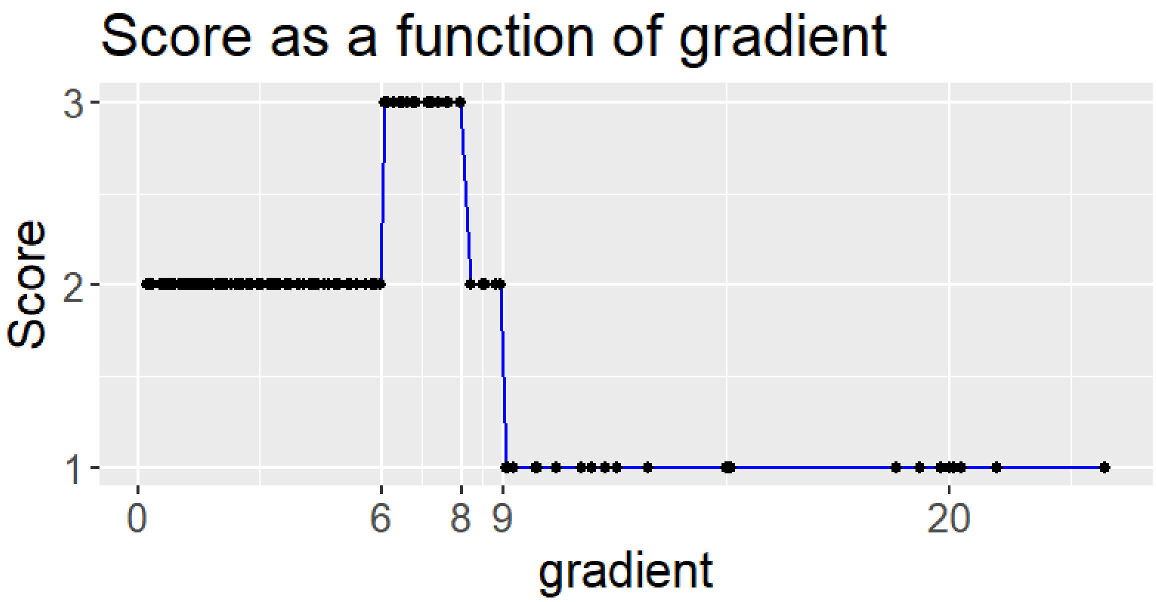

Figure 11 Gradient score function. Blue lines indicate the function, black circles indicate measured gradients of bypass reaches.

3.2.4 Combining characteristics for final score

To calculate the final score, the VPS score, energy equivalent score and gradient score are assigned weights to represent their importance. The VPS score has the largest influence on the percentual change of the Q95, followed by influence of energy equivalent (enekv), and lastly the river gradient. To calculate the final correction factor (far right column "Factor" in Figure 12), we used the VPS score, energy equivalent score, and gradient score – each of them ranging from 1-3 in discrete natural number steps. The factor is then used as a multiplier for Q95 values, individually for summer and winter to calculate the final environmental release flow in m^3/s. The frequency column in Figure 12 describes the occurrence of each combination of scores.

Category	VPS	Energy equivalent	Gradient	Frequency	Factor
1	3	3	3	2	1,52
2	3	Low energy equvivalent	2	7	1,5
3		3	1	1	1,48
4		2	3	2	1,42
5	VPS score 5	Medium energy eq.	2	8	1,4
6		2	1	6	1,38
7	3	1	3	13	0,55
8	3	High energy eq.	2	36	0,5
9	3	1	1	18	0,45
10	2	3	3	0	1,02
11	2	3	2	9	1
12	2	3	1	1	0,98
13		2	3	1	0,95
14	VPS score 4	2	2	14	0,9
15		2	1	2	0,85
16	2	1	3	5	0,44
17	2	1	2	23	0,4
18	2	1	1	12	0,36
19	1	3	3	0	0,3
20	1	3	2	11	0,3
21	1	3	1	0	0,3
22		2	3	0	0,27
23	VPS scores 1-2-3	2	2	10	0,25
24		2	1	1	0,23
25	1	1	3	4	0,22
26	1	1	2	8	0,2
27	1	1	1	4	0,18

Figure 12 SumEffekt method table combining VPS, Energy equivalent and Gradient scores to one Factor. The column "Frequency" shows how many sites there are in each category.

We consider environmental flow values below 50 l/s for unrealistic due to their low environmental function and the challenge of technical accuracy and precision to release such low flows. We introduced a minimum release of 50 l/s for all sites and replaced all flow values below this threshold accordingly.

3.2.5 Comparison to given terms of concession

We compared results of environmental flow releases from the Q95-method and the SumEffekt-method (adjusted Q95 values according to Chapter 3.2.4) to already decided flow releases in finalized revision processes. A dataset of nine powerplants available at the time was used for this analysis.

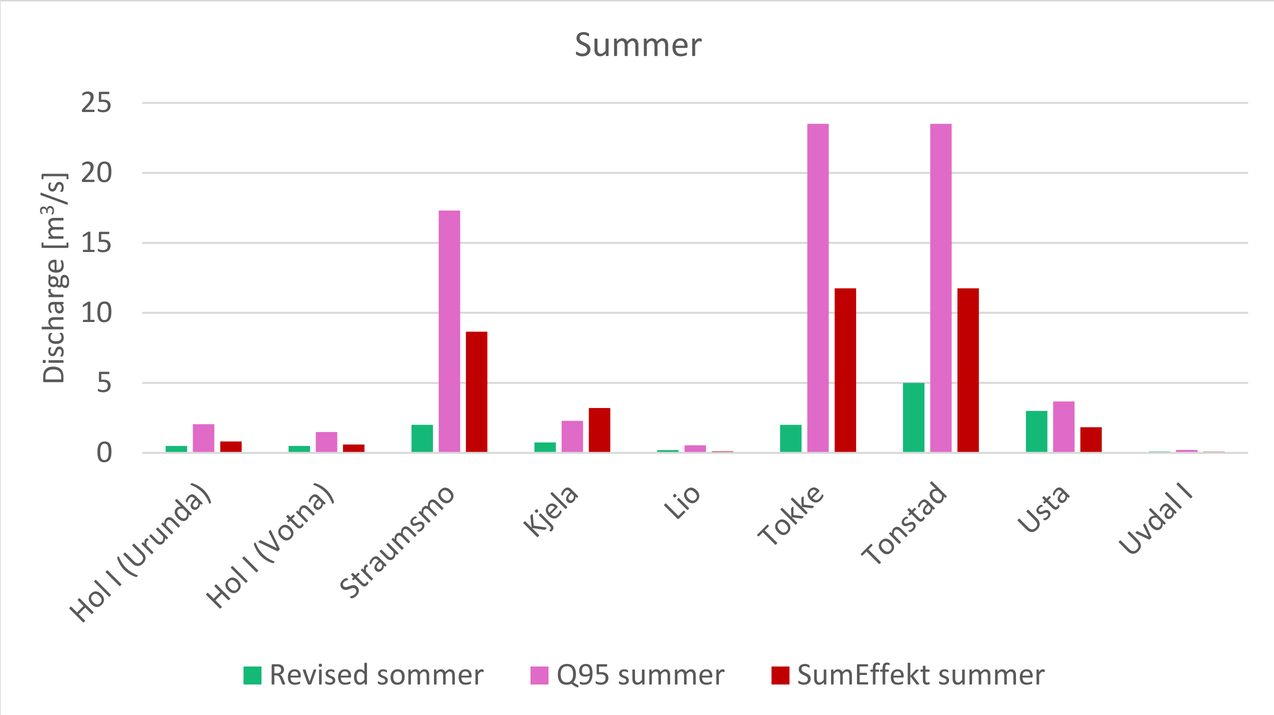

Figure 13 Comparison of realized environmental flows (Revised summer) with Q95 (Q95 summer) and Sumeffekt-method (SumEffekt summer) for summer months.

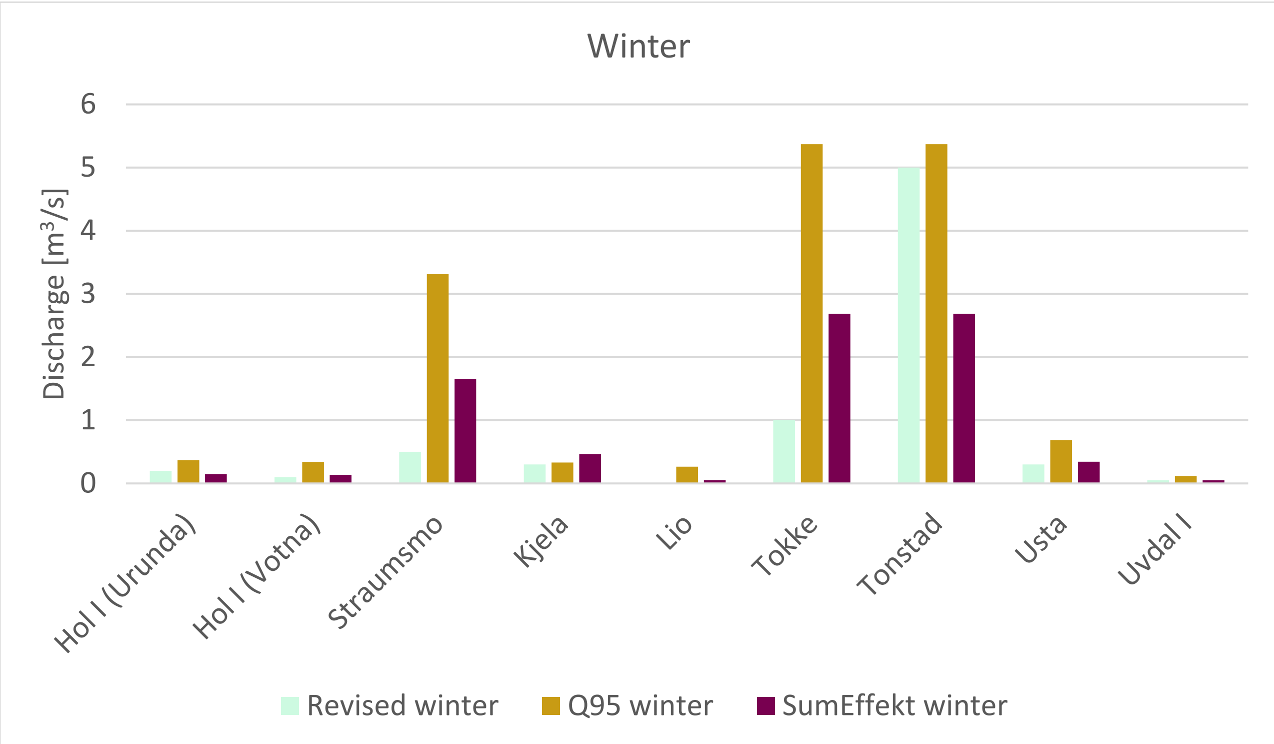

Figure 14 Comparison of realized environmental flows (Revised winter) with Q95 (Q95 winter) and Sumeffekt-method (SumEffekt winter) for winter months.

Both Figure 13 and Figure 14 show that the natural Q95 exceeds the real environmental flow given by renewed license terms, in some cases by more than 100% e.g. Straumsmo (both seasons) and Tokke (summer only). For both summer and winter, Figure 13 and Figure 14 show that the SumEffekt method is often closer to real environmental flows, especially for flows below 1 m^3/s, e.g. Hol I and II, Usta and Uvdal I.

3.2.6 Theoretical power loss due to environmental flows

An a priori analysis of the effects of environmental flow releases on the power market was done to estimate the power losses and to evaluate the Sumeffekt method in terms of realism. The analysis shows the following:

Due to lower inflow during winter, the requirements for environmental flow releases are lower from week 39 to week 18 (week 22 in NO4), and higher from week 18/22 to and including week 38. Environmental flow requirements are given in m^3/s, but the bypassed water can be translated into lost production in GWh by using the energy equivalents from the bypassed stations. Figure 15 shows the distribution of lost power production in each price area due to environmental flow requirements, for both summer and winter periods. See Appendix A.1 for the distribution per model area. We see that the loss is higher during summer (even though this period is shorter in time) due to higher requirements in this period. NO2 and NO5 are subject to the highest losses.

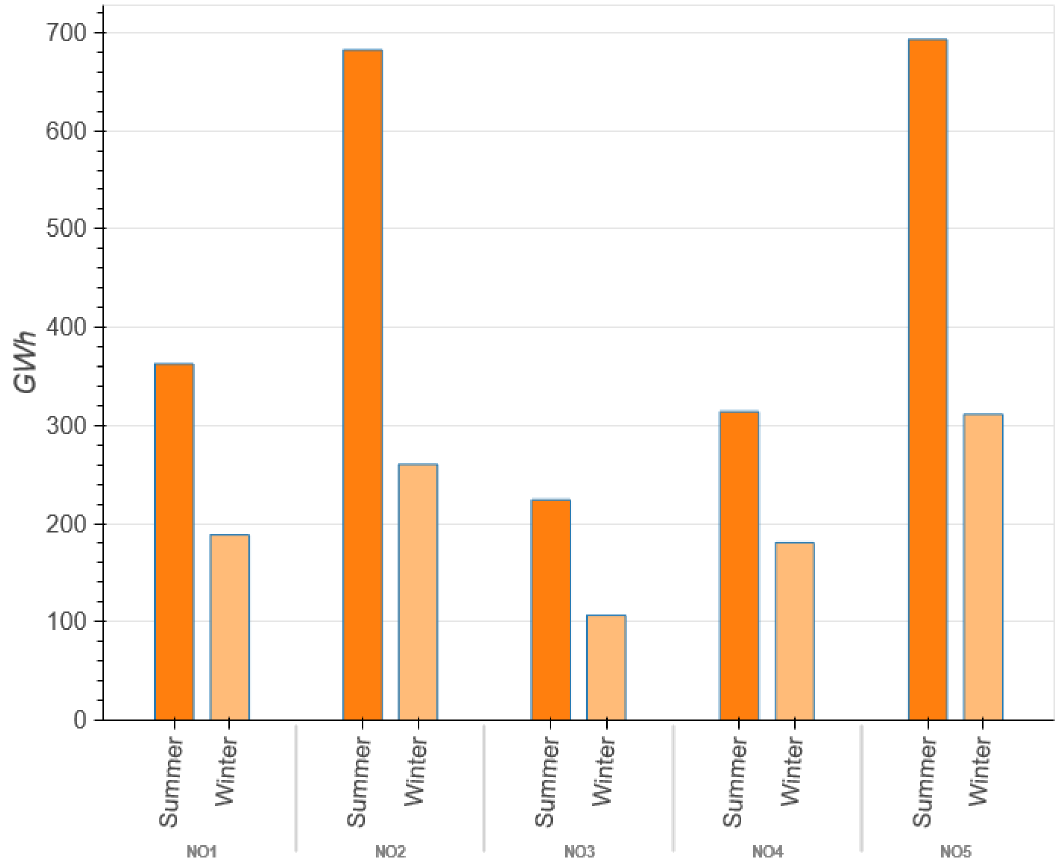

Figure 15 The total theoretical production loss during summer and winter due to the new environmental flow releases to bypassed reaches per price area.

3.3 Minimum production

Fast drastic reduction of hydropower production by reducing flow through the turbines or stopping turbine(s) entirely can lead to sudden reduction in water covered areas downstream of the outlet. A potential measure against this effect is to introduce a minimum production flow.

We identified all concessions that contained the recommendation of minimum production flow in NVE 49:2013. We then applied the general rule of setting the minimum production flow as 30% of the maximum capacity of the turbines.

If the current plant set-up does not allow an operation with as little as the recommended production flow, the operator may decide to install an additional turbine to increase the operational range down to the recommended minimum production flow. If installation costs of additional or changed turbine setup is not economically feasible, they may just spill the water instead to fulfil the environmental requirement. Another option could also be to produce more than the required minimum production. We generalized this, and assumed the minimum downstream flow would always be used for hydropower production.

29 power plants are subject to minimum production requirements in the analysis. The requirements are set at 30% of the production capacity and are constant throughout the entire year. Table 4shows the total capacity per price area that becomes inflexible by these requirements. The table also shows that this capacity is small compared to the total production capacity of each area. Furthermore, the number of minimum production requirements is relatively low (29 compared to 148 for minimum environmental (bypass) flows and 108 for reservoir restrictions), and they show only small impacts on the overall power system in our simulation results. For these reasons, in the remainder of this report the minimum production requirements will not be further addressed.

Table 4 New constraints on minimum production implemented per price area and the share of total production capacity.

Price area	Total new minimum production	% of total production capacity
NO1	0.33 MW	0.01
NO2	116.8 MW	1.04
NO3	162.6 MW	3.40
NO4	168.2 MW	3.16
NO5	143.6 MW	1.43

4 Analysis overview

This section first provides an overview of the analysis in terms of the scenarios considered for the power system in the modelling with FanSi and EMPS (Section 4.1), where each scenario defines a specific power system in the year 2030. Then, the selection of weeks individually analyzed with Primod is presented (Section 4.2).

4.1 Scenarios for the power system

We define and analyze eighteen scenarios for the power system in the year 2030 (Table 5)[2]. The scenarios are organized in pairs, with each pair consisting of one scenario without new environmental restrictions and one with new restrictions. Scenarios without new environmental restrictions serve as reference points against which the effects of environmental constraints are assessed. In other words, we evaluate the effects of environmental restrictions by comparing results for scenarios with and without these restrictions. Furthermore, we analyze the effects of environmental restrictions under different assumptions regarding power system characteristics, such as power demand or fuel prices.

[2] We also analyzed the power system for 2015 during the project. However, results for 2015 were not found to yield insights additional to those obtained from the 2030 analyses. Therefore, 2015 results are not included in this report.

Table 5 Overview of scenarios analyzed. All scenarios represent power systems for the year 2030.

Scenario name	Environmental constraints	Scenario characteristics
Base		
Base_R-Q	Reservoir, flow	
Base_EMPS		EMPS model (replacing FanSi)
Base_EMPS_R-Q	Reservoir, flow	EMPS model (replacing FanSi)
Base_R	Reservoir	
Base_Q	Flow	
Base_R*-Q	Reservoir (strong), flow	
Base_R-Q*	Reservoir, flow (strong, Q95)	
LowDem		Low demand
LowDem_R-Q	Reservoir, flow	Low demand
HighDem		High demand
HighDem_R-Q	Reservoir, flow	High demand
HighDem_HighSolar		High demand, high solar production
HighDem_HighSolar_R-Q		High demand, high solar production
HighPrice		High fuel and CO_2 prices
HighPrice_R-Q	Reservoir, flow	High fuel and CO_2 prices
LowTransm		Low transmission
LowTransm_R-Q	Reservoir, flow	Low transmission

The naming convention for scenarios is based on listing up to three scenario features separated by underscores ('_'). The features related to power system characteristics or choice of power system model are listed first in the scenario name. There may be one or two such features. For instance, 'Base' scenarios encompass our standard assumptions regarding factors such as power demand and fuel prices, while 'HighDem_HighSolar' incorporate both higher assumed power demand and increased solar power generation compared to 'Base'.

In scenarios where environmental restrictions are included, this is indicated last in the scenario name using combinations of the letters 'R' and 'Q'. 'R' denotes reservoir restriction and 'Q' minimum flow requirement. Note that we treat minimum bypass flow requirements and minimum production flow requirements together. Therefore, 'Q' scenarios encompass both these two flow requirement variants.

An asterisk ('*') added to the letters 'R' or 'Q' indicates a stronger implementation of the restriction than the default. 'R*' means that both local inflow and water from upstream power plants must be accumulated in reservoirs subject to active restrictions, unlike in the default 'R' scenarios where only local inflow needs to be accumulated. 'Q*' signifies that minimum bypass flow requirements are set equal to Q95 (i.e., the seasonal flow that is naturally exceeded 95% of the time), unlike the default 'Q' which is based on the new method for estimating minimum bypass requirements developed in this project.

One scenario pair, the pair of 'Base_EMPS' and 'Base_EMPS_R-Q', stands out due to the use of the EMPS model instead of the FanSi model. Data and assumptions for this scenario pair ('Base_EMPS' and 'Base_EMPS_R-Q') are identical to those of 'Base' and 'Base _R-Q.' The difference lies in the use of EMPS in the former case and FanSi in the latter. Utilizing the EMPS model offers an alternative set of results derived from a different approach.

The list below summarizes the scenario features considered without going into detail. More detailed accounts are provided later in Section 5.

- 'Base' scenarios incorporate standard assumptions about factors such as power demand and fuel prices. These assumptions are considered as the default.
- 'EMPS' scenarios utilize the EMPS power system model, replacing the default model FanSi.

- 'LowDem' scenarios are distinguished by lower assumed power demand for Norway and Sweden compared to 'Base'.
- 'HighDem' scenarios are distinguished by high assumed power demand for Norway and Sweden compared to 'Base'.
- 'HighDem_HighSolar' scenarios include both higher assumed power demand and higher solar power generation compared to 'Base'.
- 'HighPrice' scenarios contain higher prices for natural gas and CO_2 emission allowances compared to 'Base'.
- 'LowTransm' scenarios have all transmission capacities reduced to 90% of default capacities.
- 'R' scenarios include reservoir restrictions under default assumptions, meaning that the requirement is that only local inflow must be accumulated in reservoirs subject to active restrictions.
- 'R*' scenarios include reservoir restrictions under stricter assumptions than our base assumptions. With the relatively stricter assumptions, both local inflow and water from upstream power plants must be accumulated in reservoirs subject to active restrictions. Even though this formulation of reservoir restrictions is not defined as our base, it is still relevant given the varying implementation of reservoir restrictions in reality.
- 'Q' scenarios include both minimum bypass flow requirements and minimum production flow requirements under default assumptions.
- 'Q*' scenarios are the same as corresponding 'Q' scenarios, except that Q* is used to represent minimum bypass flow requirements instead of the default assumptions.

While the full set of scenarios are analyzed with FanSi (or EMPS), subsequent analyses with Primod are based on 'Base' and 'Base_R-Q'.

4.2 Selected weeks for Primod analysis

Primod is a short-term model used to analyze individual weeks in detail. The goal of the Primod-analyses is to investigate whether a more detailed model gives additional insights into the effects of environmental constraints. We seek to examine a varied selection of weeks that cover several relevant situations, including the more extreme. The FanSi simulations comprises 35 inflow years of 52 weeks each, 1820 weeks in total. Primod is used to analyze only a selection of these weeks in more detail. These are summarized in Table 6 and explained further in the following text.

Table 6 The weeks selected for Primod analyses were based on spot prices (196 weeks in total).

<table>
<tr><th>Type of week</th><th>Number of weeks</th><th>Combined number of weeks</th><th>Combined number of weeks</th><th>Total number of unique weeks</th></tr>
<tr><td>High spot price</td><td>29</td><td rowspan="3">126</td><td rowspan="5">157</td><td rowspan="5">196</td></tr>
<tr><td>Low spot price</td><td>29</td></tr>
<tr><td>Average spot price</td><td>68</td></tr>
<tr><td>Large absolute price difference</td><td>56</td><td rowspan="2">63</td></tr>
<tr><td>Large relative price difference</td><td>56</td></tr>
</table>

High standard deviation in price	28	87	87	
Large difference in standard deviation in price	66			

We base the selection of weeks on spot prices, as prices often reflect the state of the reservoirs (low, high, or average reservoir fillings) or the state of the power system (high or low demand residual, export/import). We consider this selection to include/cover all seasons and periods where the power system is strained, e.g., low reservoir levels (dry) and high consumption (high prices) or high reservoir levels (wet) and low demand residual (low prices). We also include weeks with normal price levels, and weeks with large variations within the week. The weeks were selected based on the results from the FanSi simulations (Base and Base_R-Q) and spot prices for both the Ostland area (NO1) and Helgeland area (in NO4). The two areas were selected to capture regional differences. Table 6 and the list below summarize the type of weeks chosen. Initially, 580 weeks were selected, but as a week can be selected multiple times based on several criteria and from both scenarios and areas, only 196 weeks were unique. Figure 16 shows the properties of each chosen week, and that one week can have several properties, e.g., high spot price and large price difference.

- Based on mean weekly spot price:
  - Absolute spot price:
    - The 25 weeks with highest mean spot price for both scenarios (with and without environmental constraints) for both areas (NO1 and NO4) = 100 weeks (29 unique weeks, when excluding five weeks considered unrealistically extreme: (1985, 18), (1986, 15), (1986, 16), (1986, 17), (1987, 15)).
    - The 20 weeks with lowest mean spot price for both scenarios (with and without environmental constraints) for both areas = 80 weeks (29 unique)
    - The 20 weeks with the most average mean spot price for both scenarios (with and without environmental constraints) for both areas = 80 weeks (68 unique)
  - Difference in spot price between scenarios:
    - The 20 weeks with largest positive and largest negative weekly mean price difference between the scenarios (with minus without environmental constraints/Base_R-Q change) for both areas = 80 weeks (56 unique)
    - The 20 weeks with largest positive and largest negative relative weekly mean price difference between the scenarios (with minus without environmental constraints/Base_R-Q change) relative to the mean weekly price for the scenario without constraints for both areas = 80 weeks (56 unique)
- Based on weekly standard deviation in spot price:
  - Absolute standard deviation:
    - The 20 weeks with highest standard deviation in spot price for both scenarios (with and without environmental constraints) for both areas = 80 weeks (28 unique).
  - Difference in standard deviation between scenarios:
    - The 20 weeks with largest positive and largest negative difference in standard deviation between the scenarios (with minus without environmental constraints/ Base_R-Q change) for both areas = 80 weeks (66 unique)

The 126 (absolute spot price) + 63 (price difference) + 87 (standard deviation) gives 196 unique weeks (of 276). All week numbers and weather years are represented.

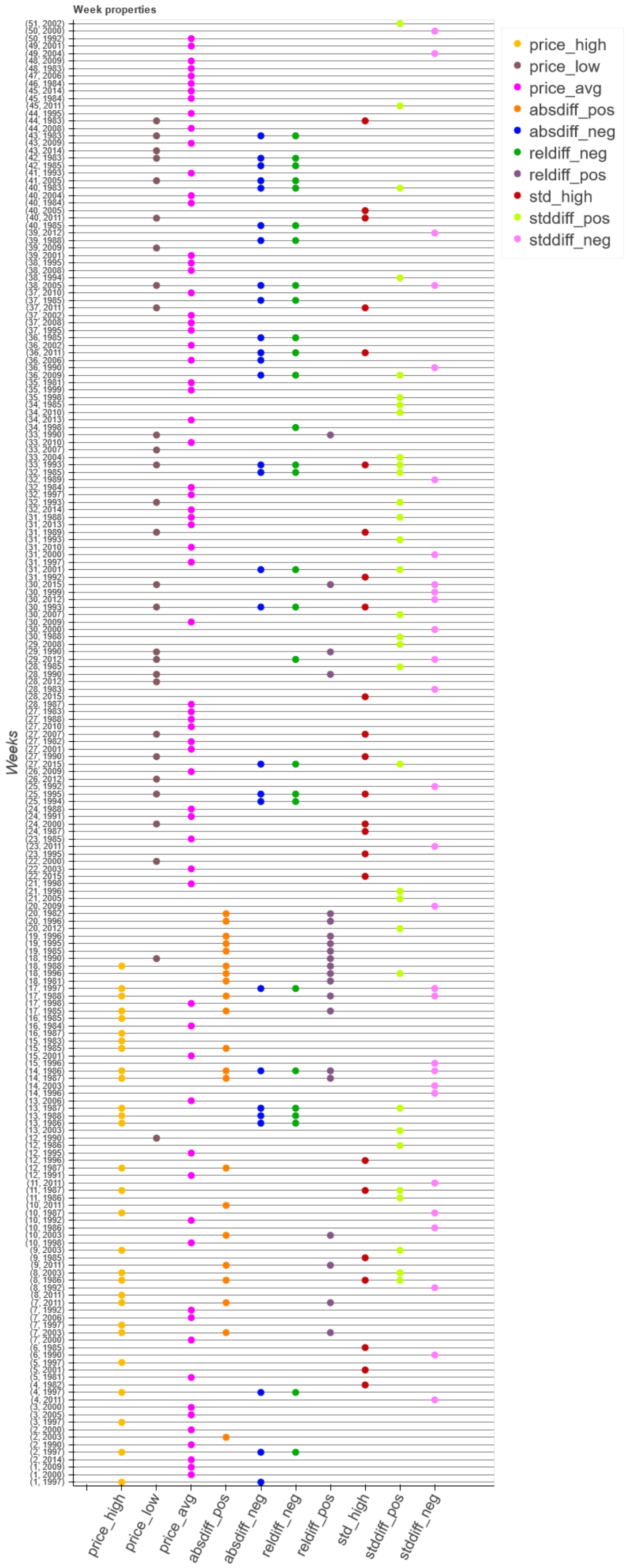

Figure 16 The properties of the selected weeks for Primod analyses.

5 Power system data

This section describes the construction of the dataset used to represent the Northern European power system in 2030. Power generation, consumption and transmission are dealt with in Sections 5.1, 5.2 and 5.3, respectively. Last, Section 5.4 describes data and assumptions for the modelling of reserve requirements using the Primod model.

5.1 Power generation

Assumptions regarding power generation are largely based on NVE's "Langsiktig kraftmarkedsanalyse 2020-2050" (NVE 2020). This reference presents figures for total power production per country (Norway, Sweden, Finland, Denmark, Germany, Netherlands, France, and Great Britain) for 2030, and total power production and installed capacity per technology ("Hydropower", "Wind power" 'Solar power", "Nuclear" and " Other thermal") for countries in the Nordic region. The production per price area in the Nordic countries is also provided. Overall production mixes are summarized in Figure 17 and Figure 18.

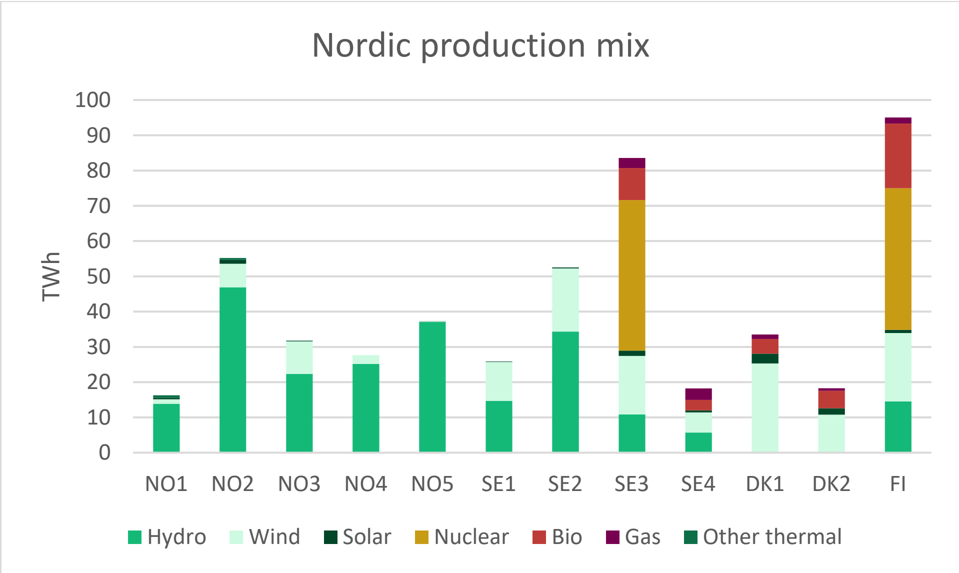

Figure 17 Production mix for all price areas in the Nordic region.

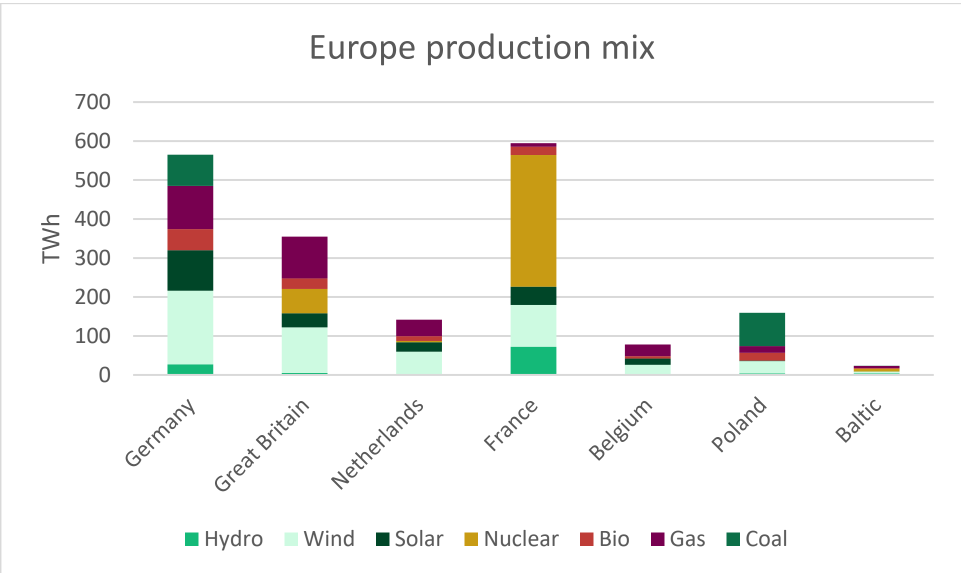

Figure 18 Production mix for other modelled European countries.

In the following subsections, we detail the assumptions for hydropower, wind and solar power, and thermal and nuclear power, respectively.

5.1.1 Hydro

Norway

NVE provided data input files ("DETD" data files) for representing hydropower systems, including representations of topology, reservoirs, water courses, existing environmental restrictions, and power plants. Certain modifications were then made to the data. In particular, the original production-discharge curves were replaced by more detailed curves available from the HydroCen Low Emission 2030 scenario dataset (Schäffer and Graabak 2019).

In addition, NVE uses a different area configuration for Norway, and work was done to distribute the watercourses according to the area division in the current dataset. Note that the description provided by NVE is for 2018 and lacks some newly installed capacity or capacity expected to be installed by 2030. To incorporate this new capacity by 2030 in a simplified manner, we added generic "dummy" hydropower modules in the various model areas. This adjustment ensures that total simulated hydropower production for Norway in 2030 is approximately consistent with figures reported in recent NVE and Statnett publications. The dummy modules are implemented as one regulated reservoir and power plant per area.

In the results from the simulations, total average hydropower production in Norway in 2030 amounts to 147 TWh year^{-1} in the base model runs without new environmental restrictions, and 144 TWh year^{-1} in base model runs with new restrictions (the difference between the numbers stems from reduced production resulting from new restrictions, as will be discussed in detail later in section 6). This compares with corresponding numbers for 2030 of 144-145 TWh year^{-1} indicated in recent publications by NVE (NVE 2023c) and Statnett (Statnett 2023). Note that simulated or estimated future average hydropower production are affected by uncertainties related to hydropower plant characteristics and climate change impacts on inflow, among other factors (NVE 2022; 2019).

Regulated and unregulated water inflow to hydropower producing units were included for 35 years, from 1981 to 2015. To give an impression of both the seasonal profile and year-to-year variability for Norway, Figure 19 shows total hydropower inflow for Norway over the year for each of the 35 historical years.

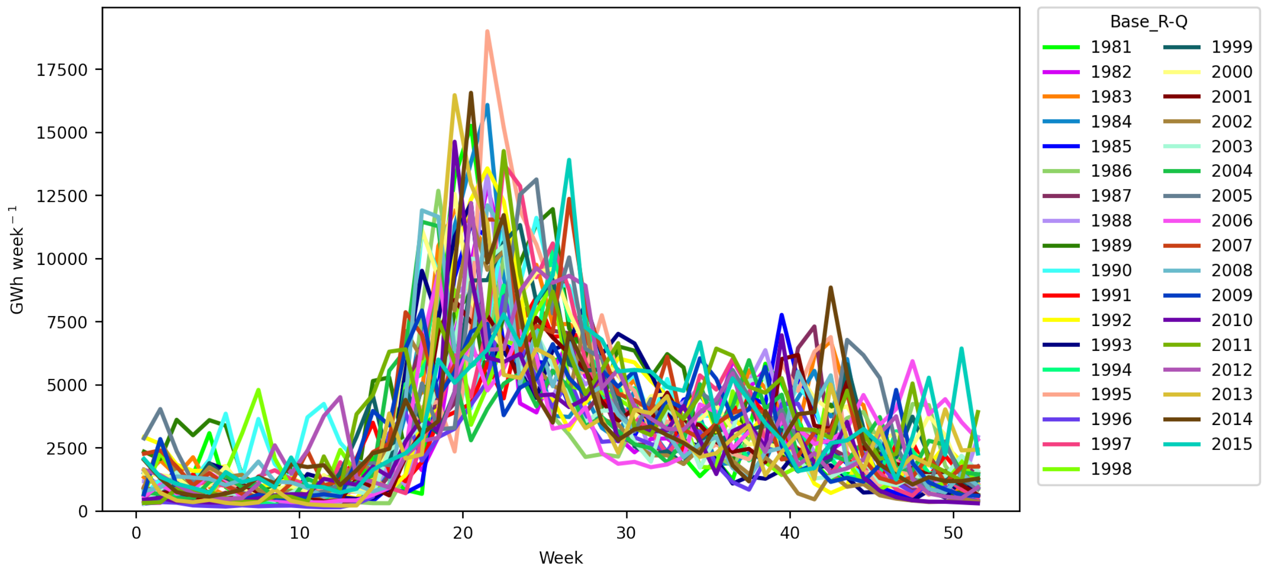

Figure 19 Total regulated and unregulated inflow to hydropower in Norway for years 1981-2015.

Other countries

No changes were made to the hydropower description for Sweden compared to the description used in HydroCen, as this aligned well with NVE's data. The hydropower in Finland is aggregated in the SumEffekt dataset. We ensured that that the total hydropower production in Finland matches the production used by NVE for Finland in 2030 (NVE 2020).

The dataset has aggregated hydropower descriptions for the Baltic region, Poland, France and the three areas in Great Britain, respectively, which were kept unchanged from the HydroCen Low Emission scenario.

5.1.2 Wind and solar

We use estimated time series for historical wind and solar power production for each model area for the simulated years 1981-2015 (Svendsen 2017). The estimations are based on meteorological NCEP Reanalysis data defined at 6-hourly time resolution and linearly interpolated to 3-hourly time resolution for the analysis with FanSi and EMPS and 1-hourly time resolution for the analysis with Primod.

Norway

We assume as default 18.1 TWh onshore wind, 1.6 TWh offshore wind and 1.8 TWh solar power production in Norway by 2030 (NVE 2020). The assumed distribution of onshore wind power capacity among regions in Norway was established based on information from NVE's database on existing turbines, projects granted license and projects under construction[3]. Solar power production was assigned the same distribution per area as in the HydroCen Low Emission scenario.

The "-HighSolar" pair of scenarios include 8 TWh solar power in Norway in 2030, based on a target set by the Norwegian Government and Parliament to have 8 TWh electricity production from solar by 2030[4]. All other scenarios have 1.8 TWh solar power in 2030.

Other countries

We assume total annual wind power production of 51 TWh, 36 TWh and 19 TWh in Sweden, Denmark and Finland, respectively (NVE 2020). Similarly, total solar power production is 2.5 TWh, 5.8 TWh and 1.0 TWh in Sweden, Denmark and Finland, respectively. We make assumptions to distribute wind and solar power production numbers for Sweden and Denmark between individual model areas within each country.

Similarly as for the Nordic countries, assumptions for wind and solar production for other countries were established based on NVE data (NVE 2020) supplemented with own assumptions and/or other sources to disaggregate into individual model areas as needed. For example, Great Britain has 117 TWh annual wind power production and 36 TWh solar power production, and Germany similarly has 189 TWh wind power and 111 TWh solar power production.

5.1.3 Thermal and nuclear

Power generation

Assumptions determining power production from thermal sources (comprising natural gas, biomass, oil and coal) and nuclear are made to ensure reasonable consistency between simulation results and NVE scenarios (NVE 2020). Norway has very little thermal power generation (1.4 TWh) and no nuclear power generation. Sweden has both substantial thermal power generation (20 TWh, coming primarily from biomass-fired power plants) and nuclear power generation (43 TWh). The dataset has three Swedish nuclear power plants all located in the model area 'Sver-Midt' (belonging to NordPool price area SE3):

[3] https://www.nve.no/energi/energisystem/vindkraft/vindkraftdata/

[4] https://www.europower.no/solenergi/flertall-pa-stortinget-om-sol-tiltak-vil-ha-8-twh-solkraft-i-2030/2-1-1466415

Forsmark, Oskarshamn 3 and Ringhals 3&4. Finland has about the same thermal power generation (21 TWh, mostly from biomass) and nuclear power generation (41 TWh) as Sweden. Denmark does not have nuclear, but has 11 TWh thermal power generation (from biomass and natural gas) according to the assumptions (NVE 2020).

Some other countries have more substantial inputs of fossil fuel-based power than the Nordic countries. For example, there is around 100 TWh of electricity from natural gas in both Germany and Great Britain. Nuclear power production amounts to around 57 TWh in Great Britain. France stands out with showing the most substantial production from nuclear, around 300 TWh.

Fuel prices

Prices for fuels and CO_2 emission allowances influence simulated electricity prices. In particular, the price of natural gas is a key factor in our simulations as gas-fired power plants generate a significant portion of Europe's electricity in 2030. CO_2 price is also important as natural gas power plants emit CO_2.

To illustrate by one calculation example, we may assume natural gas power plant efficiency 55% and CO_2 emissions 400 kg MWh^{-1}. A gas price of 30 EUR MWh^{-1} then translates into a cost of 30 / 55% = 55 EUR per MWh of electricity. Further, a CO_2 price of 100 EUR $tonne^{-1}$ translates into 100 x 0.4 = 40 EUR per MWh of electricity. Hence, in this case the total cost of generating electricity is 55 + 40 = 95 EUR MWh^{-1}.

The fuel and CO_2 prices for 2030 Base and 2030 High price scenarios respectively are shown in Table 7. We consider the base price to be the most realistic assumption for 2030, but uncertainty exists. The purpose of the High prices is to explore sensitivities of results to increased prices. Our 2030 Base and High prices for coal, natural gas and CO_2 are the same as base and high prices in (Statnett 2023). These prices are overall higher than price trajectories in (NVE 2023d) of 19 EUR MWh^{-1} for natural gas and 58 EUR $tonne^{-1}$ for CO_2. Our assumed biofuel prices are from the HydroCen Low Emission scenario (Schäffer and Graabak 2019).

Table 7 Fuel prices and CO_2 emission allowance prices used for base and high price scenarios.

Fuel or CO_2	Unit	2030 Base	2030 High price
Coal	EUR $tonne^{-1}$	90	140
Natural gas	EUR MWh^{-1}	30	40
Bio	EUR $tonne^{-1}$	30	30
CO_2	EUR $tonne^{-1}$	100	140

Start-up costs and minimum production

Start-up costs and minimum production levels are taken into consideration for individual thermal power generation units (natural gas, biomass, oil and coal). In total across the dataset, 241 thermal power plants have assigned start-up costs and minimum production levels. Yearly production profiles for nuclear are the same as in HydroCen (Schäffer and Graabak 2019), with the production during summer weeks set to 80% of nominal capacity.

Implementations of start-up costs for nuclear power were found to give not robust results using FanSi. This is related to the stage-wise decision problem solving process in FanSi, which can prevent FanSi from 'seeing' the full gains of switching on a nuclear power plant in a given decision stage. For this reason, we do not include start-up costs for nuclear power plants (there are nine such plants in total in the dataset). To still be able to represent nuclear power as mostly providing base load but at the same time also offering some degree of flexible generation, we split nuclear power generation into two parts: One part (75% of the capacity) that is assigned a very low marginal cost and thus effectively deliver power at a stable rate; and a second part (25% of capacity) delivering more flexible power at a higher cost.

Additional details for Primod modelling

The Primod model represents additional constraints for these thermal and nuclear power plants. In addition to start-up costs and minimum production levels, Primod includes ramping constraints and constraints on minimum uptime (minimum number of hours the plant must be running if turned on) and minimum downtime (minimum number of hours the plant must be off if shut down).

The minimum production and hourly ramping levels (in percent of maximum production), and minimum uptime and downtime used per fuel type in the modelling are shown in Table 8. When starting up or shutting down a thermal power plant in Primod, ramping between zero production and 5 % above minimum production is allowed in one time step.

Table 8 Input data used for the different types of thermal power plants.

Fuel type (number of plants)	Minimum production (%)	Hourly ramping (%)	Minimum uptime/downtime (h)
Bio (52)	25/50	40	8/8
Gas (151)	15/25/40/60	50	2/2
Coal/hardcoal (4)	30/40	40	8/8
Hard coal (20)	15/25/40/60	40	8/8
Lignite (1)	50	40	8/8
Oil (13)	15/25/40	50	2/2
Nuclear (9)	-	20	12/8

5.2 Power consumption

5.2.1 Consumption level

Norway and other Nordic countries

Initially in the project, levels of power consumption including relative distributions between consumption categories and model areas were established based on NVE's "Langsiktig kraftmarkedsanalyse 2020-2050" published in 2020 (NVE 2020). The information available from NVE included power consumption broken down by the categories "Household and services", "Transportation", "Industry, petroleum and data centres", "Hydrogen" and "Grid losses" for individual NordPool price areas in Nordic countries, as well as for Germany, the Netherlands, France and Great Britain.

Expectations for power consumption levels in Norway and Sweden by 2030 changed significantly during the course of the project, however. During 2021-2023, new information was made available by NVE (NVE 2023d; 2021) and Statnett (Statnett 2023; 2022) that indicate higher expected 2030 consumption levels for Norway. Similarly, publications by Svenska Kraftnät (Svenska Kraftnät 2022; 2021) indicate higher 2030 consumption for Sweden. Therefore, in a later stage of the project, we adjusted total consumption levels for Norway and Sweden upwards to obtain a representation that is more in line with current expectations. The relative distributions between consumption categories and model areas were not changed, however.

Table 9 provides an overview of power consumption broken down by price areas in Norway and Sweden for low, base and high demand scenarios (numbers are from FanSi model runs without new environmental restrictions). Also shown in the table are national power balances, which are calculated as total production minus total consumption minus total losses for Norway and Sweden respectively.

Table 9 Power consumption and power balance (calculated as production - consumption - loss) in low, base and high demand scenarios for Norway and Sweden in model runs without new environmental restrictions. Unit: TWh year^{-1}.

Area	Low demand	Base	High demand
NO1	43.5	46.7	49.8
NO2	41.6	44.1	46.8
NO3	30.7	32.9	35.1
NO4	19.7	20.8	22.0
NO5	20.7	21.9	23.2
Norway	156	166	177
Norway balance	*14*	*4.3*	*-6.1*
SE1	21.3	23.2	29.5
SE2	19.0	20.7	22.7
SE3	86.0	93.5	106
SE4	26.2	28.6	31.7
Sweden	152	166	190
Sweden balance	*31*	*21*	*2.3*

Figure 20 displays total power consumption for low, base and high demand scenarios and for Norway and Sweden. The figure is consistent with Table 9.

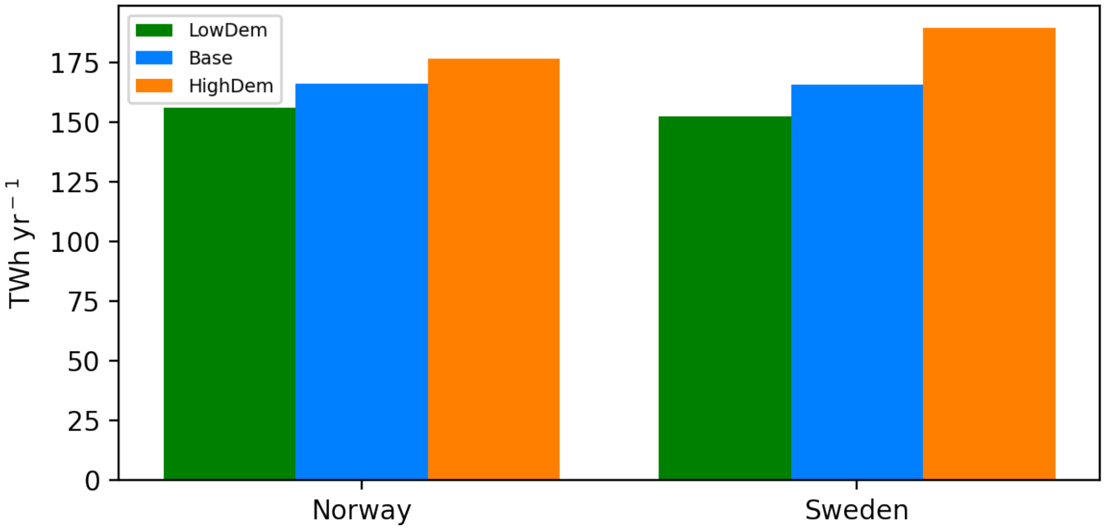

Figure 20 Total power consumption in low, base and high demand scenarios for Norway and Sweden (consistent with numbers in Table 9).

As mentioned above, data obtained from NVE included breakdowns of power consumption into NordPool price areas. To disaggregate these data into the more detailed area definitions used in the power system models, we use the same allocation key as used previously in HydroCen (Schäffer and Graabak 2019). The share of consumption allocated to each area is different for the categories "Households" and "Industry", so we use the specific allocation keys for these types of consumption. The categories for "Transport", "Hydrogen" and "Grid losses" do not exist in the HydroCen data; therefore, we use the allocation key for the total consumption for these categories.

In general, the splits into the main categories of consumption ("Households", "Industry", etc.) are roughly consistent with the information obtained from NVE. Some deviations in the relative shares for each category may occur due to adjustments necessary because of different accounting principles (e.g., of power losses at different voltage levels) and because of iterative adjustments to the data to achieve the desired level of consumption overall.

In the Nordic countries where electricity is widely used for space heating, the consumption category "Public supply" is correlated to the outdoor temperature. This is accounted for in the model by using historical temperature series and weekly correction factors (% change in consumption per degree deviation from the normal temperature) for this type of consumption in Norway, Sweden, and Finland.

Other countries

The power demands for Germany, The Netherlands, France, and Great Britain are also based on information obtained from NVE related to the "Langsiktig kraftmarkedsanalyse 2020-2050" published in 2020 (NVE 2020). For disaggregation into individual model areas for Germany and Great Britain, we use the same allocation key used in the HydroCen scenario. For yet other European countries than the ones just mentioned, we use the same assumptions for power consumption as in HydroCen (Schäffer and Graabak 2019).

5.2.2 Load profiles

NVE has shared load profiles, both week-to-week and within the week profiles, for the Nordic countries. The profiles for "Household and services" are created based on NordPool data, minus an estimate of industrial consumption with a flat profile. In addition, NVE has provided profiles for transport and electricity consumption for hydrogen production. The hydrogen profiles are based on test runs with the Thema model, and hours with a high probability for low prices.

In total, 26 profiles for within the week were added (so called "effektprofiler"): a flat profile used for industry and grid losses in the Nordics, profiles for "Household and services" per price area in Norway, Sweden, Finland and Denmark, profiles for hydrogen production for the same price areas, and one profile for electric vehicles (transport). In total, 24 week-to-week profiles were added (so called "lastprofiler"): a flat profile used for industry, transport and grid losses, profiles for "Household and services" per price area in Norway, Sweden, Finland and Denmark, and profiles for hydrogen production for the same price areas.

The load profiles for other countries in Europe were unchanged (one profile per country). These profiles originate from HydroCen (Schäffer and Graabak 2019).

5.2.3 Price-dependent demand

Some of the consumption in Norway and Sweden is modelled as price sensitive contracts (denoted "PREF" in the model). Such contracts are important for modelling demand flexibility from industry that only uses electricity when the prices are sufficiently low. For Norway, such contracts exist in most areas, and have prices ranging from 28 €/MWh to 190 €/MWh. All contracts in Norway have the same capacity throughout the year. We use the same data for these contracts as in HydroCen (Schäffer and Graabak 2019).

Other parts of the consumption in Norway, Sweden, Finland and Germany are modelled using a price-demand elasticity function. When the power price deviates from a given reference price, demand is adjusted upwards or downwards. At high prices the demand decreases, and when the prices are low, demand increases. The price elasticity factor was set to -0.025, meaning that for example for a 20% change in power price, there will be an approximately 0.5% change in demand. We set a lower limit of 7 EUR/MWh and an upper limit of 3000 EUR/MWh for this demand elasticity, where the upper limit of 3000 EUR/MWh is also the assumed rationing price.

A rationing price of 3000 EUR/MWh is assumed for all areas.

5.3 Power transmission

5.3.1 Capacities and losses

The transmission capacity assumptions between model areas are derived from a combination of previous assessments (Schäffer and Graabak 2018; 2019; Twenties 2013) and updated evaluations of current capacities, including anticipated expansions up to 2030. The updated assessments have been conducted in a joint effort with the project HydroConnect. In comparison to the capacities utilized in HydroCen, modifications of six connections were implemented, primarily involving reduced assumed transmission capacities within the Norwegian grid. These adjustments were made based on the latest available information (Nord Pool 2022; Statnett 2021a; 2021b; 2021c).

In total, the Norwegian exchange capacity with surrounding countries amounts to 9 300 MW. This includes the recently established connections linking Norway and Germany (NordLink, 1400 MW) and Norway and Great Britain (North Sea Link, 1400 MW).

Table 10 Assumed transmission capacities (MW) internal Norway.

Area 1	Area 2	→	←	Notes
OSTLAND	SOROST	2300	2300	Based on current grid and voltage upgrade "Flesakersnittet"
OSTLAND	HALLINGDAL	3900	3900	Based on current (2022) NordPool NO1-NO5 market capacities
OSTLAND	NORGEMIDT	500	500	Based on current (2022) NordPool NO1-NO3 market capacities (upgraded Aura-Vågåmo-Fåberg (Gudbrandsdalen) is not expected before 2030)
SOROST	TELEMARK	500	500	Same as in Twenties project (2013) and HydroCen FME (2018)
SOROST	SORLAND	1100	1300	
SOROST	VESTSYD	900	900	
HALLINGDAL	VESTMIDT	2000	2000	
TELEMARK	VESTSYD	900	900	
SORLAND	VESTSYD	3500	3500	
VESTSYD	VESTMIDT	1800	2000	Based on overall evaluation and ongoing/planned grid upgrades south-west Norway, including information from Statnett "Langsiktig analyse av transportkanaler 2021-2040". Assume somewhat lower capacity in direction north.
VESTMIDT	NORGEMIDT	750	750	Assume somewhat higher capacities than current (2022) NordPool NO5-NO3 market capacities of 500 MW, based on assumed somewhat lower congestion issues in 2030 compared to today
NORGEMIDT	HELGELAND	1500	1500	Based on current grid (new 420 kV Nedre Røssågå-Namsos is not expected by 2030)
HELGELAND	TROMS	1100	1100	Based on current grid and recent/planned Ofoten– Balsfjord–Skillemoen-Skaidi upgrades
TROMS	FINNMARK	950	950	

Table 11 Assumed transmission capacities (MW) Norway-abroad.

Area 1	Area 2	→	←	Notes
SORLAND	DANM-VEST	1200	1200	Assuming Skagerrak 1-2 are phased out by 2030
SORLAND	TYSK-NORD	1400	1400	NordLink
SORLAND	NEDERLAND	700	700	NorNed
VESTSYD	GB-MID	1400	1400	North Sea Link
OSTLAND	SVER-MIDT	2145	2095	Adopted from HydroCen FME scenarios (2018). Numbers are also the same as current (2022) NordPool NO1-SE3 market capacities
NORGEMIDT	SVER-NN2	1000	1000	Adopted from HydroCen FME (2018). Numbers are similar to current (2022) NordPool NO3-SE2 market capacities, but NordPool has smaller capacity (600 MW) in direction SE2=>NO3
HELGELAND	SVER-ON2	350	350	Adopted from HydroCen FME (2018). Numbers are similar to current (2022) NordPool NO4-SE2 market capacities (NordPool uses 300 MW and 250 MW)
TROMS	SVER-ON1	600	600	Adopted from HydroCen FME (2018). Numbers are similar to current (2022) NordPool NO4-SE1 market capacities (NordPool uses 600 MW and 700 MW)
FINNMARK	FINLAND	130	150	Adopted from HydroCen FME (2018)

The transmission network is modelled as a transport model with linear losses. The losses for transmission lines within the Nordics are mainly 2%, except for HVDC links having 3% loss. The losses are 1% within the European continent and for connections to offshore wind farms.

5.3.2 Ramping restrictions (for Primod)

We incorporate ramping restrictions in the analyses with the Primod model, as ramping restrictions are relevant with the hourly time resolution used in the analysis with Primod. Limiting the maximum change in power flow from hour to hour on HVDC interconnectors is an important measure for the Nordic TSOs to maintain a stable system frequency. These constraints are important to include in the modelling to limit the flexibility of the power system. The current ramping restriction of 600 MW/hour for HVDC cables was introduced in 2007 for all individual HVDC interconnectors outside the Nordic synchronous area. As more interconnectors are put into operation, the Nordic TSOs are considering if combined maximum ramping rates for several interconnectors can be more efficient, or if the quality of frequency can be maintained through other measures (Statnett 2020). The transition to a 15-minute settlement period in the day-ahead market and several other factors will decide what the acceptable ramping limits will be in the future.

What the ramping restrictions will be in 2030 is therefore highly uncertain. In lack of more knowledge, the current restriction of 600 MW/hour is added to our scenario for 2030 in the analyses with Primod. The ramping restrictions are not effective in the analyses with FanSi because of the three hourly time resolution in these analyses. At this time resolution, the constraint of 600 MW/hour translates into

1800 MW per three hours, which is higher than the transmission capacity and therefore the restriction becomes not effective.

The following HVDC interconnectors are subjected to ramping rates based on Nord Pool (2021):

- NorNed NO2-NL
- Skagerrak NO2-DK1
- Konti-Skan SE3-DK1
- Kontek GER-DK2
- SwePol SE4-PL
- Baltic Cable SE4-GER
- Storebelt DK2-DK1
- LitPol PL-LIT
- NordBalt LT-SE4
- Estlink FI-EE
- NordLink NO2-GER
- COBRAcable NL-DK1
- VikingLink DK1 - GB
- North Sea Link NO2-GBS

5.4 Reserve requirements

Reserve requirements are only implemented in the Primod model, and this section presents the requirements added for upward and downward spinning reserve capacity to the Base and Base_R-Q scenarios. The section also describes which power plants can deliver reserve capacity.

Constraints for both upward and downward spinning reserve capacity is implemented in the Primod-model, including the possibility to exchange reserve capacity between model areas by reserving up to a given fraction of the transmission capacity between these areas. The reserve capacity is allocated together with energy in a simultaneous clearing of the energy (Day-Ahead) market and reserve capacity market. Table 12 shows the demand for both upward and downward spinning reserve capacity used in this project for each price area in the Nordic power system (Haugen and Helseth 2021). In total, about 2400 MW of both upward and downward reserve capacity must be allocated in the Nordic power system, where almost 800 MW of this should be reserved in Norway. In our analysis, we allowed for up to 10% of the transmission capacity between areas to be used for exchange/sharing of reserve capacity.

Table 12 Demands for reserve capacity (both upward and downward) for each price area in the Nordic power system.

Country	Price Zone	Requirement [MW]
Norway	NO1	167
	NO2	229
	NO3	83
	NO4	146
	NO5	167
Sum		**792**
Sweden	SE1	216
	SE2	157
	SE3	354
	SE4	197
Sum		**924**
Finland	FI	**335**
Denmark	DK2	**356**
Sum		**2407**

For hydropower plants, there is a loss of efficiency when producing at levels below the best efficiency point. This is not captured in the FanSi model, where all production-discharge curves (PQ-curves) are convex. In Primod, this is handled for a selection of hydropower plants by introducing start-up variables associated with a minimum production level. The minimum production is set to 50 % of the production at best efficiency point with only 80 % of the best point efficiency. The start-up cost for each plant is estimated based on the production capacity, P, by the linear function 100 + 0.2P EUR.

Only a selection of power plants can deliver reserve capacity in the model. In areas without hydropower capacity, selected gas power plants are allowed to contribute. For hydropower, only power plants with a production capacity of 20 MW or higher and a reservoir capacity of 2 Mm^3 or higher can contribute. 186 hydropower plants in Norway fulfil this criterion, and Figure 21 shows the distribution of these plants among the price areas. The figure also shows how many of these plants are subject to different new environmental constraints. As we see, about half of the plants gets new environmental constraints in our analysis. These 186 power plants will also be subject to minimum production and start-up costs. In addition, there must be more than 1 Mm^3 available water (above zero or the minimum reservoir requirement) in the reservoir at the start of the week to be allowed to contribute (to be able to ramp up the production if needed). The initial reservoir fillings and minimum reservoir constraints will therefor affect the number of hydropower plants able to participate in the reserve capacity market for each week.

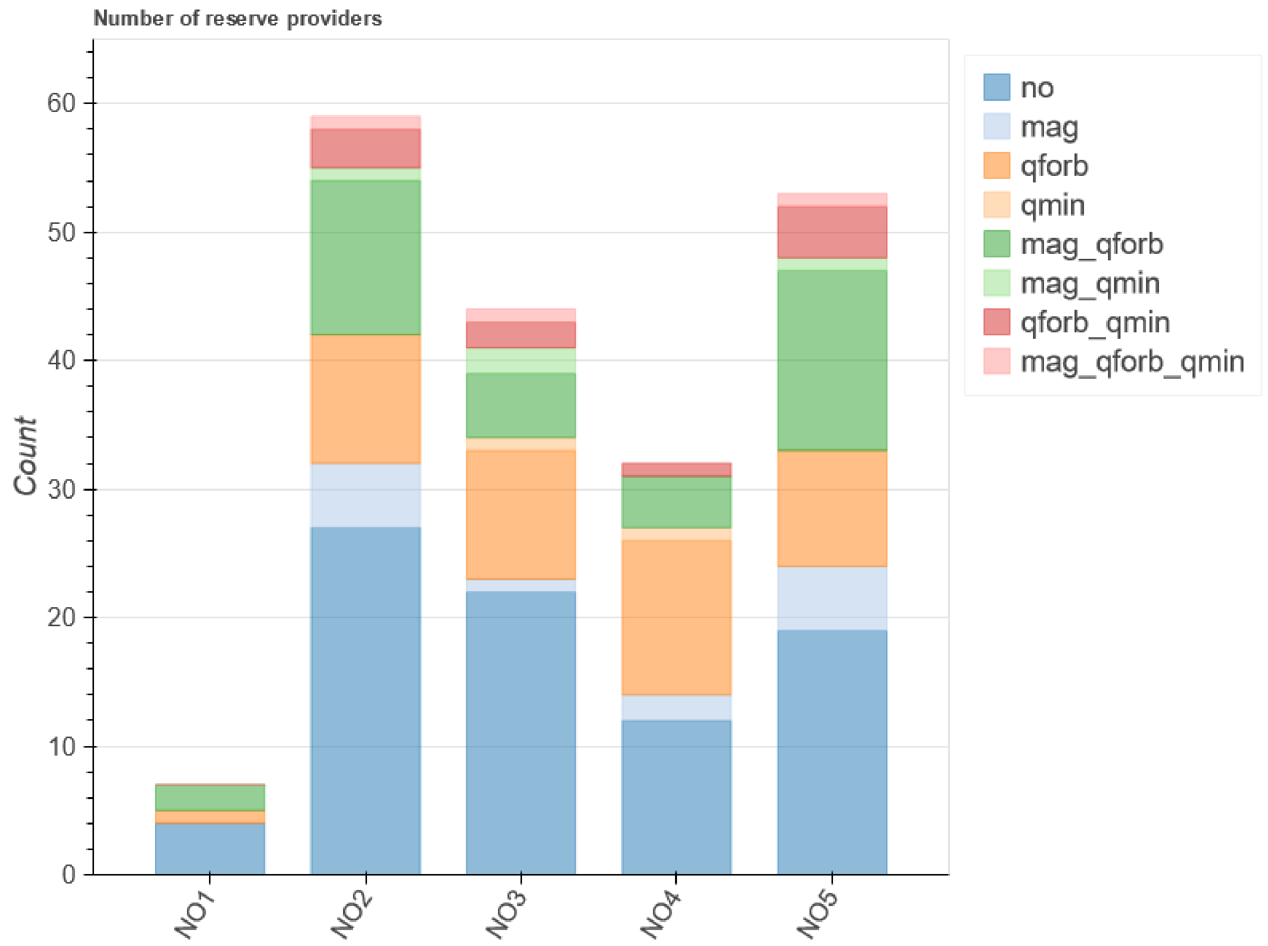

Figure 21 The number of hydropower plants delivering spinning reserve capacity for each price area in Norway. The bars are split into the number of different types of environmental constraints implemented for the power plants.

6 Results

We divide the main results presentation into seven topics: Hydropower production, power price, reservoir operation, power transmission, reserve capacity, socioeconomic surplus and specific occurrences from FanSi simulations.

6.1 Hydropower production

6.1.1 Changes in average annual production

We estimate an average annual reduction in hydropower production of approximately 3 TWh yr^{-1} for Norway as a result of new environmental restrictions, corresponding to 2% of the average hydropower production (Table 13 and Figure 22). This applies to all scenarios that represent both types of environmental restrictions (reservoir and minimum flow) calculated with default methods, irrespective of, for example, assumed levels of power demand. Specifically, FanSi estimates an average of 3.14 TWh lost hydropower production in the Base scenario, while EMPS provides a slightly lower estimate of 2.95 TWh. Different results emerge for scenarios involving different assumptions or methods for environmental restrictions (Table 13 and Figure 22), as we will discuss later in this section.

Model areas belonging to NO2 account for around one-third of the 3 TWh decrease in production (somewhat more, 40%, with EMPS). Similarly, NO5 model areas contribute slightly less than one-third. NO3 and NO4 areas make up the majority of the remaining third, while NO1 experiences more moderate production losses (Table 13).

Table 13 Average annual reduction in hydropower production (TWh yr^{-1}) following the introduction of new environmental restrictions by scenario and aggregated price area.

	Norway	NO1	NO2	NO3	NO4	NO5
Base_R-Q	3.14	0.24	1.07	0.38	0.51	0.93
Base_EMPS_R-Q	2.95	0.19	1.17	0.35	0.43	0.81
HighDem_R-Q	3.19	0.24	1.09	0.39	0.53	0.94
LowDem_R-Q	3.06	0.23	1.04	0.39	0.48	0.92
HighPrices_R-Q	3.12	0.24	1.07	0.38	0.50	0.93
HighDem_HighSolar_R-Q	3.17	0.24	1.08	0.38	0.52	0.94
Base_LowTransm	3.13	0.24	1.07	0.38	0.51	0.94
Base_R*-Q	3.65	0.26	1.22	0.44	0.54	1.20
Base_R	0.57	0.02	0.22	0.14	0.04	0.15
Base_Q	2.62	0.22	0.86	0.27	0.47	0.80
Base_R-Q*	5.34	0.35	1.91	0.57	0.96	1.54

Base_Q, which takes into consideration minimum flow requirements only, shows an average reduction of 2.6 TWh yr^{-1} because of requirements to divert flows to bypass river sections. Base_R, which considers reservoir restrictions only, exhibits an average reduced hydropower production of 0.57 TWh yr^{-1}. The reduction is attributable to higher reservoir water levels in reservoirs subject to restrictions, which in turn leads to flooding in wet summer or fall periods.

Two scenarios involving stricter interpretations of environmental restrictions experience intensified reductions compared to Base_R-Q. The reduction is 5.3 TWh yr^{-1} in Base_R-Q* where minimum bypass flow requirements are set equal to Q95, a considerably higher reduction than 3.1 TWh yr^{-1} in Base_R-Q based on our new method for estimating minimum bypass flow requirements.

Finally, the reduction in hydropower production is 3.7 TWh yr^{-1} in Base_R*-Q where both local inflow and water from upstream power plants must be accumulated in reservoirs when restrictions are active. Due to certain limitations in the technical functionality of FanSi, there is some overestimation of power loss with the stricter interpretation of reservoir restrictions; the result of 3.7 TWh yr^{-1} reduced production must therefore be considered as an upper limit.

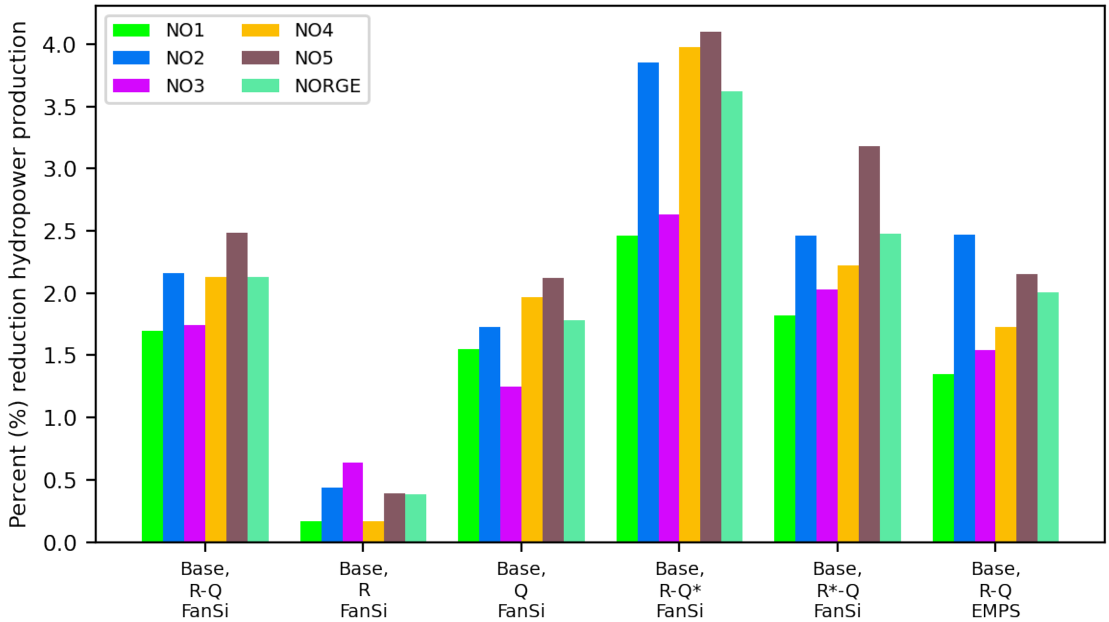

Figure 22 Average annual percent (%) reduction in hydropower production following the introduction of new environmental restrictions by scenario and aggregated price area.

In relative percentage terms, reductions in hydropower production vary somewhat across price areas. The most significant reductions relative to the average hydropower production tend to occur in NO5 with FanSi, while in EMPS results, the relative decrease in production for NO2 surpasses that of NO5 (Figure 22). The individual model area "Telemark" displays the highest reduction in relative terms. This reduction for "Telemark" amounts to close to 3.5% of the average hydropower production, compared to around 2% for the entire Norway (Figure 23).

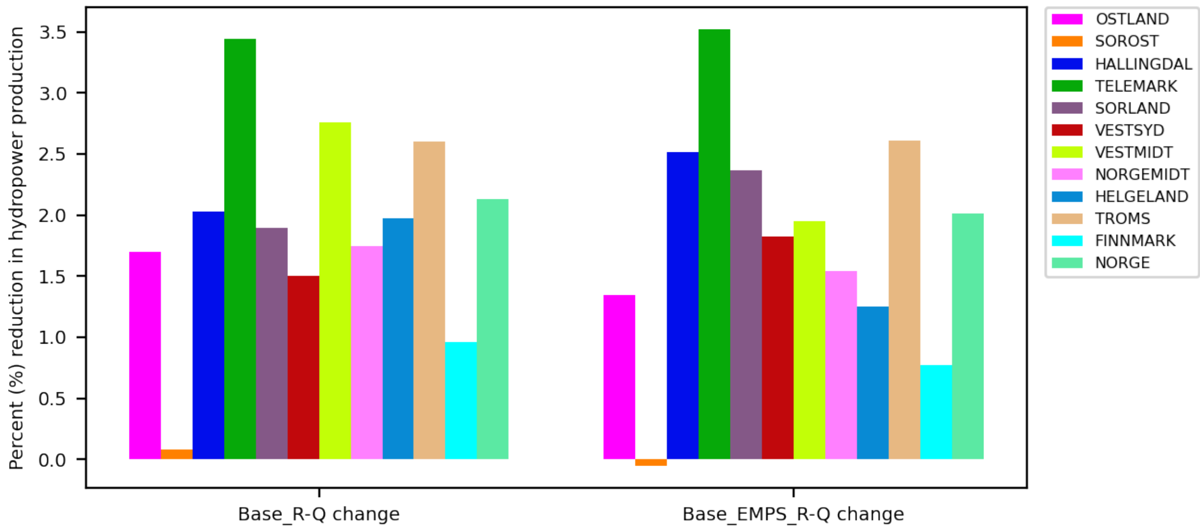

Figure 23 Average annual percent (%) reduction in hydropower production following the introduction of new environmental restrictions by scenario and individual FanSi/EMPS model area.

6.1.2 Changes in average weekly production over the year

We quantify losses as the sum of simulated bypass and flooding. These loss quantifications will on average be approximately equal to reductions in production but may differ from reductions in production during specific time periods due to the dynamics of hydropower operations. The profile of average quantified losses over the year exhibits two key characteristics (Figure 24): 1) A consistent pattern of a low level in winter and a high level in summer, in accordance with assumed seasonal bypass requirements); and 2) fluctuations resulting from stochastic flooding incidents, particularly in the summer months. These results appear similar across all R-Q scenario variants but vary when different assumptions or methods for environmental restrictions are applied (scenario variants R, Q, R*-Q and R-Q*).

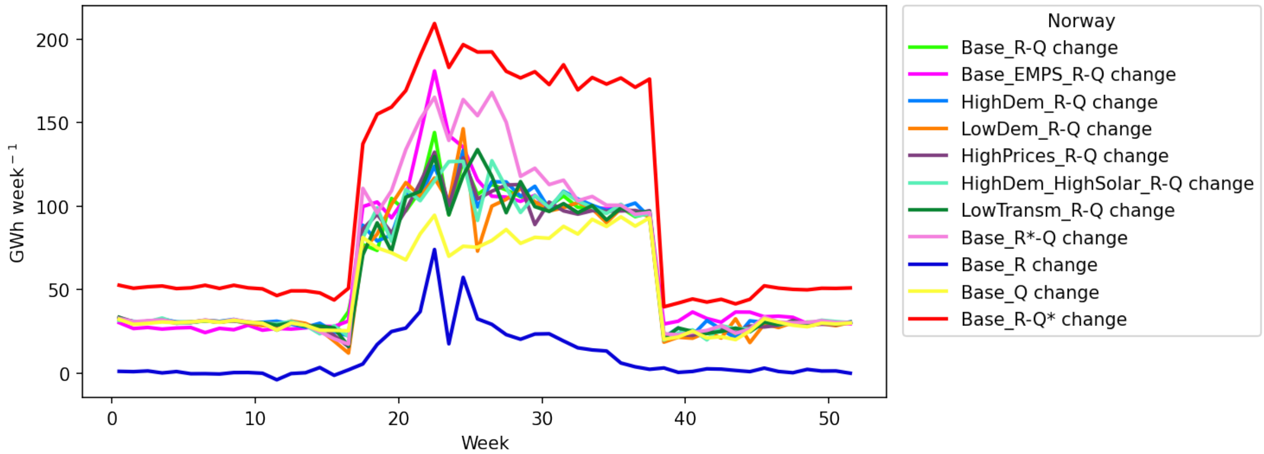

Figure 24 Average weekly power loss (sum of bypass and flooding) over the year because of the introduction of new environmental restrictions. Results are shown as totals for Norway for 11 scenarios.

When looking at the yearly profile of average changes in hydropower reduction, deviations become apparent between the results obtained from FanSi and EMPS (Figure 25). FanSi results display a noteworthy reduction in average production in weeks 18-19 due to the environmental requirements starting in week 18. This reduction is strongest for scenario Base_R*-Q which has the most stringent implementation of the reservoir restrictions. In contrast, weeks 18-19 do not clearly stand out in the average results from EMPS. Beyond weeks 18-19, the results from FanSi indicate a relatively consistent decline in hydroelectric production throughout the year, on average. Conversely, the EMPS results reveal a more distinct contrast between winter and summer months. According to EMPS results, the reduction in production is most pronounced during the winter months, with even a period of increased production on average during the mid-year. The summer increase is attributable to fuller reservoirs in the simulations.

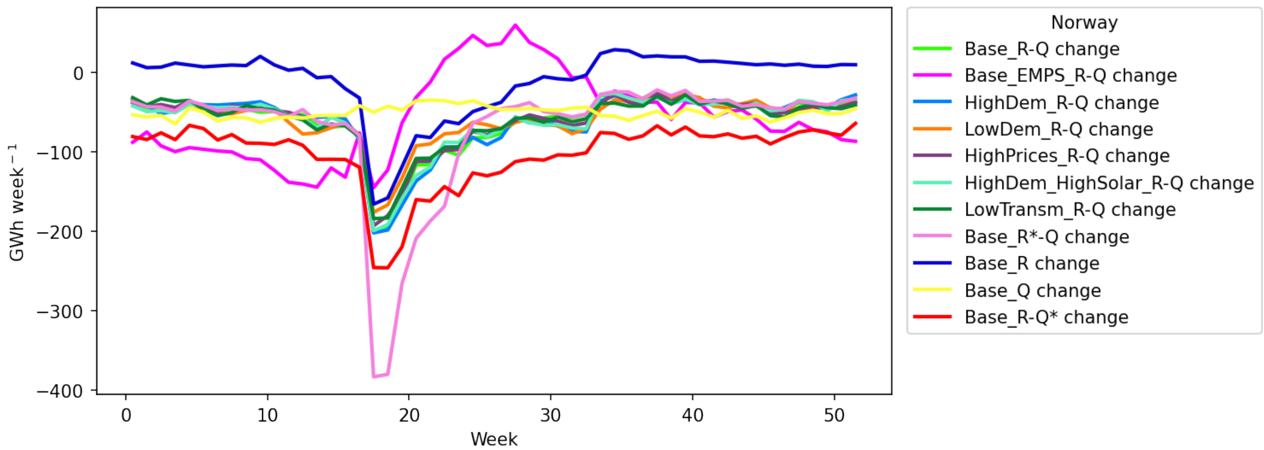

Figure 25 Average weekly change in hydropower production over the year because of the introduction of new environmental restrictions. Results are shown as totals for Norway for 11 scenarios.

Two examples illustrate potential impacts of reservoir restrictions on hydroelectric production from individual power plants: 1) Tysso II power plant in the "Vestsyd" model area exhibits reduced production for a period starting from week 18 due to a reservoir restriction placed on this power plant in our analysis. Meanwhile, production tends to increase in other parts of the year, especially during the winter and spring before week 18. 2) In the case of Songa power plant in the "Telemark" model area, production is completely halted for a period starting from week 18 due to a reservoir restriction placed on this power plant in our analysis[5]. The reason why production is reduced to zero in this case, is that Songa is the top reservoir in its watercourse. Consequently, it lacks the ability to draw water from upstream power plants to sustain production during the reservoir restriction. Tysso II, on the other hand, receives water from power plants upstream and can utilize this water for production even when the restriction is in effect.

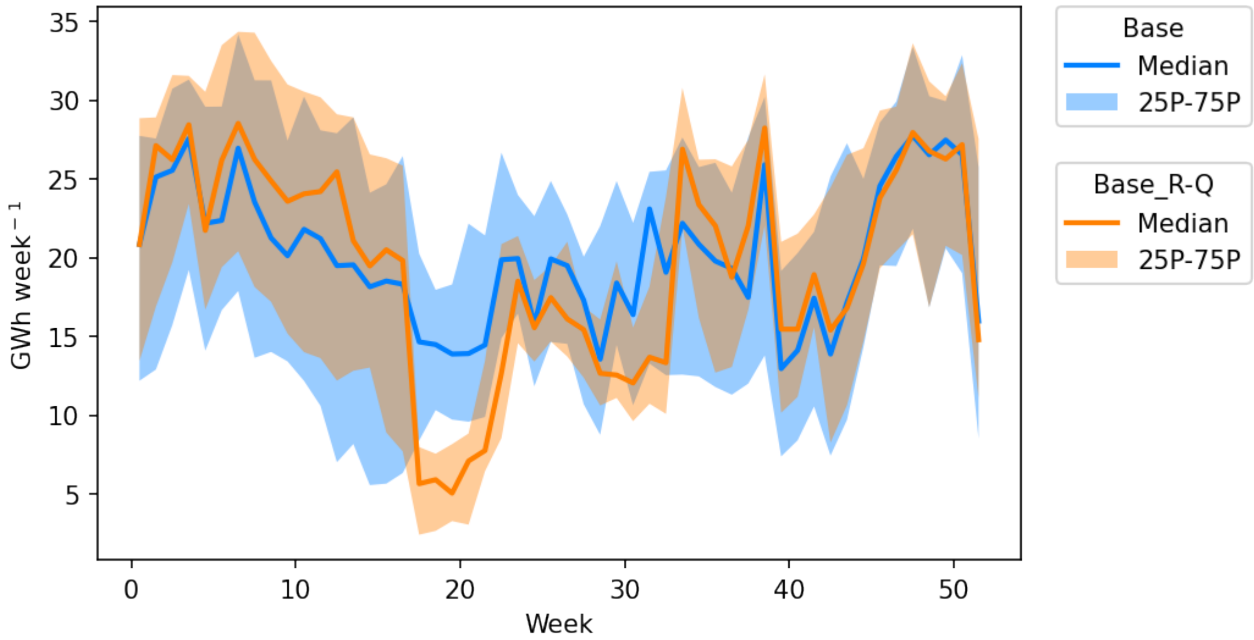

Figure 26 Weekly average power production for Tysso II power plant in model runs without ("Base") and with ("Base_R-Q") new environmental restrictions. Solid lines represent medians and shaded areas interquartile ranges (25-75 percentiles) for 35 simulated weather years.

[5] During the project, the formal revision of terms for lake Songavatn (represented as module "Songa" in FanSi) was published and did not include a reservoir restriction. However, we retain the example here for illustration.

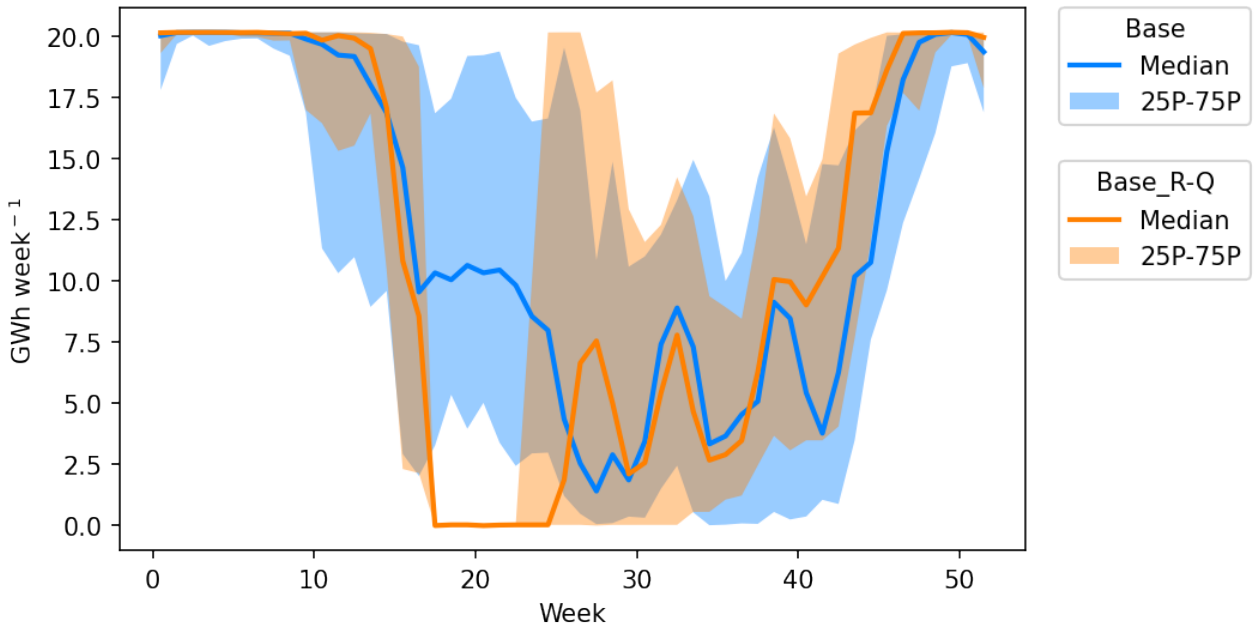

Figure 27 Weekly average power production for Songa power plant in model runs without ("Base") and with ("Base_R-Q") new environmental restrictions. Solid lines represent medians and shaded areas interquartile ranges (25-75 percentiles) for 35 simulated weather years.

6.2 Power price

This section presents findings concerning power prices. At the outset, however, it is useful to note one caveat to the simulations with FanSi, namely that we judge simulated power prices occurring in weeks 15-16 in 1986 to be overly influenced by unrealistically low aggregate reservoir levels. For this reason, we exclude this specific two-week period from calculations of average price values in a consistent manner across all scenarios. In short, the low reservoir levels come about as a result of formal mathematical optimization without user input or subjective risk assessment in FanSi as configured in this project. For a more detailed discussion, see the later Section 7.6.

6.2.1 Changes in total average prices

The new environmental restrictions result in a steady and slight increase in electricity prices in most simulated periods. The results yield an average increase in electricity price is 1-2 EUR MWh^{-1}, equivalent to 1-2%, when considering all R-Q scenarios and excluding a single period with unrealistic results as explained above. The increases in average electricity prices show limited variability depending on scenario assumptions related to electricity consumption and production, fuel and CO_2 prices, and transmission, as reflected in the just-mentioned range 1-2% (or 1-2 EUR MWh^{-1}). The estimated average changes in power prices across scenarios and price areas are detailed in Table 14, Table 15 and Figure 28.

The predominant factor contributing to the rise in the average electricity price in R-Q scenarios is the minimum bypass requirements (Q), with reservoir restrictions (R) playing a much smaller role. This conclusion emerges from a comparison of results for Base_R-Q, Base_R and Base_Q, demonstrating that the bypass requirements exert a more significant influence on average price increases. The conclusion is further supported by the amplified increase in average power price observed in the alternative scenario Base_R-Q* (involving stricter bypass requirements) compared to the default scenario Base_R-Q (Table 15, Figure 28).

EMPS results show a somewhat higher average increase because of environmental restrictions than FanSi; we observe a 2.1% increase with EMPS compared to 1.4% with FanSi (Table 15, Figure 28). The explanation for the higher average price increase with EMPS lies in a reinforced increase with EMPS compared to FanSi for most simulated periods. At the same time, this effect is moderated by the fact that EMPS, unlike FanSi, show reductions in electricity prices when prices are initially low, as will be discussed later in relation to Figure 29 and Figure 30.

Table 14 Average change in power price in units of EUR MWh^{-1} following the introduction of new environmental restrictions by scenario and aggregated price area. One single period with unrealistic results is excluded from the calculation of average values. Change > 0 means a price increase.

	Norway	NO1	NO2	NO3	NO4	NO5
Base_R-Q	1.16	1.20	1.05	1.19	1.18	1.24
Base_EMPS_R-Q	1.71	1.81	1.64	1.75	1.51	1.77
HighDem_R-Q	1.35	1.45	1.10	1.42	1.42	1.49
LowDem_R-Q	1.33	1.38	1.32	1.29	1.28	1.39
HighPrices_R-Q	1.12	1.16	1.04	1.12	1.1	1.21
HighDem_HighSolar_R-Q	1.14	1.22	0.99	1.16	1.12	1.27
Base_LowTransm	1.29	1.36	1.18	1.30	1.26	1.41
Base_R*-Q	1.35	1.38	1.23	1.38	1.38	1.43
Base_R	0.24	0.23	0.19	0.25	0.33	0.24
Base_Q	1.13	1.14	1.00	1.23	1.15	1.17
Base_R-Q*	2.17	2.22	1.99	2.25	2.19	2.26

Table 15 Average change in power price in percent (%) following the introduction of new environmental restrictions by scenario and aggregated price area. One single period with unrealistic results is excluded from the calculation of average values. Change > 0 means a price increase.

	Norway	NO1	NO2	NO3	NO4	NO5
Base_R-Q	1.44	1.45	1.30	1.49	1.50	1.54
Base_EMPS_R-Q	2.07	2.15	1.99	2.13	1.89	2.15
HighDem_R-Q	1.49	1.56	1.22	1.56	1.59	1.66
LowDem_R-Q	1.86	1.89	1.81	1.84	1.86	1.94
HighPrices_R-Q	1.18	1.20	1.09	1.19	1.20	1.28
HighDem_HighSolar_R-Q	1.29	1.35	1.14	1.30	1.28	1.45
LowTransm	1.63	1.68	1.48	1.64	1.65	1.78
Base_R*-Q	1.67	1.68	1.51	1.72	1.77	1.78
Base_R	0.29	0.28	0.23	0.32	0.42	0.30
Base_Q	1.40	1.39	1.23	1.53	1.47	1.45
Base_R-Q*	2.68	2.70	2.46	2.81	2.80	2.82

Table 16 Average power price in in units of EUR MWh^{-1} by scenario and aggregated price area. One single period with unrealistic results is excluded from the calculation of average values.

	Norway	NO1	NO2	NO3	NO4	NO5
Base	80.8	82.3	81.1	80.0	78.2	80.4
Base_EMPS	82.6	84.2	82.8	82.1	79.9	82.0
Base_EMPS_R-Q	84.3	86.0	84.4	83.9	81.4	83.8
Base_Q	81.9	83.4	82.1	81.2	79.3	81.5
Base_R	81.0	82.5	81.3	80.2	78.5	80.6
Base_R*-Q	82.1	83.6	82.3	81.4	79.5	81.8
Base_R-Q	81.9	83.5	82.2	81.2	79.3	81.6
Base_R-Q*	82.9	84.5	83.1	82.2	80.3	82.6

HighDem	90.9	92.8	89.5	91.4	89.2	90.2
HighDem_HighSolar	88.6	90.2	87.3	89.1	87.4	87.7
HighDem_HighSolar_R-Q	89.7	91.4	88.2	90.3	88.5	89.0
HighDem_R-Q	92.2	94.2	90.6	92.8	90.6	91.7
HighPrices	95.1	96.8	95.5	94.1	92.1	94.6
HighPrices_R-Q	96.2	98.0	96.6	95.2	93.2	95.8
LowDem	71.7	73.1	72.8	70.3	68.7	71.6
LowDem_R-Q	73.1	74.5	74.1	71.6	70.0	73.0
LowTransm	79.6	81.2	79.9	78.8	76.8	79.2
LowTransm_R-Q	80.9	82.6	81.1	80.1	78.1	80.6
Base	80.8	82.3	81.1	80.0	78.2	80.4
Base_EMPS	82.6	84.2	82.8	82.1	79.9	82.0
Base_EMPS_R-Q	84.3	86.0	84.4	83.9	81.4	83.8
Base_Q	81.9	83.4	82.1	81.2	79.3	81.5

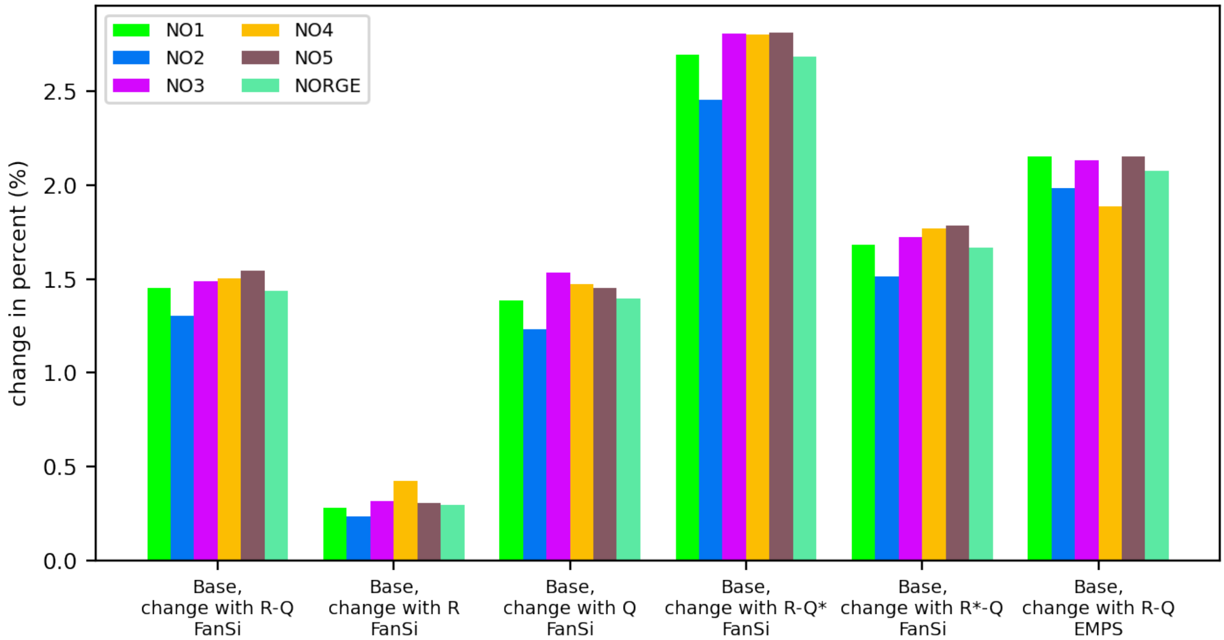

Figure 28 Average change in power price in percent (%) following the introduction of new environmental restrictions by scenario (one group of columns per scenario) and aggregated price area (individual columns). One single period with unrealistic results is excluded from the calculation of average values. Change > 0 means a price increase.

For all the results as shown in Table 14-Table 16 and Figure 28, results appear relatively similar across regions in Norway; this holds true for all scenarios and for both FanSi and EMPS. As can be seen from Figure 28, The average percentage increase in power price is smallest for NO2 (except for in the EMPS results where it is second smallest). Across all simulations, the individual model area "Sorland" – which is a part of the aggregated area NO2 – exhibits the smallest average percentage increase in power price. We interpret this as being a consequence of the international connections for Sorland (comprising connections to Denmark, Germany and The Netherlands), which probably dampen price increases in the simulations.

This conclusion appears consistent with a comparison of results between Base, LowDem and HighDem, which indicates that the factor leading to lower average price increases for Sorland/NO2 becomes stronger when the power balance for Norway becomes tighter (note for example from Table 15 that NO2 stands out rather clearly from the other areas in HighDem, but not so clearly in LowDem).

6.2.2 Price duration curves and other similar information

Price duration curves for the full 0-100% range and the top 0-0.12% range of simulated electricity prices at three-hourly time resolution reveal a few outlying instances with exceptionally high prices in the simulations (Figure 29a and b, depicting FanSi results from scenario Base). As previously in this section, we exclude these exceptional results from calculations of average effects. This exclusion specifically applies to the top 0-0.11% range of prices and is performed consistently across all scenarios. In the most extreme of the exceptional results, electricity prices align with the predefined rationing price of the model of 3000 EUR MWh^{-1}. Large reductions in simulated electricity prices because of environmental restrictions can be observed for some of these instances in the results from FanSi (Figure 29a and b).

Apart from the most extreme calculated price levels where prices decrease due to environmental restrictions as shown in Figure 29b, there is a tendency for the next highest prices to increase because of environmental restrictions. This is evident from Figure 29c and to some degree Figure 29d, showing FanSi results for scenario Base. We observe qualitatively similar increases in the next highest prices also in other results from FanSi, including in LowDem, HighDem, HighPrices and LowTransm scenario cases. The increases to the next highest prices as illustrated by Figure 29c typically occur in week 18 or the next few weeks, but may also occur in other weeks. In the cases where they occur in week 18 or shortly after, we attribute them primarily to the activation of reservoir restrictions in week 18, with minimum bypass flow requirements increasing in week 18 potentially also playing a role.

When we turn to the price duration curves obtained from EMPS, we observe that the shape of the curve for the full range of results resembles that of FanSi results (compare Figure 30a based on EMPS with Figure 29a based on FanSi). However, unlike for FanSi, EMPS suggests that environmental restrictions tend to exacerbate the very highest calculated price levels (Figure 30b). These effects occur in week 18 or in earlier spring or winter weeks and we interpret them as attributable to the reservoir restrictions that come into effect in week 18. These specific results are significantly influenced by the rationing price of 3000 EUR MWh^{-1} set in the model.

For both FanSi and EMPS with only slight differences, the new environmental restrictions result in a steady and slight increase in electricity prices in most simulated periods, as illustrated by Figure 29e and Figure 30e. With FanSi, we observe a slight tendency for the lowest prices to become even lower with environmental constraints, as is just possible to observe for scenarios Base and Base_R-Q in Figure 29f. In the corresponding EMPS simulations, this effect is much more pronounced, as is clear from Figure 30f. This effect is associated with reservoir restrictions leading to larger reservoir volumes when the system enters periods of heavy rainfall in the summer or autumn. The effect appears not to be related to the minimum flow requirements, and the effect is absent when only minimum flow requirements are analyzed (Base_Q).

Figure 31 offers a different perspective by considering, for each three-hourly time stage in the simulations, the change in power price as a result of the environmental restrictions versus the power price without the restrictions. For example, when analyzing the effects of restrictions in the Base_R-Q scenario, the horizontal axis is determined by the values in the Base scenario, while the vertical axis represents the differences between Base_R-Q and Base at corresponding time intervals. The visualization encompasses 11 scenario pairs (such as Base and Base_R-Q), 35 years with 2912 three-hourly time steps per year, and 11 model areas. This yields a total of 12.3 million data points. Simulated power prices occurring in weeks 15-16 in 1986 are omitted from the figure for the reasons provided earlier in this section. An alternative version of the figure including weeks 15-16 in 1986 is provided in the Appendix.

Figure 31 predominantly features data points concentrated within a limited area of the plot, characterized by power price values ranging from approximately 70 to 100 EUR MWh^{-1} on the horizontal axis and change in power price values spanning from around 0.5 to 2 EUR MWh^{-1} on the vertical axis. The dense clustering of these data points inhibits observation of all data points in this limited area. However, the primary objective of this figure is to highlight and emphasize outliers or extreme values. One observation is the predominance of data points from EMPS in roughly the upper left part of the figure, revealing that the most extreme price increase effects occur in the EMPS simulations. In addition, the figure reveals a scarcity of data points from FanSi exhibiting price increases when prices are initially high. Among the scenarios from FanSi model runs, the most extreme price increase effects tend to be associated with the HighDem or HighDem_HighSolar scenarios.

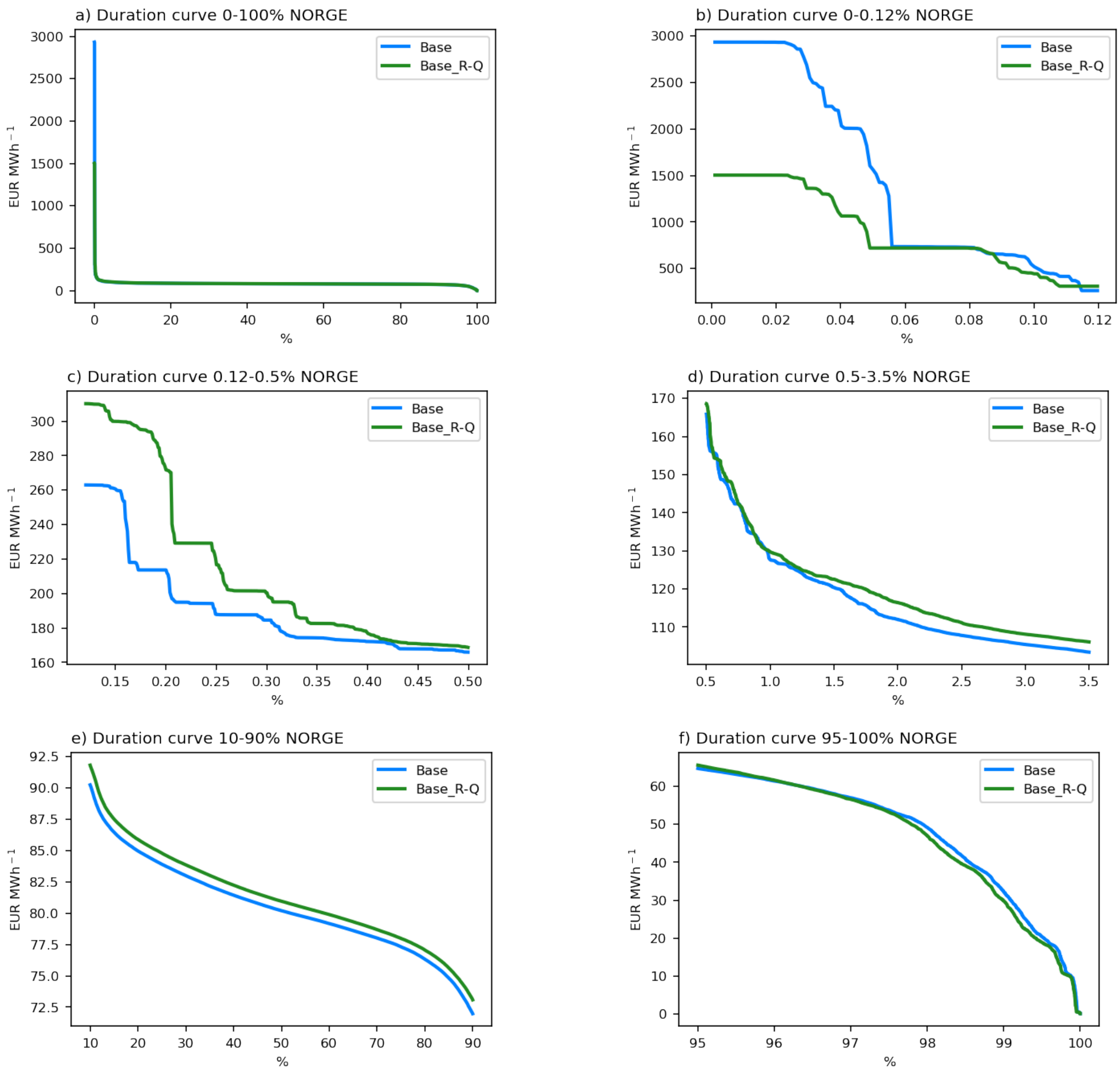

Figure 29 Price duration curve for the a) 0-100%, b) 0-0.12%, c) 0.12-0.50% , d) 0.50-3.5%, e) 10-90% and f) 95-100% range of simulated electricity prices at three-hourly time resolution in Base and Base_R-Q. Aggregate results for Norway are shown, but results are not materially different for individual areas.

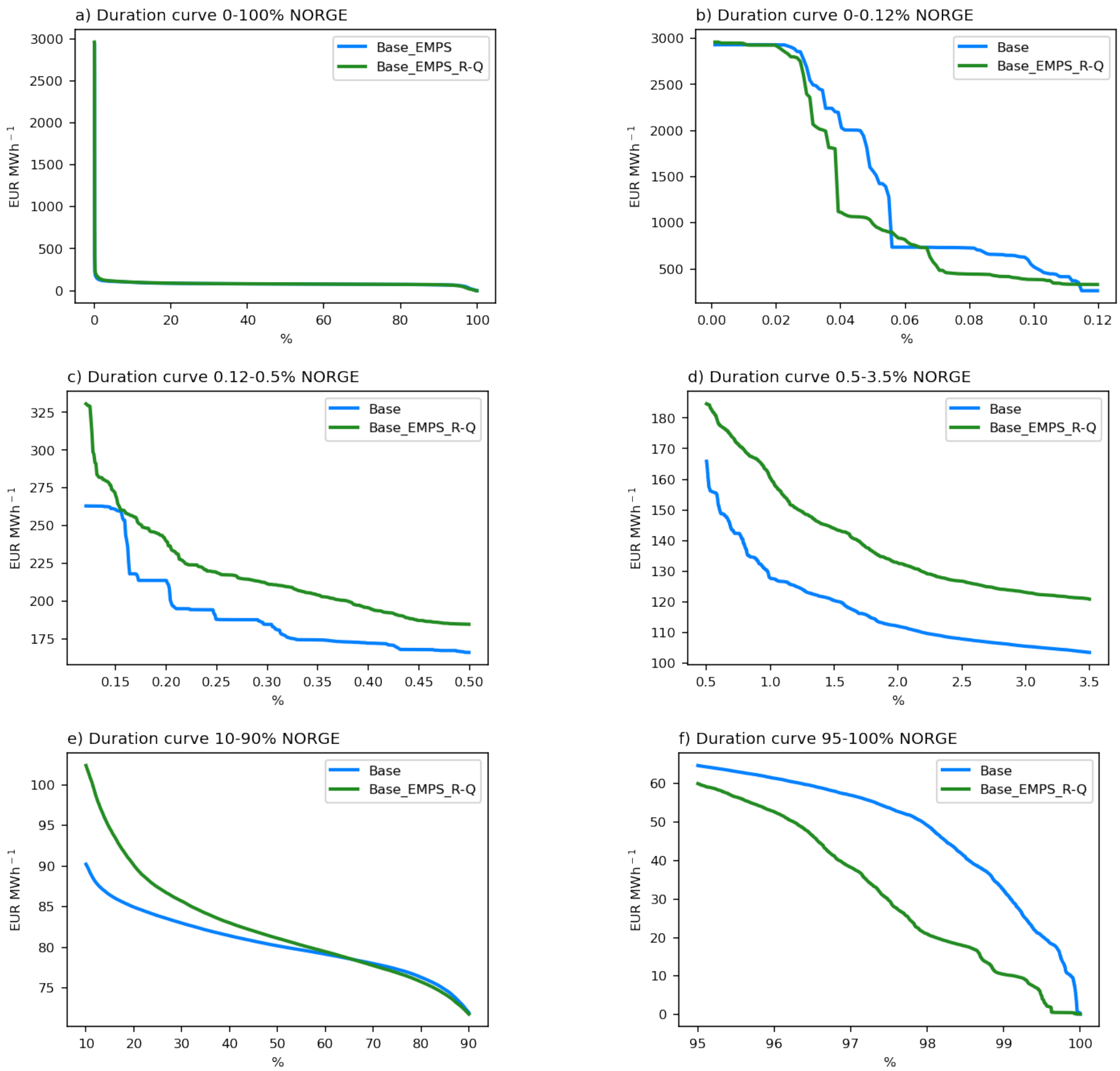

Figure 30 Price duration curve for the a) 0-100%, b) 0-0.12%, c) 0.12-0.50% , d) 0.50-3.5%, e) 10-90% and f) 95-100% range of simulated electricity prices at three-hourly time resolution in scenarios Base_EMPS and Base_EMPS_R-Q. Aggregate results for Norway are shown, but results are not materially different for individual areas.

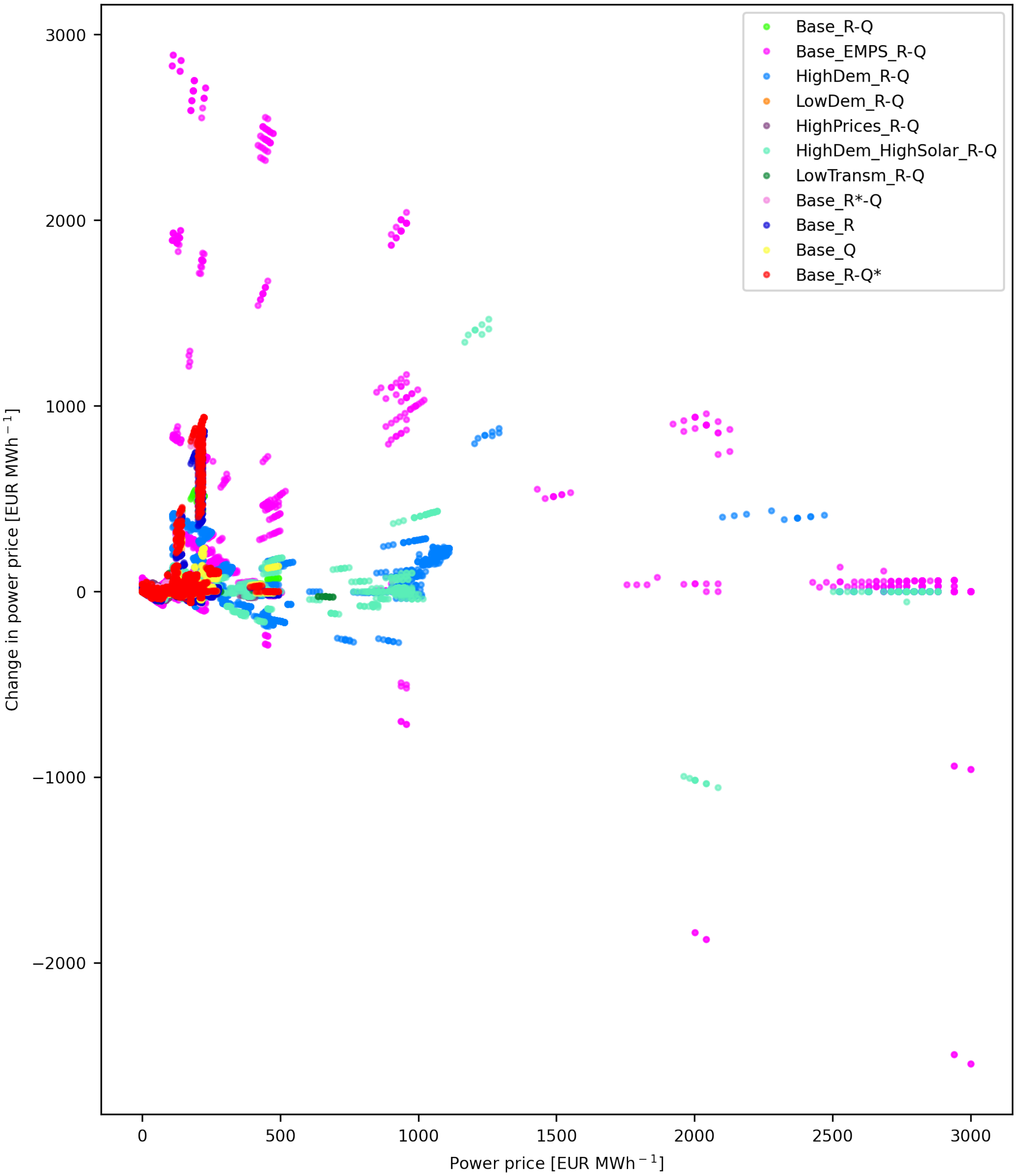

Figure 31 Change in power price as a result of the environmental restrictions (vertical axis) versus the power price without the restrictions (horizontal axis) broken down by eleven scenario pairs (e.g., Base and Base-R-Q). As we explain in the main text, there are 12.3 million data points. However, note that very many data points overlap with each other in a densely populated area below around 100 EUR MWh^{-1} on horizontal axis and between around 0.5 to 2 EUR MWh^{-1} on the vertical axis. Week 15-16 in year 1986 is excluded because of unrealistic results (see main text for explanation).

6.2.3 Changes in prices over the year

The yearly profiles of changes in power price appear different depending on whether we look at FanSi or EMPs model results. Results from FanSi indicate a relatively steady increase in the weekly prices throughout the year except for a particularly strong increase in weeks 18-19 due to the environmental restrictions coming into effect in week 18, as Figure 32 shows based on differences between Base_R-Q and Base. The pronounced increase in weeks 18-19 is attributable to the reservoir restrictions (not to bypass requirements), as Figure 69 and Figure 70 in Appendix A.3 show. On the other hand, results from EMPS tend to show higher prices in winter and lower prices in summer months (Figure 33).

These differences between simulated prices of FanSi and EMPS reflect differences observed previously for hydropower production, with FanSi showing a relatively steady decrease in production over the year except an intensified reduction around 18, and EMPS showing the strongest decrease in production during winter (Section 6). In consistency with results presented previously in Table 5-Table 7 and Figure 16, results depicted in Figure 32 and Figure 33 appear similar across price areas.

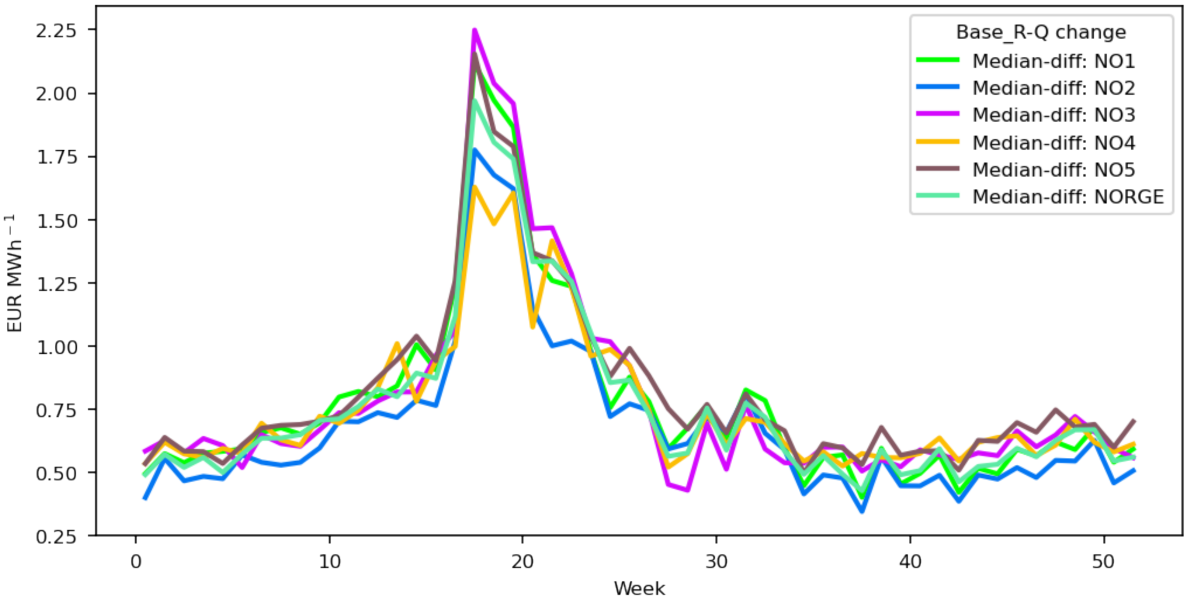

Figure 32 Change in weekly power price with environmental restrictions (R-Q) over the year with scenario Base and model FanSi. Change is calculated by first determining the difference between results from model runs with and without restrictions, and then taking the median of differences across all years. Value > 0 means price increase; value < 0 means price decrease.

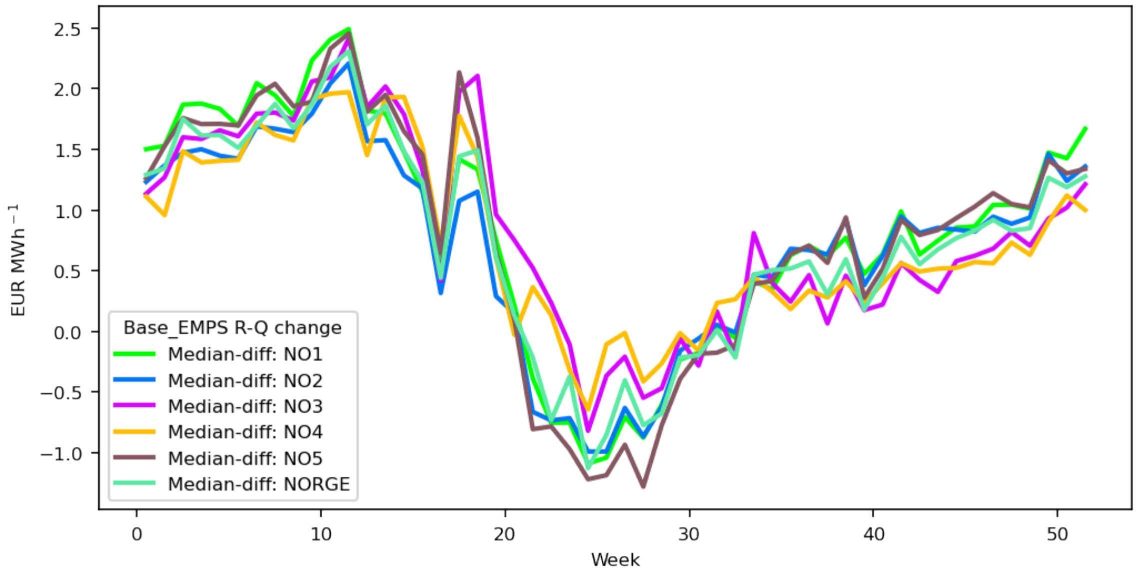

Figure 33 Change in weekly power price with environmental restrictions (R-Q) over the year with scenario Base and model EMPS. See caption to Figure 32 for further explanation.

In the simulation results at a three-hourly resolution and for individual years, both price increases and price decreases can occur at any time throughout year. At the same time, significant price increases are most commonly observed before week 20 and significant price decreases roughly between week 22 and 50. This overall pattern is consistent across FanSi and EMPS results, but is clearest in the EMPS case (Figure 34 and Figure 35).

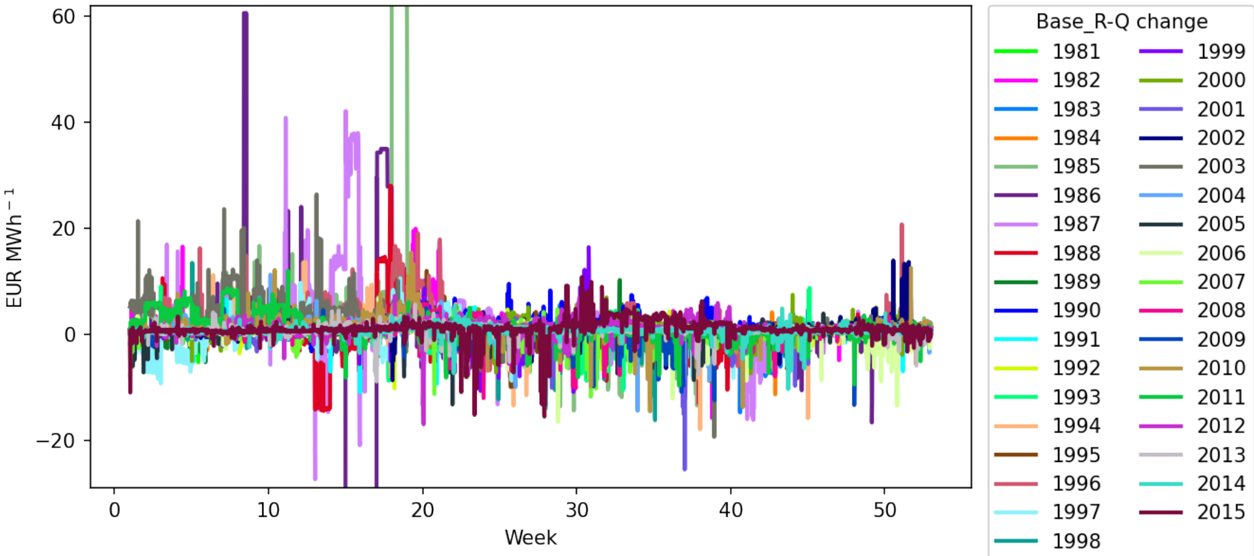

Figure 34 Change in power price over year plotted for each time three-hour time step for each year simulated with FanSi. Both positive and negative vertical axes are cut; the 1985 curve extends to around 500 EUR MWh^{-1} on positive axis, the 1986 curve extends to around -1400 EUR MWh^{-1} on negative axis.

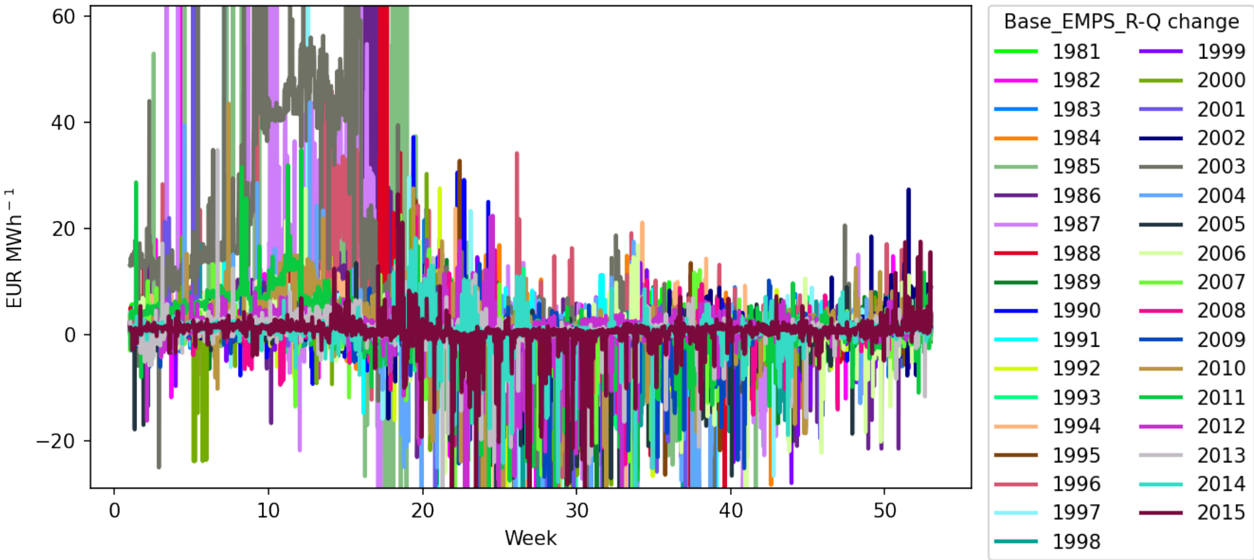

Figure 35 Change in power price over year plotted for each time three-hour time step for each year simulated with EMPS. Both positive and negative vertical axes are cut in the same way as for Figure 35 to allow for comparison between the two figures.

6.3 Reservoir operation

While the primary aim of this section is to assess the impact of new environmental restrictions on reservoir operations, it is instructive to first consider key characteristics of reservoir filling simulations using FanSi or EMPS irrespective of new restrictions. Such results for reservoir fillings are presented in Section 6.3.1.

6.3.1 Differences in reservoir operation between FanSi and EMPS

Simulated reservoir fillings from model runs conducted without the new restrictions are displayed in Figure 36 (for scenario Base using the FanSi model and scenario Base_EMPS using the EMPS model). The main purpose of this figure is to highlight that FanSi, as configured in this project, exhibits a more aggressive drawdown of the reservoirs compared to historical observations.

The lowest reservoir filling we observe in scenario Base is 1%, which occurs in weeks 15-17 in the year 1986 (Figure 36). Similarly low levels are obtained also for other years, as indicated by the 5th percentile trend for Base in Figure 36 and the individual year curves in Figure 37. As previously noted in Section 6.2, such exceptionally low reservoir occupancy levels are unrealistic. By comparison, in the past twenty years, the Norwegian Water Resources and Energy Directorate (NVE) statistics show that the lowest aggregate reservoir filling for any given week has been 18% (NVE 2023b). Furthermore, for week 16 in the simulation results for scenario Base, the 25th percentile value is 6.7% and the median is 19%, illustrating a systematic pattern of relatively low reservoir fillings before the spring snowmelt in the FanSi simulations. EMPS, on the other hand, produces an aggregated reservoir management before the snowmelt period that aligns better with observations (Figure 36).

The low reservoir levels in FanSi simulations result from formal mathematical optimization without user input or subjective risk assessment in FanSi as configured in this project. In contrast, EMPS relies more on user input and experience-based heuristics. (For a more detailed discussion, see Section 7.6.)

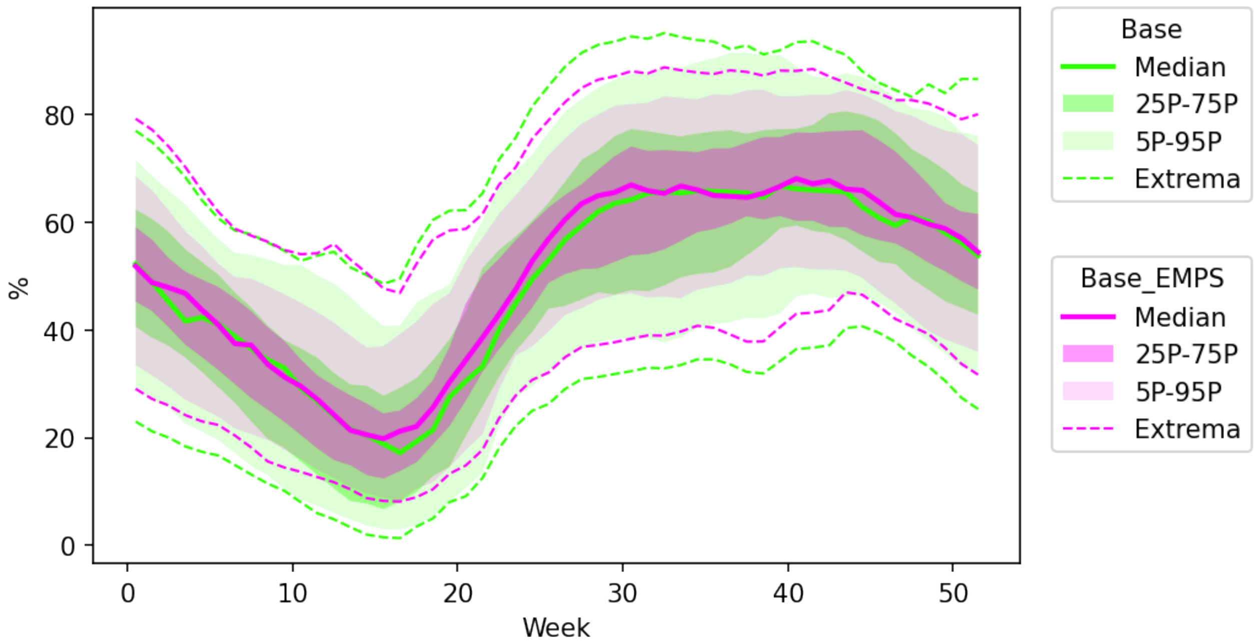

Figure 36 Simulated aggregated reservoir fillings for Norway in scenario Base (using FanSi model) and Base_EMPS (using EMPS model) respectively. Results are measured as percentage (%) of maximum reservoir capacity. Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

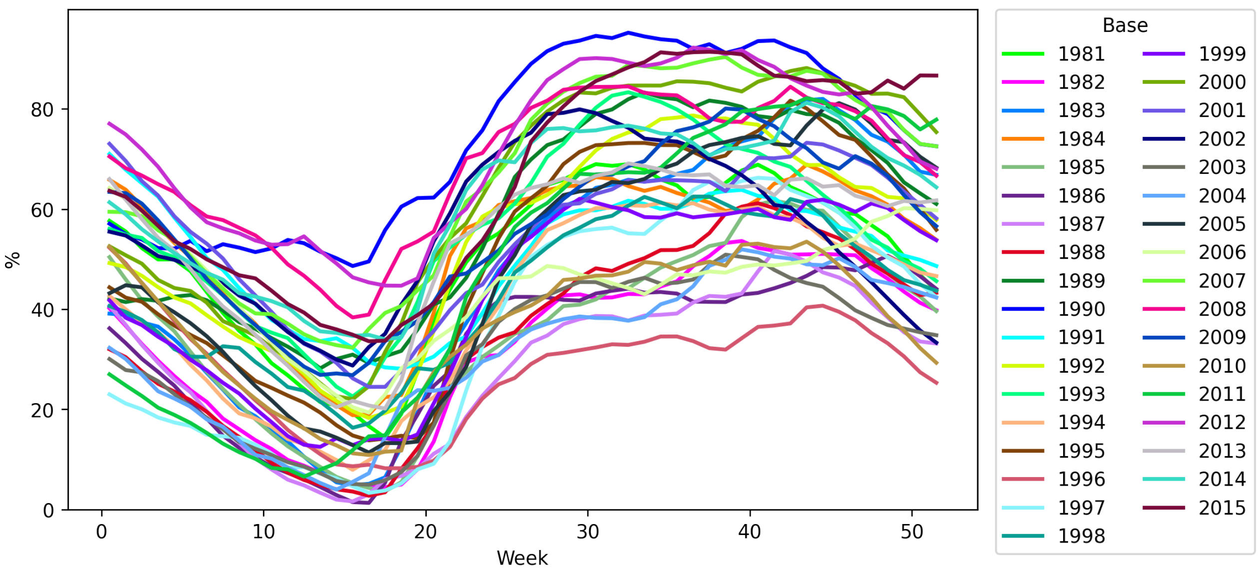

Figure 37 Simulated aggregated reservoir fillings for Norway in scenario Base (using FanSi model) for 35 individual weather years. Results are measured as percentage (%) of maximum reservoir capacity. A corresponding figure for scenario Base_EMPS (using EMPS model) is available in Appendix A.

6.3.2 Changes in reservoir operation due to new restrictions

The simulation results illustrate how environmental requirements impact the management of individual water reservoirs. Reservoirs subject to new restrictions generally undergo a change towards more accumulation of inflow during the spring snowmelt flood, resulting in more rapid rises in water levels. The low percentiles of reservoir fillings (corresponding to dry years) tend to be more affected than high percentiles (corresponding to wet years), because in the latter case, water tends to accumulate also without environmental restrictions, whereas in the former case, water accumulation replaces power production to a greater extent. We typically observe the opposite effect for reservoirs that do not face new restrictions, where reservoir fillings tend to decrease. This indicates a redistribution of water across reservoirs within river systems in response to new environmental restrictions.

Figure 38 and Figure 39 present an illustrative example from Tyssovassdraget water system within the model area "Vestsyd". We consider two modules defined in the model dataset: First, one module representing the lake Langevatn. This module is assigned a new reservoir restriction in our analysis. Second, a module representing the Håvardsvatna dams that supply water to Langevatn. The Håvardsvatna module also constitutes the top reservoir of the modelled water system. This module does not face new restrictions in our analysis. As depicted in the figures, reservoir fillings for the Langevatn module increase more rapidly in connection to the spring snowmelt flood in the model run with new restrictions, and this holds especially true for low percentile fillings. In contrast, the Håvardsvatna module shows slower increase in reservoir fillings in the model run with new restrictions. We attribute both these effects primarily to the new restriction for the Langevatn module. (We expect that other changes in the water course and wider power system to a lesser degree influence these specific results.)

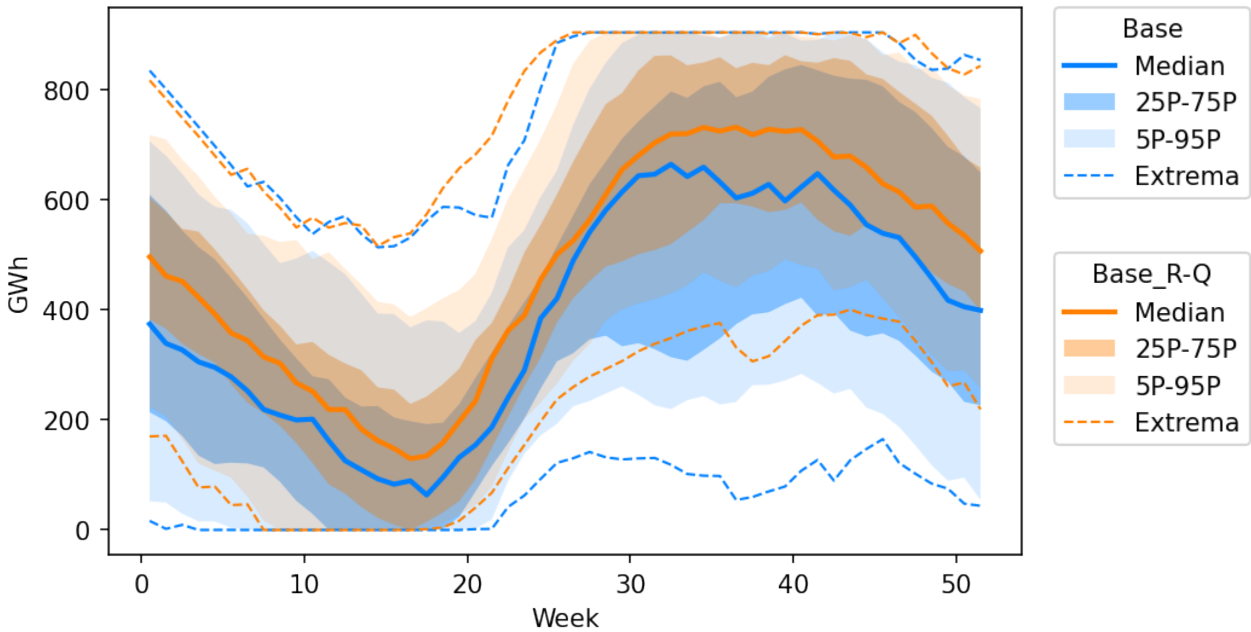

Figure 38 Simulated reservoir fillings for the module representing the lake Langevatn in Tyssovassdraget in scenario Base and Base_R-Q respectively. The module is labeled "Langv-Tysso" in the dataset. Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

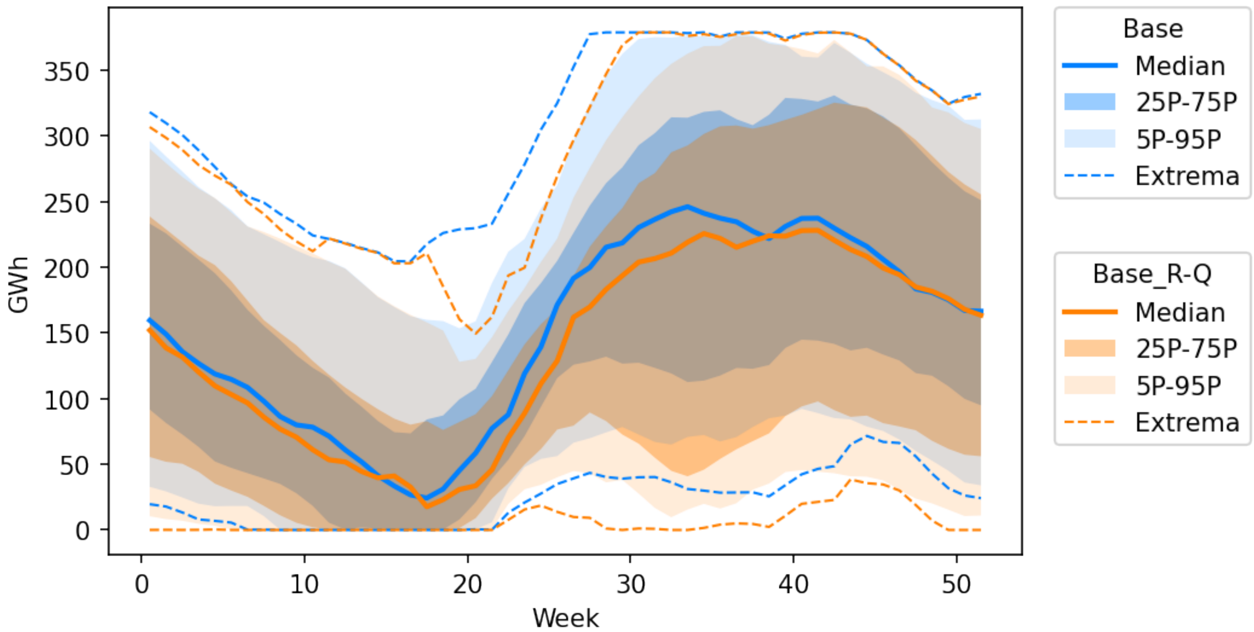

Figure 39 Simulated reservoir fillings for the module representing the dams Håvardsvatna in Tyssovassdraget in scenario Base and Base_R-Q respectively. The module is labeled "Hvardsvatn" in the dataset. Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

The case shown in Figure 38 and Figure 39 is chosen as an example that illustrates a typical type of effect of reservoir restrictions in the simulations. Note, however, that there is great variation in the detailed results among modules (or reservoirs) in the simulations.

When we turn our attention from results for individual reservoirs to regional and national levels, the results do not reveal substantial changes in reservoir operation because of new environmental restrictions. In the FanSi simulations, the reservoir constraints in isolation tend to increase the aggregate reservoir filling while minimum bypass requirements in isolation tend to lower the aggregate reservoir filling (as can be seen from Figure 72 and Figure 73 in Appendix A), and the combined effect is not substantial.

There is, however, a moderate increase in reservoir fillings in dry years also at regional and national levels. This is because reservoir constraints will have a higher impact in dry years. This finding holds true for both FanSi and EMPS model runs, as is evident from Figure 40 and Figure 41 for Norway in aggregate (to identify the increase for dry years, observe the increase in low percentile fillings in the figures). It also holds for all modelled areas and all scenarios, with the exception of scenario Base_Q (figures showing specific results for individual price areas and two additional scenarios are provided in Appendix A).

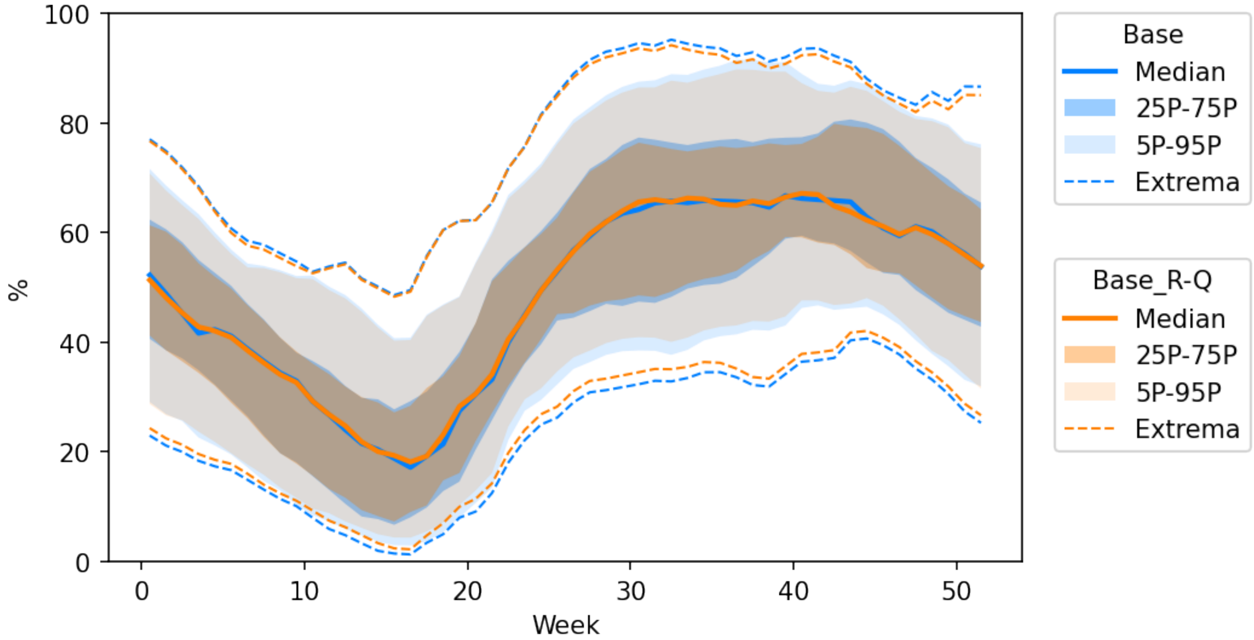

Figure 40 Simulated aggregated reservoir fillings for Norway in scenario Base and Base_R-Q, respectively. Results are measured as percentage (%) of maximum reservoir capacity. Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

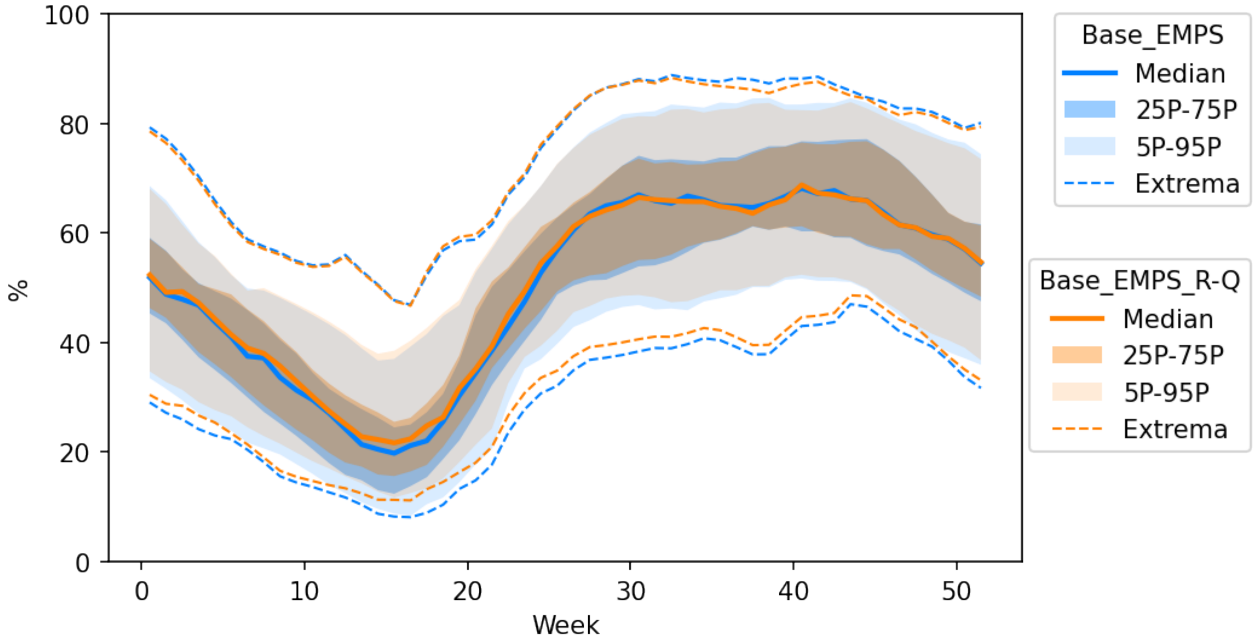

Figure 41 Simulated aggregated reservoir fillings for Norway in scenario Base_EMPS and Base_EMPS_R-Q, respectively. Results are measured as percentage (%) of maximum reservoir capacity. Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

Results of our inquiries into potential relationships between minimum bypass flow requirements and reservoir management are mixed and do not provide sufficient grounds for conclusions. However, we observe that in wet years, aggregate reservoir levels tend to decrease slightly with new environmental restrictions. This can be seen from the decrease in high percentile fillings in Figure 40 and Figure 41, and is more prominent in the FanSi results. As reservoir constraints will have limited impact in wet years when reservoir fillings are already high, we believe this effect is caused by minimum bypass requirements. Figure 73 in Appendix A (scenario Base_Q) supports this claim.

6.4 Power transmission

6.4.1 Changes in total average transmission

Average annual power transmission to Norway from abroad increases with about the same amount as hydropower is reduced in the simulations (see Section 6.1.1 for results on reduced production from hydropower). This has to do with the full utilization of hydropower under the given conditions and the limited price elasticity, which implies that reduced hydropower production need to be primarily compensated for by increased production in other countries and transmission to Norway. In the results, the ratio between the average increase in net power transmitted to Norway and the average reduction in hydropower production is between 0.9 and 1 in all scenarios.

Increased power transfers to Norway occur with all the countries Norway has important international connections with. Approximately half of the increase in net imports occurs through the power lines with Sweden. The other half is distributed among the United Kingdom, Germany, Denmark and the Netherlands, in that order of importance.

6.4.2 Changes in weekly average transmission

In addition to compensating for reduced hydropower production on an annual energy basis in the simulations, power exchange plays a central role in balancing production and consumption around weeks 18-22 in connection to the activation of reservoir restrictions in week 18. This is illustrated for Norway in aggregate by Figure 42 and Figure 43.

Figure 42 shows percentiles of total weekly power exchange for Norway over the year in scenario Base and Base_R-Q, respectively. As is evident from both the medians, 5-95 percentiles and 25-75 percentiles plotted in the figure, the simulation results show a rather steady shift towards more power transmission to Norway from other countries following the addition of new environmental restrictions. At the same time, with the new restrictions (scenario Base_R-Q) there is a particularly marked change towards more power transmission to Norway from other countries from week 18 and a few weeks onwards. This is even clearer from Figure 44, which plots directly the difference between simulated weekly power exchange for Norway in model runs with and without restrictions.

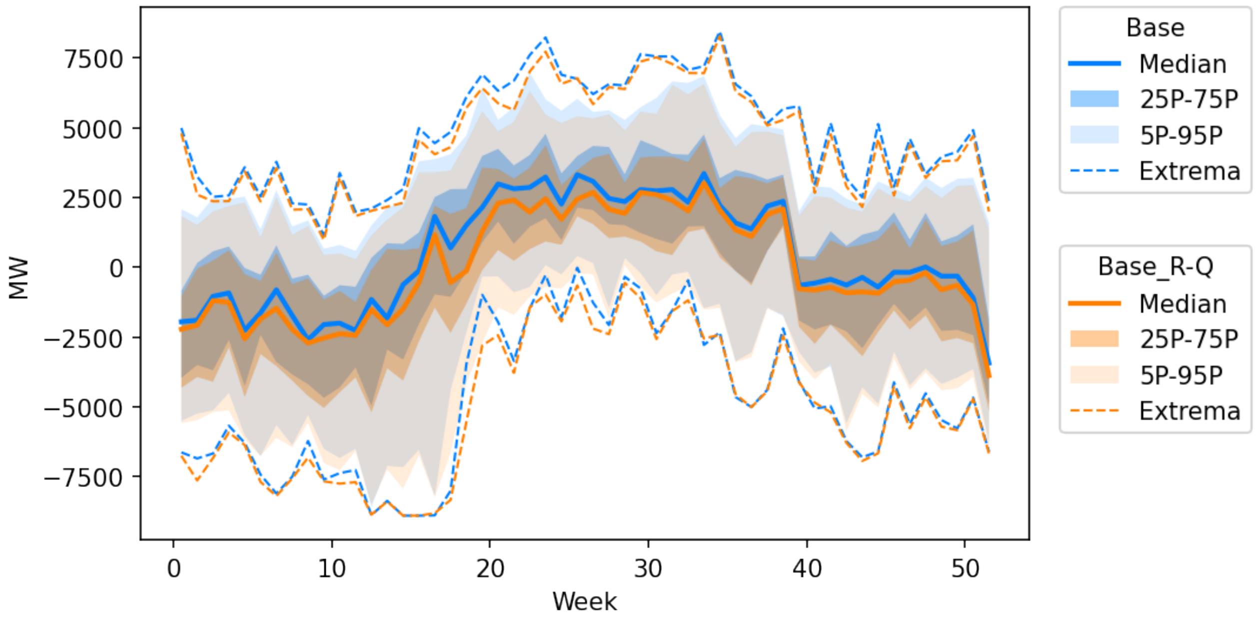

Figure 42 Simulated aggregated weekly power exchange for Norway in scenario Base and Base_R-Q, respectively. Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

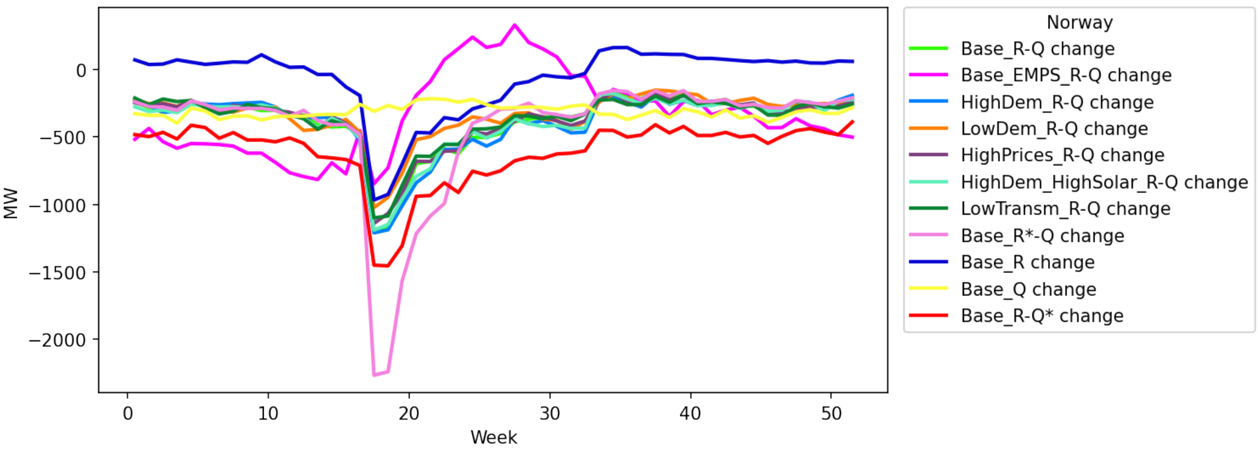

Figure 43 Change in weekly average power exchange between Norway and other countries over the year. Change is calculated as the difference between results from model runs with and without restrictions. Value > 0 means a change towards more transmission from Norway because of new environmental restrictions; value < 0 means a change towards more transmission to Norway.

The trend of increased power transmission to Norway in roughly weeks 18-22 in model runs with new environmental restrictions (Figure 43), illustrate how international connections help the system to accommodate the reduced production of hydropower in weeks 18-22 because of new restrictions. A similar type of impact can be observed in Figure 44 showing total power transmission between central Norway (model area "Norgemidt") and northern Norway (model area "Helgeland"): Note the marked but relatively short-lasting trend of increased power transmission in southward direction in weeks 18-21.

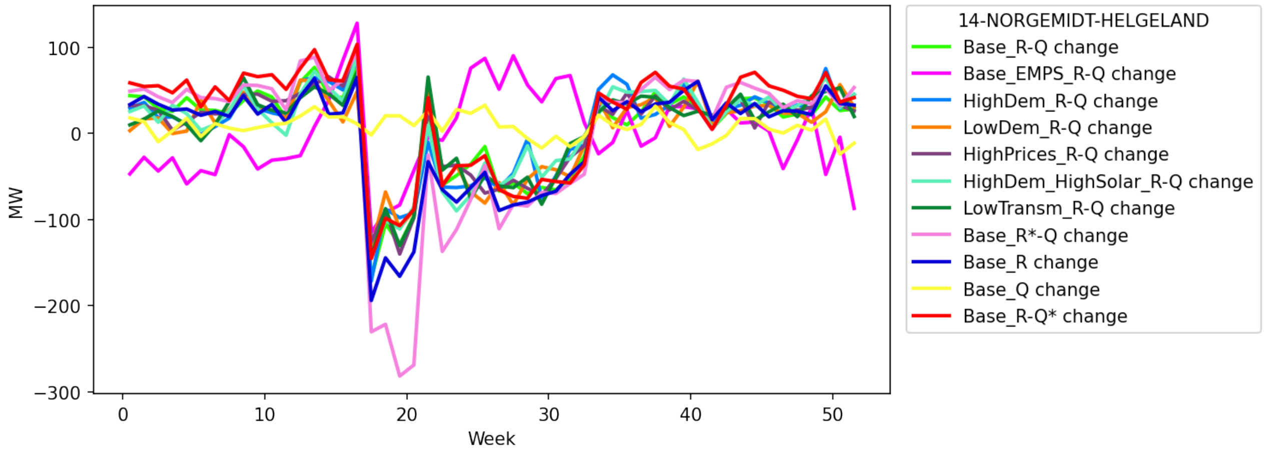

Figure 44 Change in weekly average power exchange between model areas "Norgemidt" and "Helgeland" over the year. Change is calculated as the difference between results from model runs with and without restrictions. Value > 0 means a change towards more transmission in a northward direction because of new environmental restrictions; value < 0 means more transmission southward.

6.5 Reserve capacity

The access to reserve capacity is important to maintain the balance between supply and demand in real-time and is a crucial resource for the system operators to ensure security of supply. In Norway, and the Nordic power system, regulated hydropower plants are the most important provider of reserve capacity due to its fast response time and high degree of flexibility. In this project, we have used the short-term market model Primod to analyze the effects of new environmental restrictions on the access to spinning/rotating reserve capacity in Norway.

The analysis is based on the 2030 Base and Base_R-Q scenarios and are named Base_Primod and Base_Primod_R-Q, respectively. In total 196 weeks were studied and compared (as described in Section 4.2). For each week, initial reservoir fillings and water values (cuts) for each individual reservoir are provided from the FanSi-results to the Primod model. Note that the Primod analyses builds on the results from the FanSi simulations, and therefore may have unrealistically low reservoir fillings in spring. This may lead to an underestimation of how many power plants are able to contribute with reserve capacity in this period, and correspondingly overestimate the lack of available reserve capacity in these weeks.

6.5.1 Number of hydropower plants qualified for delivering spinning reserve capacity.

Hydropower reservoirs in Norway are typically drawn down during winter due to high consumption and limited inflow. This leads to a decreasing number of power plants contributing with reserve capacity during spring (due to low reservoir fillings), until the inflow increases with the spring flood and the number of contributing plants rapidly increases. This can be seen from Figure 45. The unrealistically low reservoir levels obtained by FanSi prior to the snow melting period in dry years, also leads to an excessively low number of power plants qualifying for delivering reserve capacity (for example for week 18, 1988 and week 19, 1985).

Introducing new environmental constraints leads to 10-40 fewer power plants qualifying for reserve capacity provision between week 18 and 34 when the minimum reservoir constraints are active, as shown by the higher blue bars in Figure 45. Prior to week 18, a few more power plants (0-20) can contribute due to higher reservoir levels with new environmental constraints. This effect is largest in weeks with low overall reservoir levels (for example week 4, 2011, week 14, 1986, and week 17, 1985) as the minimum reservoir requirement has more effect on the reservoir levels in dry years, and the reservoir levels are generally higher in reservoirs with requirements that are also candidates for deliver reserve capacity.

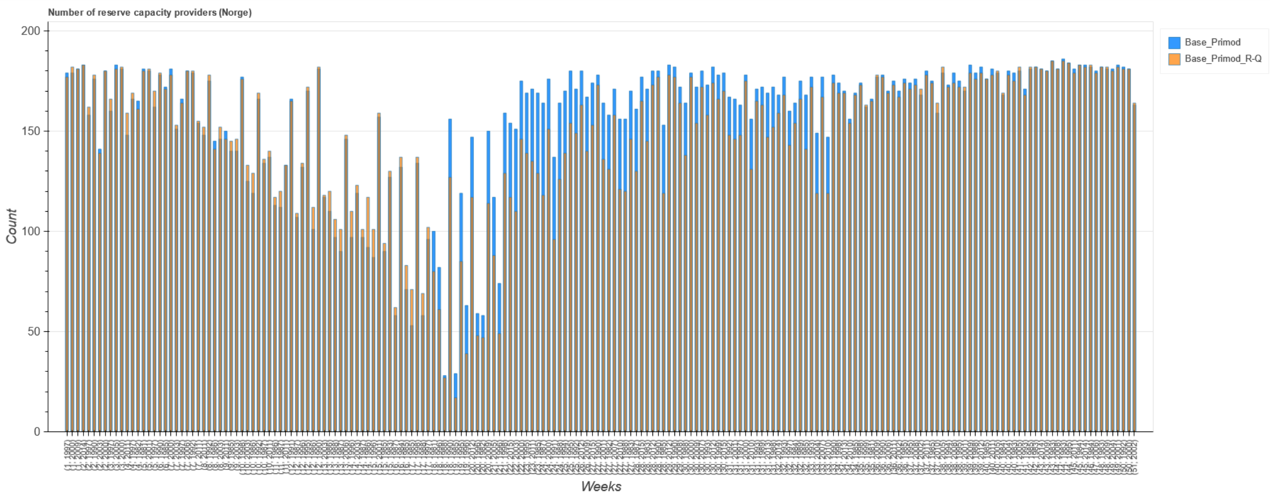

Figure 45 The number of hydropower plants able to deliver reserve capacity in Norway for all analyzed week, with and without new environmental constraints. The weeks are sorted by increasing week number.

Figure 46 show the difference in number of plants qualified for delivering reserve capacity sorted by what type of environmental constraint the plant is subject to. We can see that the large reduction in number of plants contributing between week 18-34 is due to the minimum reservoir constraints (mag). The increasing number prior to week 18 comes from power plant subject to both bypass (qforb) and reservoir constraints. We also see a small general reduction in the contributing number of plants not subject to new environmental constraints due to a general reduction in reservoir levels for these types of plants when environmental constraints are introduced.

All price areas in Norway show the same trend as for Norway as a whole, except NO1 where only eight hydropower plants can deliver reserve capacity and few of these are subject to new environmental constraints.

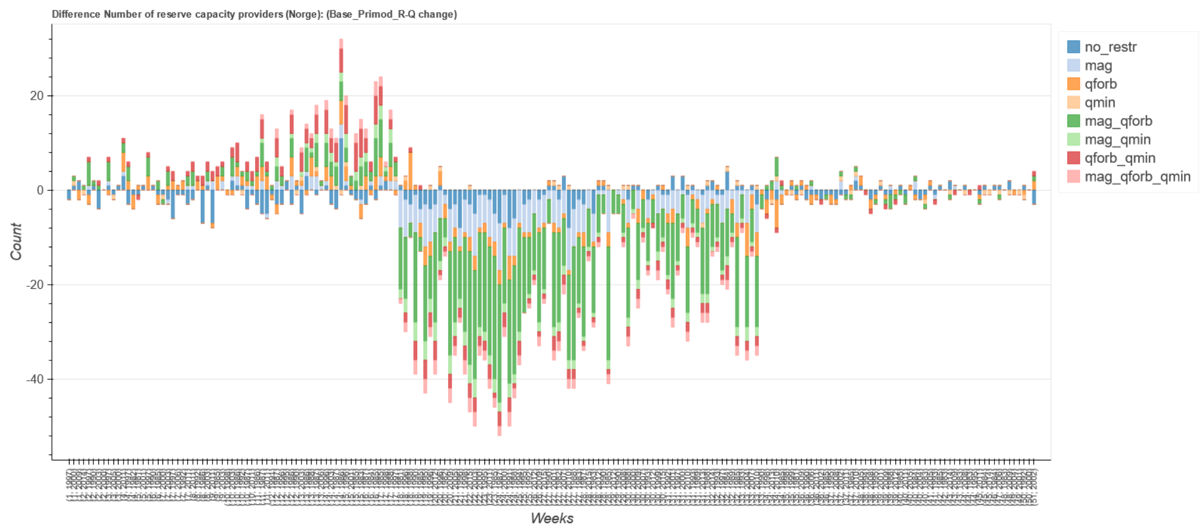

Figure 46 The difference in number of hydropower plants able to deliver reserve capacity in Norway (Base_Primod_R-Q change) for all analyzed week. The difference is shown for each category of constraint type where "mag" refers to minimum reservoir constraint, "qforb" refers to bypass constraints and "qmin" refers to minimum production constraints. "no_restr" are hydropower modules that are not directly subject to new constraints.

6.5.2 Availability of upward spinning reserve capacity

The availability of upward spinning reserve capacity in Norway is sufficient for the majority of the analyzed weeks, with weekly average upward reserve capacity prices of 0-10 €/MW. Figure 47 show the average available upward spinning reserve capacity in Norway for each studied week, both with and without new environmental constraints. The black horizontal line shows the total demand (approx. 800 MW). Approaching the snow melting period, the availability decreases, and the results show a deficit of upward reserve capacity for some of the weeks, and correspondingly higher prices. This is highly caused by the low number of hydropower plants qualified for contribution in these weeks, because of very low reservoir levels. However, the requirement of approx. 800 MW is achieved through reservation in neighbouring countries and "imports", as we will see in Section 6.5.4.

New environmental constraints seem to improve the situation prior to weeks 18, with up to about 400 MW or 0-70 % higher availability (mostly < 10 %), which is connected to the fact that more power plants can then contribute. After week 18, the availability is up to approximately 300 MW lower (0-40%) with environmental constraints for about six weeks, before the effect becomes low and more variable.

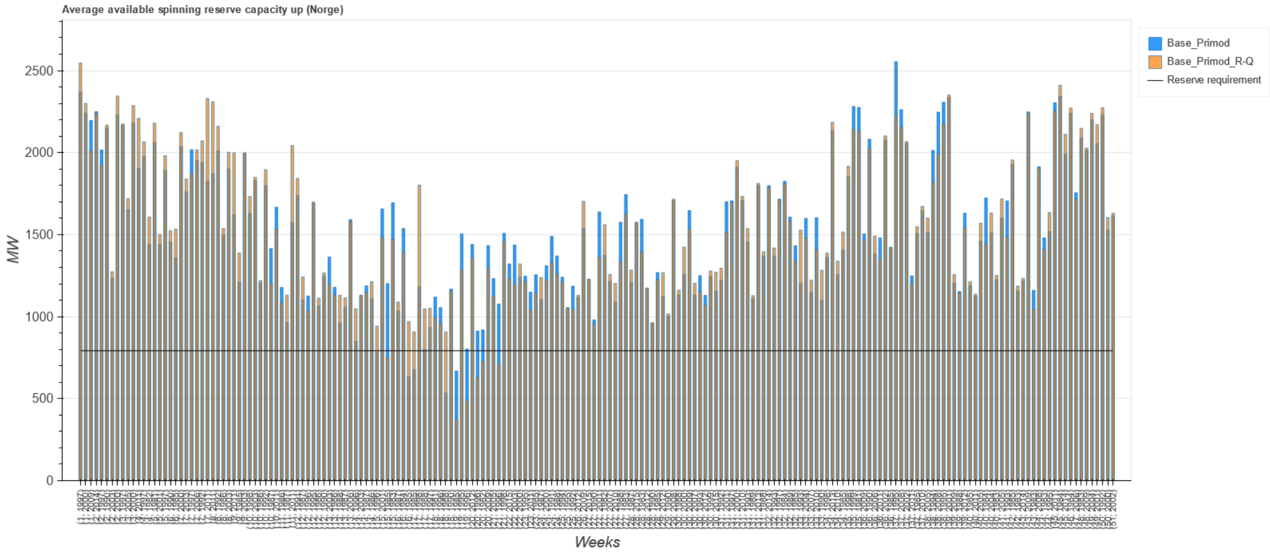

Figure 47 The availability of upward spinning reserve capacity in Norway for all analyzed week, with and without new environmental constraints.

Figure 48 show the change in upward reserve capacity for different types of power plants, depending on what types of environmental constraints they are subject to. Power plants subject to minimum production constraints (qmin) will deliver more upward reserve capacity when subject to this constraint due to the need to always produce at a minimum level. For power plants that are also subject to minimum reservoir constraints (mag), we see a reduction in available upward capacity from week 18 and a few weeks ahead due to the lack of available water in some reservoirs. Power plants subject to bypass restrictions (qforb) will deliver more capacity for the first half of the year, and less for the second half, but here there are several exceptions. Around week 18, there is generally a significant reduction for the group of power plants subject to both bypass end reservoir constraints (mag_qforb). With new environmental constraints, the group of plants without new restrictions (no_restr) will generally deliver less upward reserve capacity, except for the weeks 18-20. This is connected to the reduction in the number of power plants able to contribute due to lower reservoir fillings.

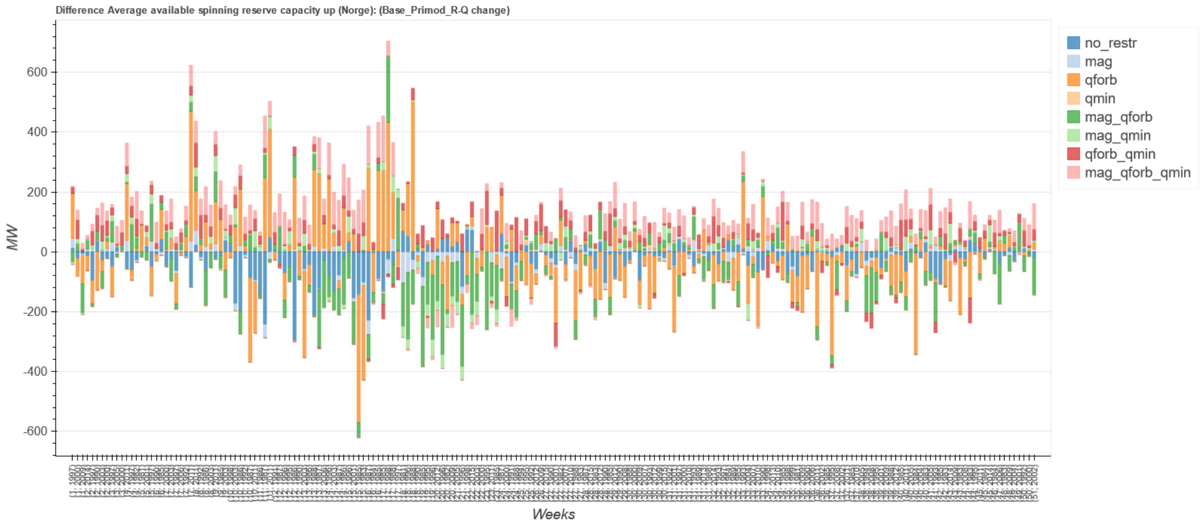

Figure 48 The difference in weekly average available upward spinning reserve capacity in Norway (Base_Primod_R-Q change) for all analyzed week. The difference is shown for each category of constraint type.

If we look at the available upward reserve capacity in each price area in Norway, it is evident that both NO1 and NO4 has a low availability compared to the demand. Consequently, these areas are depending on importing this capacity from neighbouring areas by reserving transmission capacity. In these areas, new environmental constraints often lead to a reduction in available capacity, but not in all weeks. In NO2 and NO3, the new constraints give much of the same effects as for Norway as a whole (increased availability prior to weeks 18, and lower during summer), but with more exceptions. NO5 generally experience increased upward reserve capacity due to new environmental constraints, except for the period around week 18 and in weeks with high prices during spring.

6.5.3 Availability of downward spinning reserve capacity

The results (Figure 49) show good access to downward spinning reserve capacity in Norway, and consequently the price for reserving this capacity is low (often 0 €/MW). However, we find lower levels of downward spinning reserves when production levels are low during summer, but only a deficit of capacity in a few weeks around week 18 as Figure 49 illustrates. This deficit is found in the two weeks with a very low number of power plants qualified for delivering reserve capacity, and the requirements is met through import of reserve capacity from neighbouring countries (see Section 6.5.4). It is also important to note that the available downward capacity is likely underestimated in the model, as also unregulated run-of-river, wind, and solar production can contribute with this service when they produce power.

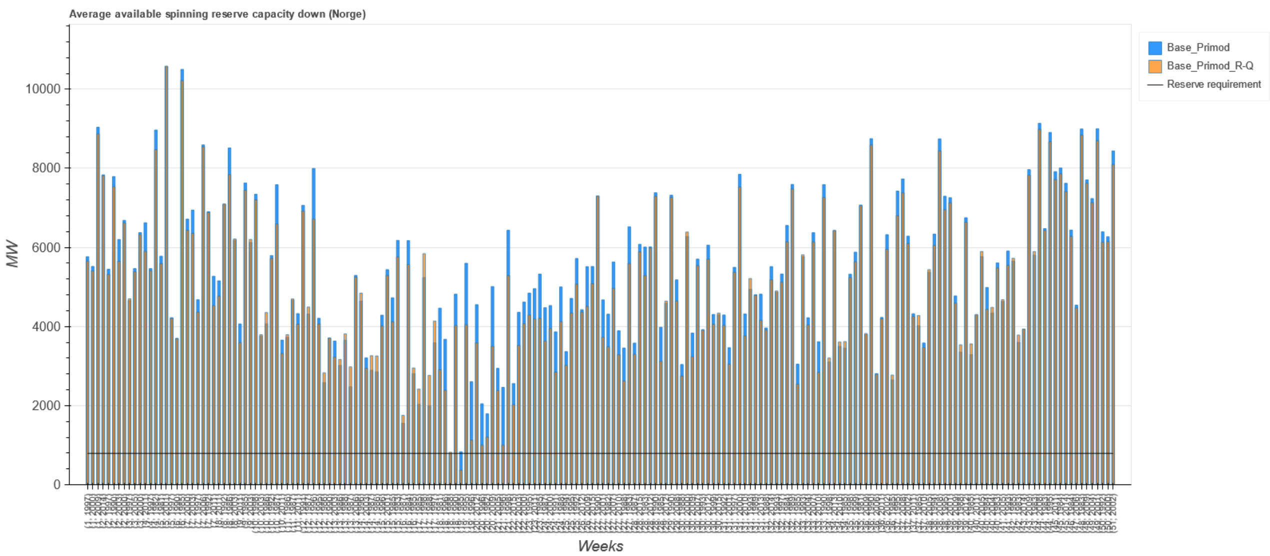

Figure 49 The availability of downward spinning reserve capacity in Norway for all analyzed week, with and without new environmental constraints.

New environmental constraints generally lead to less available spinning downward reserve capacity throughout the year, with a decrease of up to several hundred MW (0-20 %) on a weekly basis. The exceptions occur in weeks with a tight power balance and high spot prices ahead of week 18, where the constraints lead to 200-700 MW (5-30%) increase in available capacity due to higher production from the group of power plants delivering reserve capacity. Especially from week 18 onwards, there is significantly less available down-regulation capacity in Norway (up to a 1500 MW or 50% decrease) with new environmental restrictions. This is largely because fewer power plants can contribute with reserve capacity due to reservoir and bypass requirements, and thus a reduction in power production that can be regulated down.

Figure 50 show the change in downward reserve capacity for different types of power plants, depending on what types of environmental constraints they are subject to. Power plants subject to minimum bypass (qforb) generally contributes with less reserve capacity when subject to this constraint due to lower production, except for some weeks prior to week 18. New reservoir constraints (mag) reduce the available capacity from the affected plants in the constraint period (week 18-34), while the capacity increases for most weeks later in the year. Power plants subject to minimum production (qmin) will contribute with slightly less down-regulation capacity prior to week 18 due to lower production.

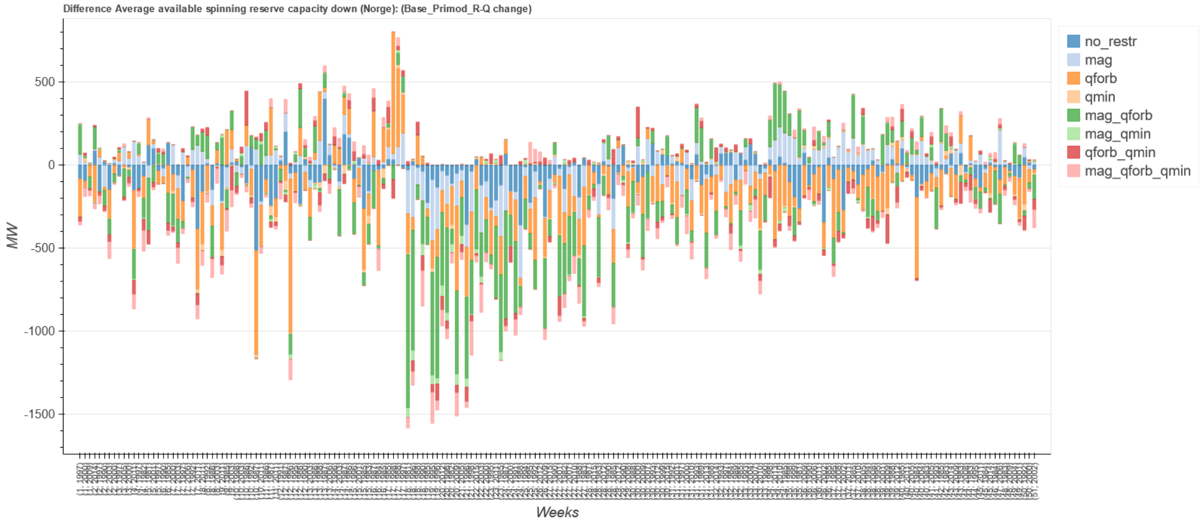

Figure 50 The difference in weekly average available downward spinning reserve capacity in Norway (Base_Primod_R-Q change) for all analyzed week. The difference is shown for each category of constraint type.

The weekly average downward reserve capacity available in NO1 is only sufficient to cover the demand in about half of the analyzed weeks, and this area is dependent on importing reserve capacity from neighbouring areas. However, as previously mentioned, this deficit in capacity is overestimated by the model as capacity provided by unregulated production is not considered. New environmental constraints lead to less available capacity at the beginning of the year, and somewhat increased levels in many weeks in the second half of the year. The strongest effect of new environmental constraints on down-regulation capacity in NO2 is found around week 18. Prior to week 18, we see an increased capacity of 30-150 %, while the period with minimum reservoir constraints experiences 10-70 % less capacity with the new constraints added. In NO3, the available capacity increases prior to week 18 and after week 32 with the new constraints but sees a general reduction of around 30 % for the weeks 18-28. In both NO4 and NO5, new constraints result in a clear reduction in available down-regulation capacity in almost all weeks. In NO4, there are some more exception in the last half of the year.

6.5.4 Exchange of spinning reserve capacity

Norway can share/exchange reserve capacity with Sweden (between NO1 and SE3, NO3 and SE2, NO4 and SE2, and NO4 and SE1) and Finland (between NO4 and FIN). The exchange of spinning reserve capacity between price areas are closely connected to the available transmission capacity and the planned flow between these areas. If the power flow from Norway to Sweden and Finland is at maximum (maximum export), there is no room for delivering upward reserve capacity to these areas without reducing the level of export. Norway can however deliver downward reserve capacity at no additional cost (without altering the spot flow). On the other hand, Sweden and Finland can share/deliver upward reserve capacity with Norway in this situation.

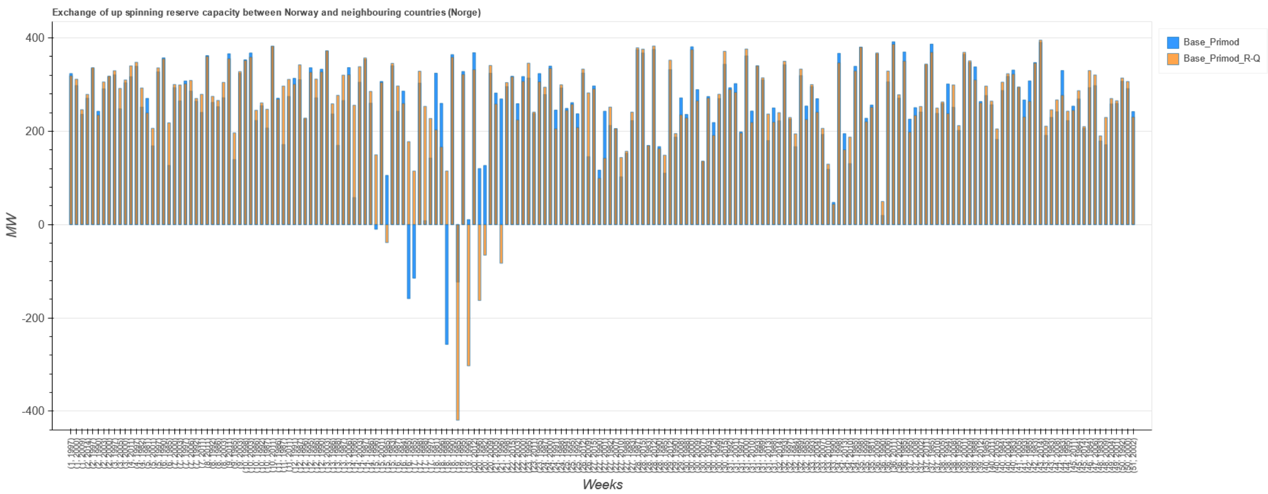

Figure 51 The net average exchange of upward spinning reserve capacity between Norway and neighbouring countries (Sweden and Finland) for all analyzed weeks for Base_Primod and Base_Primod_R-Q.

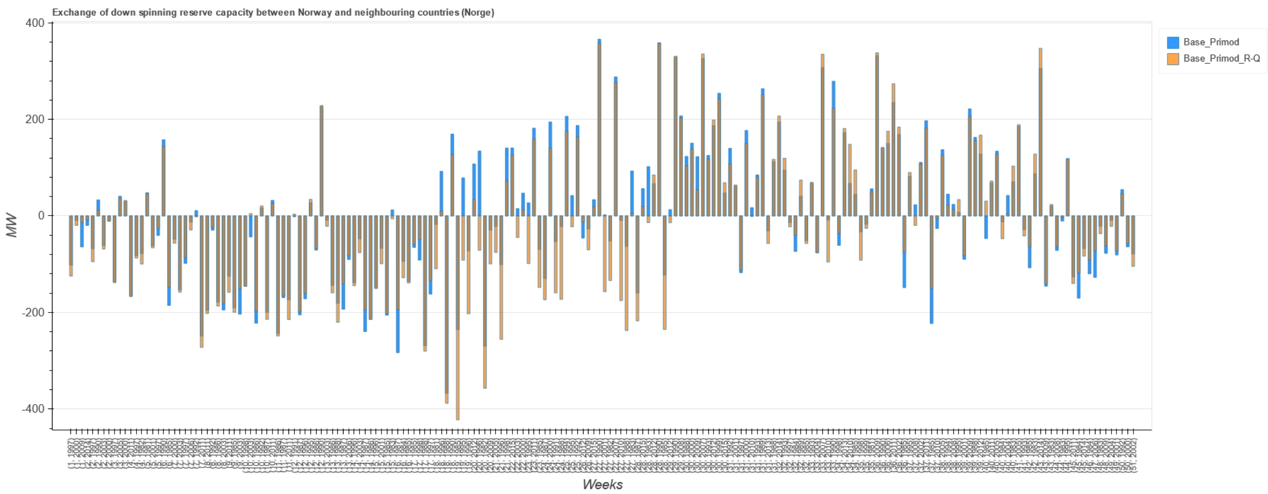

Figure 52 The net average exchange of downward spinning reserve capacity between Norway and neighbouring countries (Sweden and Finland) for all analyzed weeks for Base_Primod and Base_Primod_R-Q.

Figure 51 and Figure 52 show the net weekly average exchange of upward and downward reserve capacity between Norway and neighbouring countries (Sweden and Finland) for all analyzed weeks with and without new environmental constraints. The analyzed weeks show that Norway is a net exporter of upward reserve capacity (around 300 MW) in all weeks except around week 18. Prior to week 18, Norway exports more/imports less up-regulation capacity with new constraints, but from week 18 Norway is more dependent on importing this capacity when the new constraints are imposed. This is closely related to the effects on available up-regulation capacity in Norway.

During winter and spring, Norway imports down-regulation capacity (> - 400 MW), while we see a net export for weeks in late summer and autumn (< 400 MW). Between week 18 and 30 there is more export without environmental constraint, and more import with environmental constraints imposed. This is closely related to the fact that the production is higher without constraints (resulting in more down-regulation capacity), and that Norway also exports more (leading to "free" export of down-regulation).

6.5.5 Special periods

The results above are focused on weekly averages. Now we will look at variations within selected weeks. The selection is made based on time steps with low availability of up- or down-regulation capacity or high prices for this capacity. We have excluded the more extreme weeks around week 18, where reservoir levels are unrealistically low from the FanSi-simulations. This leads to few power plants qualified for delivering reserve capacity, and an exaggerated deficit of reserve capacity.

For upward reserve capacity, one typical situation that might lead to low availability and high prices is periods with relatively high power prices. In such periods, regulated power production is typically high or at maximum to cover the demand leading to limited possibilities to upregulate the production. We find these periods during winter and spring, but also during wet and low-price summers that experience periods with higher prices.

We find a strained power system in week 6, 1985 and week 8, 1986. These weeks have afternoons with very high demand combined with low wind power production (high residual demand) in the system. This result in very high power prices in Europe, leading to full export from Norway and very high production levels. In this period, the availability of upward reserve capacity in Norway can be below the demand of 800 MW, but around 100 MW higher in the scenario with environmental constraints. Norway, however, cover the demand by importing upward reserve capacity form neighbouring countries, and the price for upward reserve capacity is similar in both scenarios. The price for reserve capacity is found from the dual values of the reserve requirement constraint in the model. The upward reserve price will therefore reflect the additional cost of increasing the reserve requirement by one unit. In a strained situation, this might mean that you produce less at a power plant to have more upward reserve capacity available and produce more at a more expensive power plant (or shut down demand). The upward reserve capacity price will reflect the cost of this more expensive dispatch.

In week 27 and 28 in 1990, we also find periods with very low availability of upward reserve capacity in Norway. The prices for this capacity, however, is not high, as the prices only reflect the cost of re-dispatching production with relatively low costs. 1990 is a wet year with generally low power prices. In this situation, we find a low availability of upward reserve capacity in Norway in periods where prices are higher. The reason is then that the hydropower production is high (to benefit from good prices), export from Norway is at maximum and it is cheaper to import upward reserve capacity instead of covering the whole demand within Norway. We find a lower availability of upward reserve capacity in the scenario with new environmental constraints (around 100 MW less), combined with a few less power plants qualified for delivering reserve capacity.

For downward reserve capacity, a typical situation that might lead to low availability and high prices in the model is periods with low demand residual and low regulated power production. These periods are often found during summer and autumn. From the analyzed weeks, we also find the periods with low availability and possibly high prices for downward reserve capacity during this season.

Both week 27 in 2015, week 37 in 1985 and week 43 in 2014 has low power prices at the end of the week, often mid-day due to high import levels of solar power production from Europe. In these periods, hydropower production is shut down to a minimum in Norway, but we find a higher production level in the scenarios with environmental constraints, and especially for power plants subject to new environmental constraints. In week 27 and 35, the increased production generally come from power plants subject to reservoir constraints, while in week 43 the increased production comes from power plants subject to minimum production levels. As a result of this higher production level at low power prices in the scenarios with new environmental constraints, Norway generally has more available downward reserve capacity in these periods and shares more downward and upward reserve capacity with its neighbours, and consequently must import less power to be able to share downward reserve capacity. Week 27, 2015 is an exception as there are almost 25 power plants less able to deliver reserve capacity in this week due to the minimum reservoir constraint. As a result, even though the hydropower production overall is higher, the availability of downward reserve capacity is similar in both scenarios.

6.6 Socioeconomic surplus

New environmental restrictions can affect the income of hydropower producers through changes in hydropower production and changes in electricity prices. All our scenario comparisons with and without restrictions indicate reductions in hydropower production (see Section 6.1), which will contribute to reduced income. At the same time, scenario comparisons also indicate power price increases on average. This can generally be expected to contribute to increased income for hydropower producers, though this is determined not by the average market price *per se*, but by the price the producers achieve upon selling the electricity.

In the simulation results for most scenarios and model areas, reduced income due to reduced hydropower production outweighs increased income due to price effects, resulting in a negative average net effect for hydropower producers (Figure 53). For instance, in the FanSi simulations under basic assumptions and when both minimum flow requirements and reservoir restrictions are analyzed together, the income of hydropower producers decrease by an average of 0.9% for Norway (excluding one period with unrealistic results in the average calculation). Income decreases in all areas subjected to new environmental requirements, with the most significant reduction of 1.5-2.0% in the areas of "Telemark" and "Vestmidt." This is related to reductions in average power production also being relatively high in these two model areas.

In calculations based on EMPS, the income of hydropower producers decreases by 0.6% on average for Norway (which is more favorable compared to 0.9% based on FanSi). In the EMPS results, the average income increases by 0.5% and 0.9% in the model areas "Helgeland" and "Finnmark," respectively, because the price effect dominates over the reduced production effect (there is a decrease in income in the area "Troms", however, which explains why the aggregated result for NO4 in Figure 53 is negative).

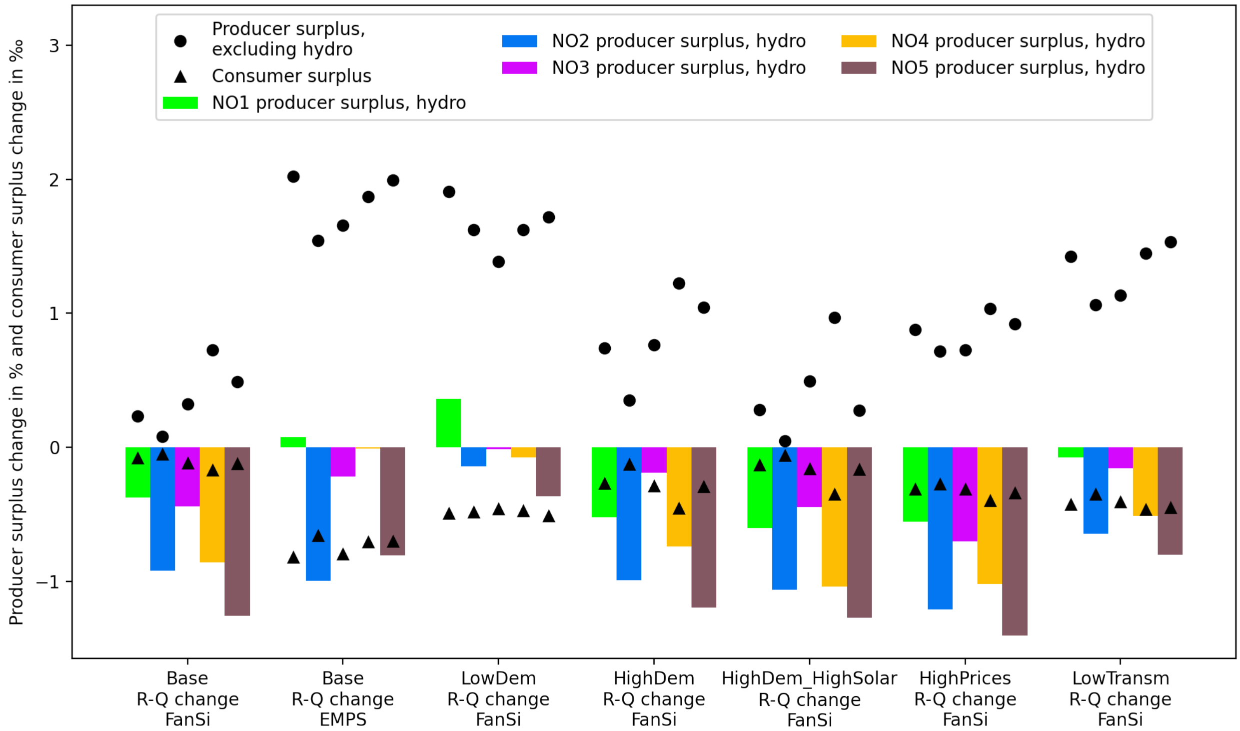

Figure 53 Estimated changes in producer surplus (relative change in %) and consumer surplus (relative change in ‰) due to new environmental restrictions. Producer surplus is equivalent to producer income.

Power producers that do not face new restrictions – whether they are producers of hydropower or wind or solar power – tend to experience increased revenues due to rising electricity prices, while consumer surplus tends to decrease for the same reason. For example, it may be noted from Figure 53 that producer surplus for non-hydro power producers (primarily wind and solar power producers) increases. The consumer surplus as shown in Figure 53, on the other hand, decreases.

6.7 Specific occurrences

In the following, we present five specific occurrences on an individual basis. The five occurrences are provided as examples to illustrate types of effects that we observe in the simulation results for individual periods. All the examples are obtained from simulation results from the FanSi model.

The first two examples are presented in Figure 54 and Figure 55, representing simulated periods in the years 1985 and 1996, respectively. These two instances share several common characteristics: Both occur in relation to relatively dry periods with relatively low inflow and low total reservoir fillings before the spring snowmelt. Further, both incidents show reductions in hydropower production and increases in power price in week 18 in model runs where new environmental restrictions are added (Base_R-Q, Base_R, Base_Q) compared to the model run without restrictions (Base). The primary explanation for these changes likely lies in the activation of reservoir restrictions in week 18. This conclusion is supported by the similarity in the magnitudes of changes observed in Base_R-Q and Base_R, as evident when comparing panels d and e in both figures, contrasted with the smaller changes observed in Base_Q, as seen in panel f.

In the 1985 case, the changes to hydropower production and marked prices are confined to week 18, whereas in the 1996 case, the effects extend into subsequent weeks (up to week 22). We do not observe notable differences in any of these effects across areas in Norway.

Another example demonstrating increase in power prices during week 18 is offered in Figure 56, which shows simulation results from the year 1981. Unlike the trends observed in 1985 and 1996, the reservoir fill levels in 1981 are not unusually low compared to other simulated weather years, as Figure 56b shows. In this sense, the situation in 1981 is less constrained than those in 1985 and 1996. On the other hand, week 18 in 1981 is also influenced by notably high temperature-dependent power demand (Figure 56c) coupled with distinctively low inputs from wind and solar power production during the latter part of week (Figure 56d). These two circumstances alongside the activation of environmental restrictions add pressure on the system during week 18. The simulation results illustrate a reduction in hydropower production and an increase in power prices throughout week 18, as depicted in Figure 56e and Figure 56f.

Figure 57, representing a simulated period in the year 1997, presents effects that diverge from those just discussed. These effects are observed in week 17 and are characterized by increases in hydropower production and decreases in power price in a model run where new environmental restrictions are introduced, as demonstrated in Figure 57d and e. We attribute these effects to higher total reservoir fillings in week 17 within the Base_R-Q simulation, as depicted by Figure 57c. The elevated reservoir fillings in the weeks leading up to week 18 are likely a response to the impending activation of restrictions in week 18. They can be interpreted as part of the power system model's strategy for coping with the additional restrictions on reservoir operation commencing in week 18.

Finally, Figure 58 illustrates a specific case where the introduction of a reservoir restriction results in increased flooding. The case pertains to simulated weeks 24-28 in year 2015 for the "Graasjoe" module located within the "Norgemidt" model area. The module represents the actual lake Gråsjøen in Trollheimen. It is assigned a new reservoir restriction in our analysis. As Figure 58a and b show, the period under consideration is not particularly wet in terms of inflow, nor in terms of reservoir filling when simulating without new restrictions (Base). In the simulations incorporating new restrictions (Base_R-Q), however, the spring increase in reservoir fillings is significantly accelerated, leading the reservoir to reach its maximum water storage capacity by week 25 (Figure 58d). Consequently, unlike in the Base scenario,

scenario Base_R-Q yields flooding in weeks 25-27 (Figure 58f). While Base_R-Q maximizes production throughout this entire period (Figure 58e), this is insufficient to prevent flooding from occurring.

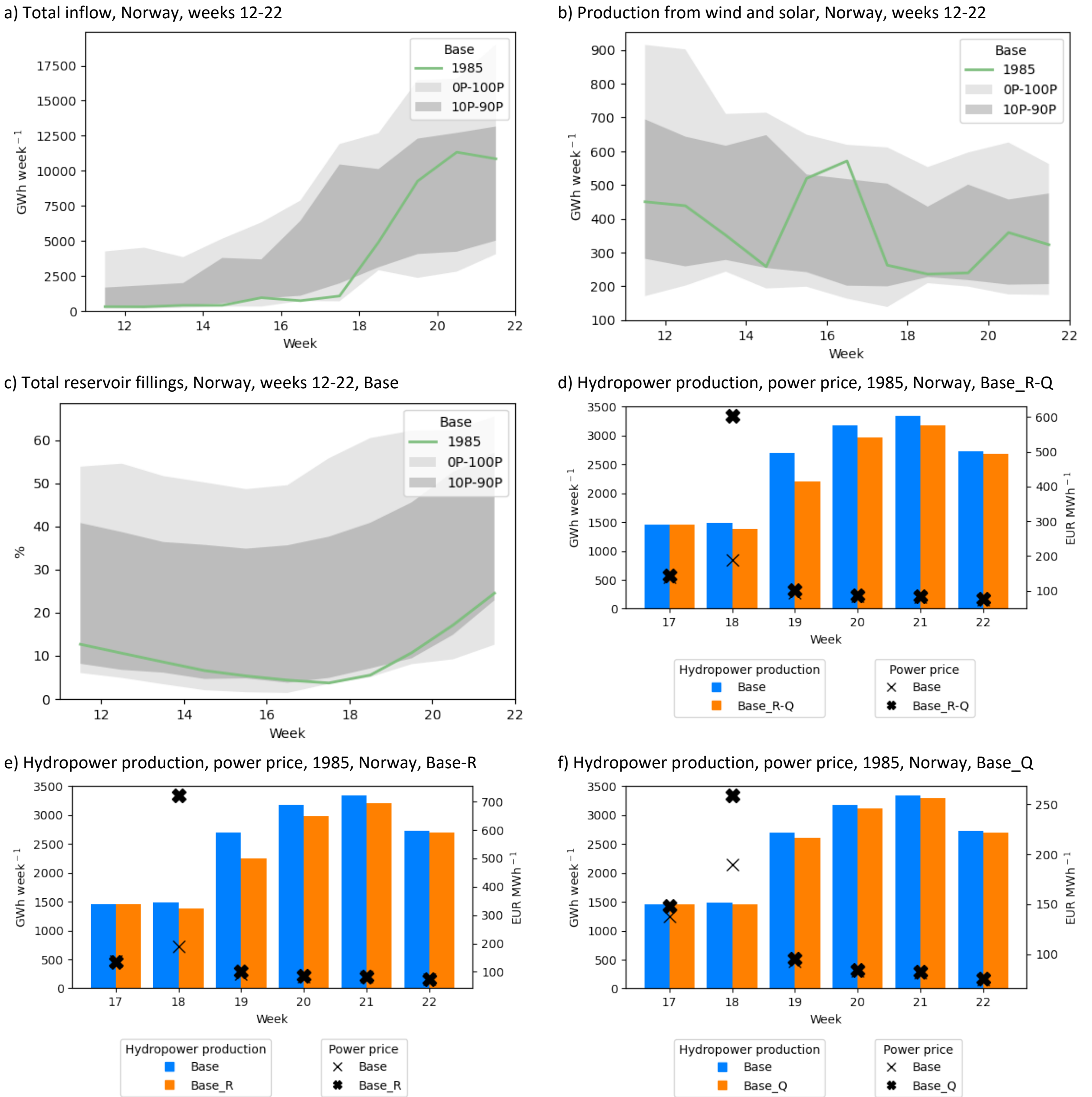

Figure 54 Plots illustrating a specific occurrence of reduced hydropower production and increased power prices in scenarios with new environmental restrictions (Base_R-Q, Base_R and Base_Q) compared to the scenario without new restrictions (Base). Panels a-c provide background information to assess the specific occurrence, showing total inflow (a), power production from wind and solar (b) and hydropower reservoir fillings (c) for Norway in weeks 12-22. Panels d-f compare hydropower production and power price for Norway without and with new environmental restrictions in simulated year 1985 specifically. In panels a-c: "0P-100P" denotes 0-100 percentiles range and "10P-90P" 10-90 percentiles range across 35 simulated weather years. In panels d-f: Results shown represent weekly mean values for hydropower production and power price.

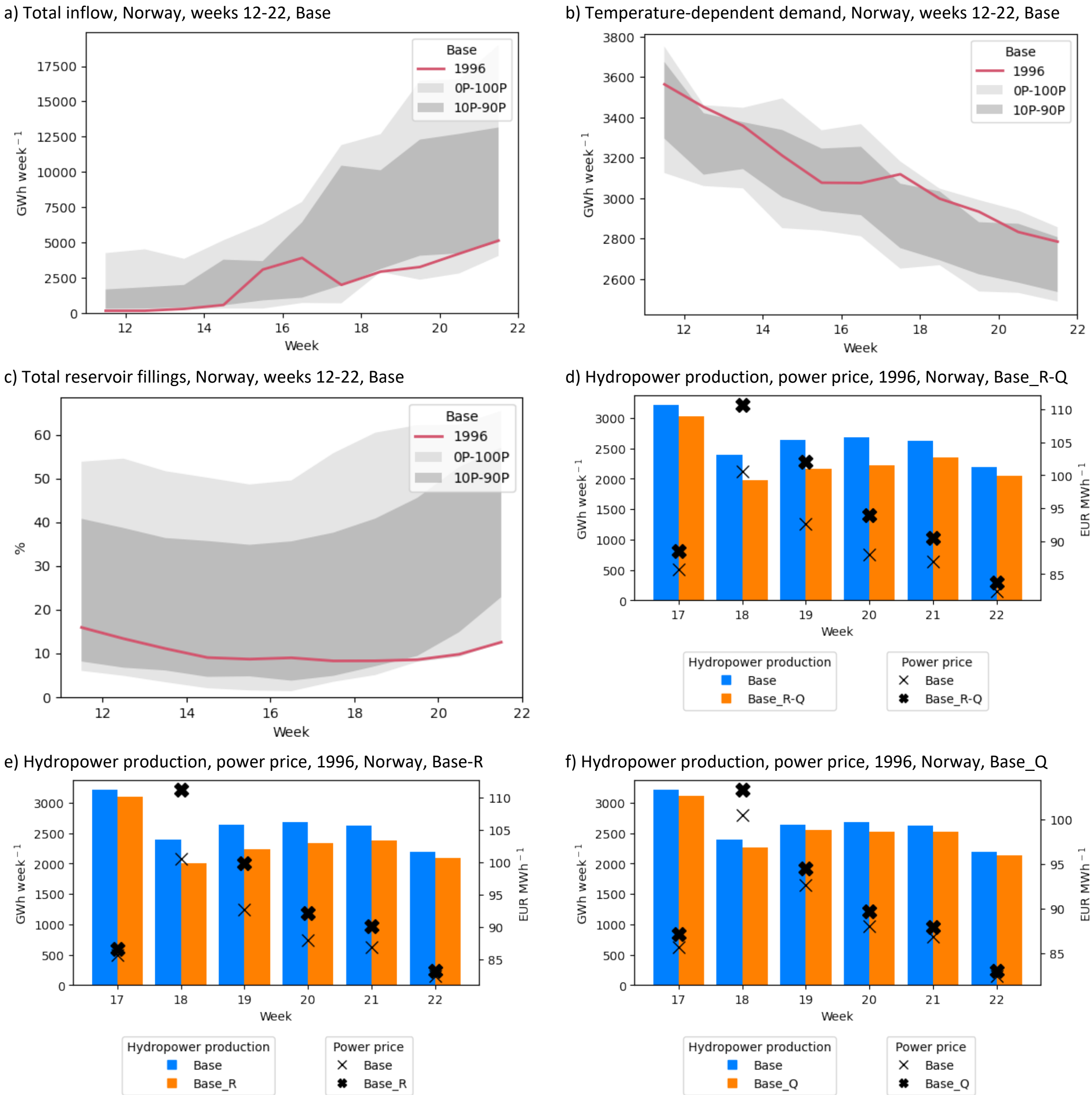

Figure 55 Plots illustrating a specific occurrence of reduced hydropower production and increased power prices in scenarios with new environmental restrictions (Base_R-Q, Base_R and Base_Q) compared to the scenario without new restrictions (Base). Panels a-c provide background information to assess the specific occurrence, showing total inflow (a), temperature-dependent demand (b) and hydropower reservoir fillings (c) for Norway in weeks 12-22. Panels d-f compare hydropower production and power price for Norway without and with new environmental restrictions in simulated year 1996 specifically. In panels a-c: "0P-100P" denotes 0-100 percentiles range and "10P-90P" 10-90 percentiles range across 35 simulated weather years. In panels d-f: Results shown represent weekly mean values for hydropower production and power price.

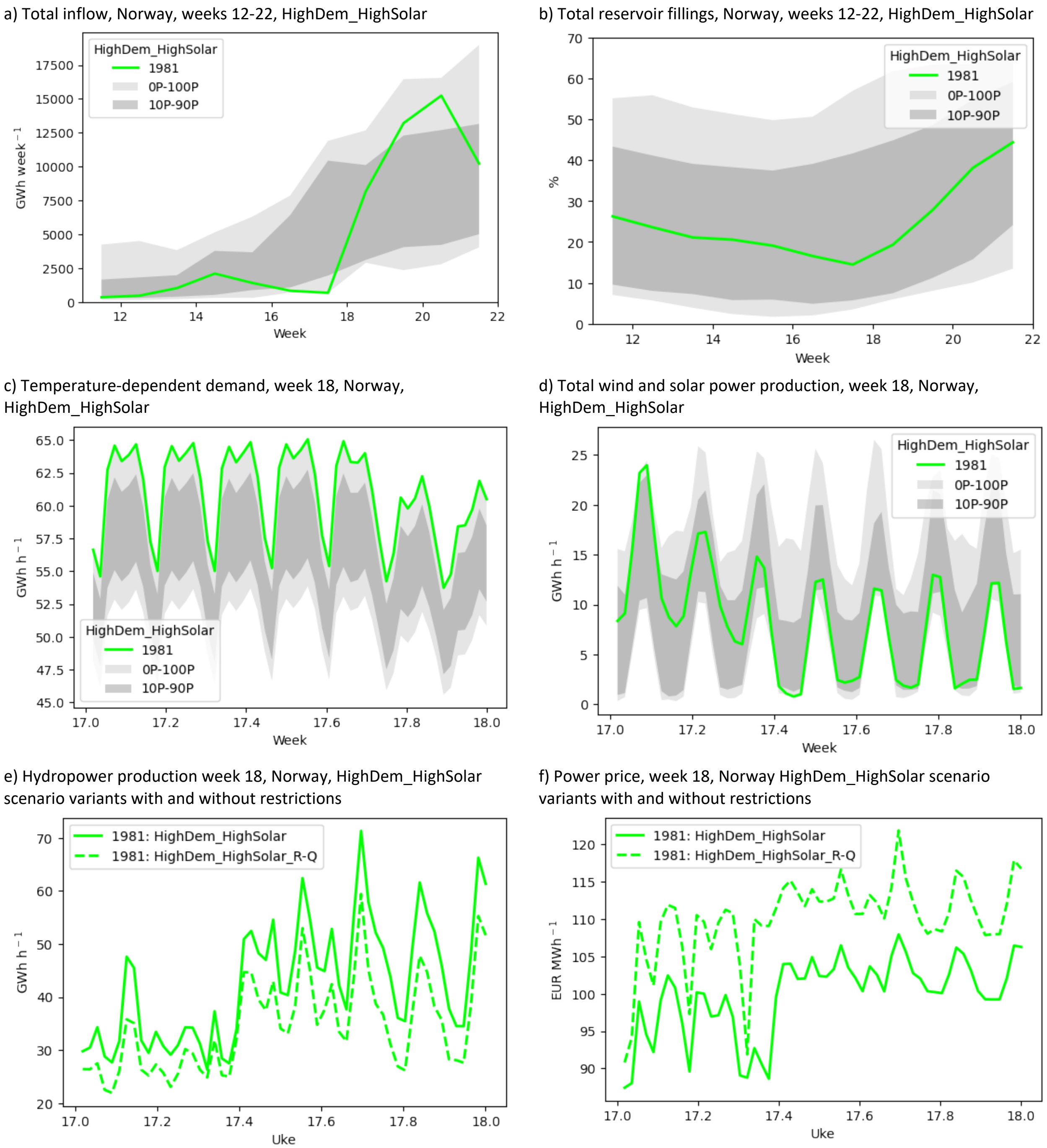

Figure 56 Plots illustrating a specific occurrence of decreased hydropower production and increased power prices (week 18) in a scenario with new environmental restrictions (HighDem_HighSolar_R-Q) compared to the scenario without new restrictions (HighDem_HighSolar). Panels a-d provide background information, showing a) total inflow, b) reservoir fillings for HighDem_HighSolar, c) temperature-dependent demand for HighDem_HighSolar, and d) total wind and solar production for Norway. Panels e-f show, respectively, comparisons of hydropower production and power price for Norway without and with new environmental restrictions in simulated year 1981. Panels a-c: "0P-100P" denotes 0-100 percentiles range and "10P-90P" 10-90 percentiles range across 35 simulated weather years. Panels a-b: values with weekly time resolution are plotted. Panels c-f are plotted at three-hourly time resolution for week 18.

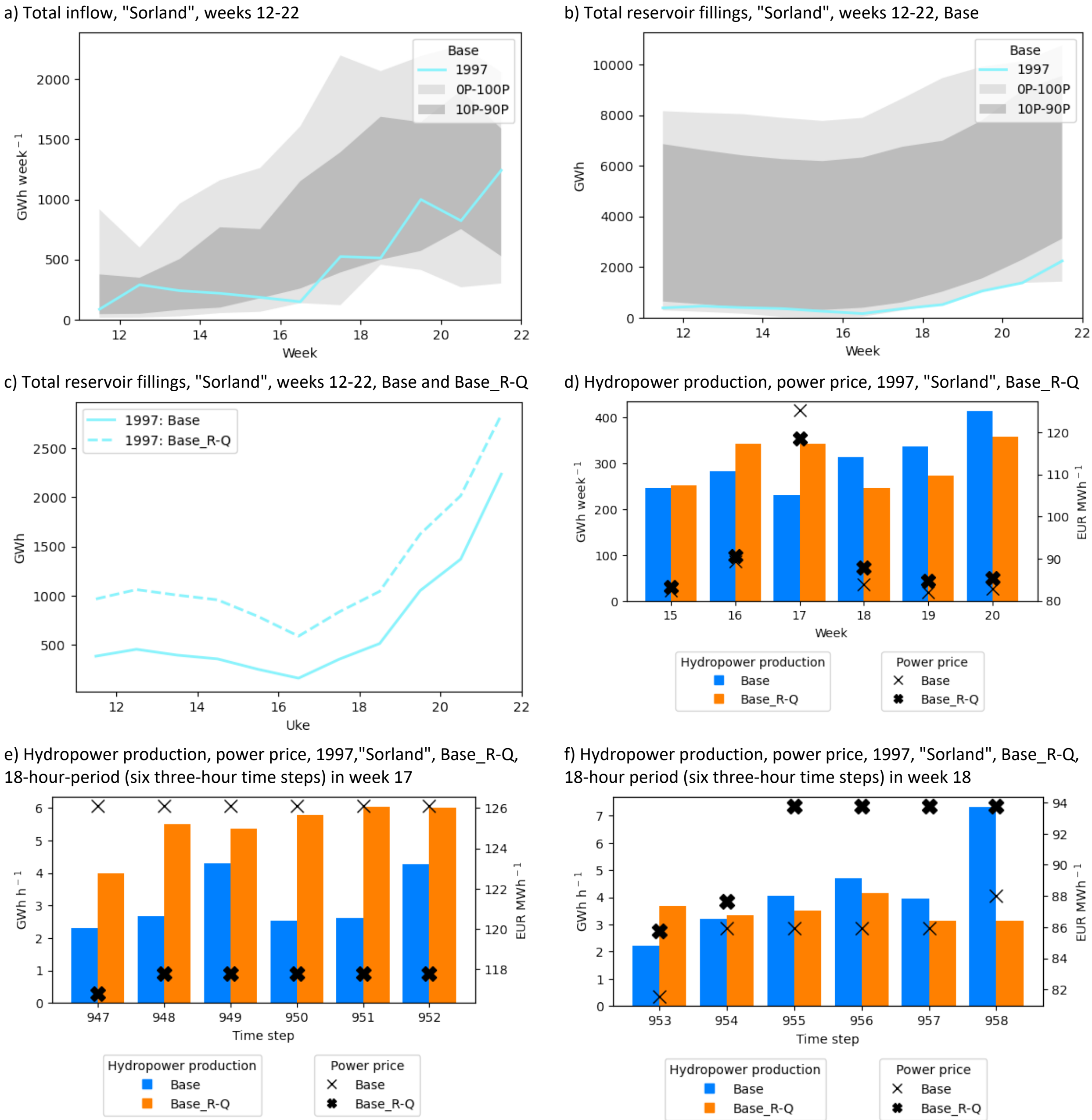

Figure 57 Plots illustrating specific occurrences of both increased hydropower production and decreased power prices (week 17) and reduced hydropower production and increased power prices (week 18) in a scenario with new environmental restrictions (Base_R-Q) compared to the scenario without new restrictions (Base). Panels a-c provide background information to assess the specific occurrences, showing total inflow (a), reservoir fillings for Base (b) and a comparison of reservoir fillings for Base and Base_R-Q (c) for model area "Sorland" in weeks 12-22. Panels d-f compare hydropower production and power price for Norway without and with new environmental restrictions in simulated year 1997 specifically. In panels a-c: "0P-100P" denotes 0-100 percentiles range and "10P-90P" 10-90 percentiles range across 35 simulated weather years. In panels d-f: Results shown represent weekly mean values for hydropower production and power price.

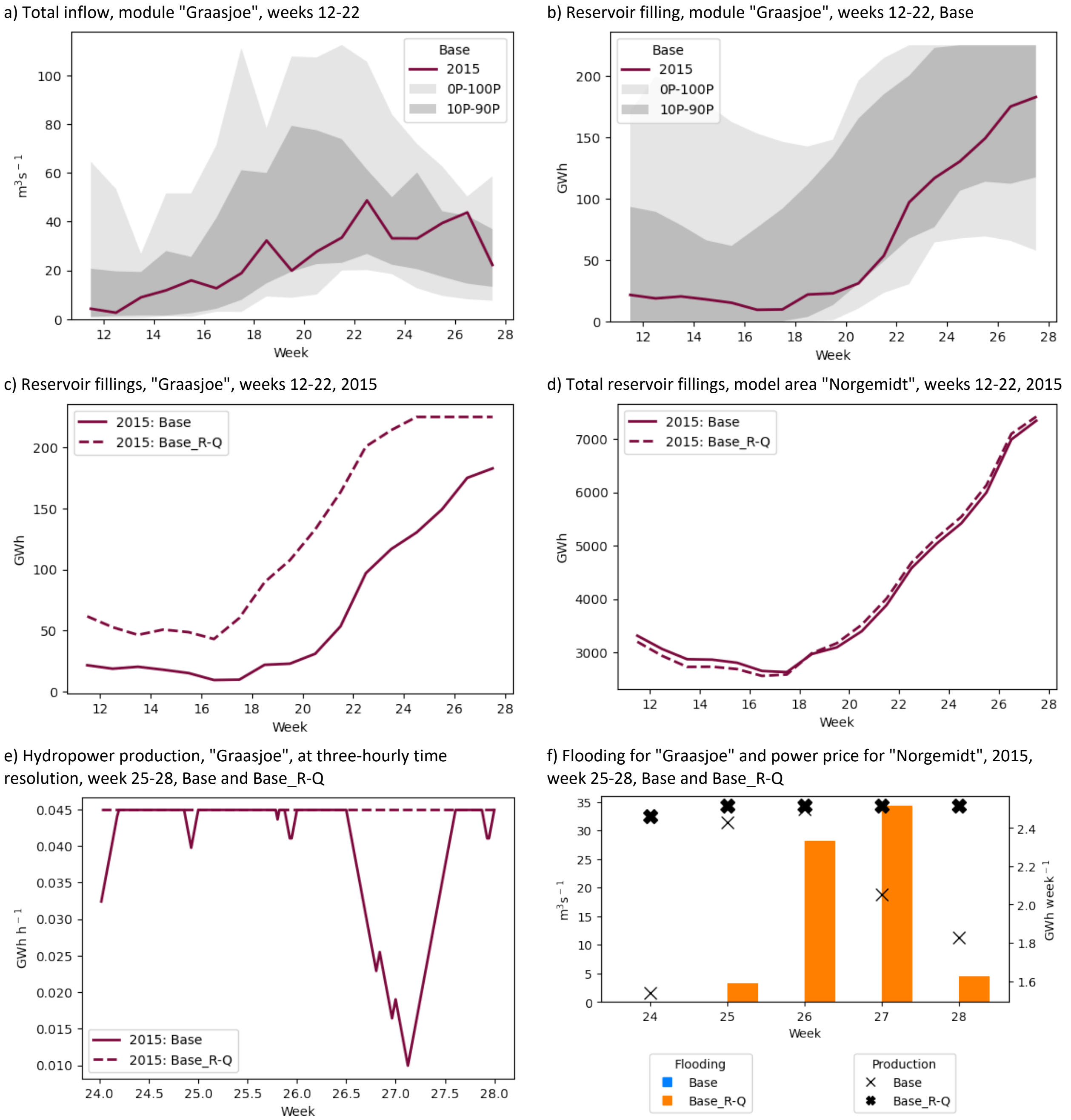

Figure 58 Plots illustrating a specific occurrence of increased flooding in a scenario with new environmental restrictions (Base_R-Q) compared to the scenario without new restrictions (Base). Panels: a) total inflow for module "Graasjoe"; b) reservoir fillings for "Graasjoe"; c) comparison of reservoir fillings for "Graasjoe" for Base and Base_R-Q; d) corresponding comparison of reservoir fillings for model area "Norgemidt" (to which "Graasjoe" belongs); e) comparison of hydropower produced by module "Graasjoe" for Base and Base_R-Q at three-hourly time resolution; and f) comparison of flooding (columns, measured on left vertical axis) and weekly power production (markers, measured on right vertical axis) for selected weeks in year 2015. "0P-100P" denotes 0-100 percentiles range and "10P-90P" 10-90 percentiles range across 35 simulated weather years. There are no blue columns in panel f because values are zero.

7 Discussion and conclusions

Hydropower plants in Norway typically operate under licenses that specify terms for their operation. Following the implementation of the EU Water Framework Directive through The Norwegian Water Regulation, many licensing conditions have recently undergone revisions or are about to undergo revisions that introduce stronger environmental protection requirements for regulated watercourses. As a result of these revisions, there may be changes or new conditions for minimum river flows or constraints imposed on reservoir operation. This may lead to both reduced hydropower production in total and reduced flexibility in production. For hydropower producers, the transmission system operator and other actors in the power sector, it is important to understand how the changed and new conditions for hydropower may impact the power system as a whole.

In the project, "New environmental constraints – consequences for the power system" (short name "SumEffekt"), we have employed state-of-the-art power system optimization models to analyze power systems for the year 2030 with and without assumptions about new environmental restrictions for hydropower. Potential future consequences of revisions to the operating conditions for hydropower have been identified from the report NVE 49/2013 (Sørensen et al. 2013) and implemented in the power system models as either minimum flow requirements or reservoir restrictions. A new method developed in the project has been used to estimate minimum bypass flow requirements. Finally, impacts of environmental restrictions have been quantified by comparing results from model runs with and without restrictions. The results show changes in hydropower production, flooding, price volatility, reservoir operations, socioeconomic surplus, and availability and exchange of reserve capacity.

The power system model FanSi has been the main assessment tool, supplemented by Primod for short-term analysis of reserve capacity. In addition, the base scenario dataset has been run using the EMPS model to allow for comparisons of results from the prototype FanSi model with the well-established EMPS model.

In the following subsections, we offer discussion and conclusions that supplement the results presentation already given in Section 6.

7.1 Hydropower production

We estimate that Norway's hydropower production will decrease by about 3 TWh yr^{-1} on average, corresponding to 2% of the total hydropower production. This is primarily attributable to new minimum bypass flow requirements and to a lesser extent from reservoir restrictions. This estimate is relatively consistent across all scenarios involving our best assumptions for new environmental restrictions, regardless of factors like assumed power demand levels or whether the FanSi or EMPS model is used. It should be emphasized that the 3 TWh yr^{-1} reduction concerns flexible electricity production.

The reduction of 3 TWh yr^{-1} is our best estimate and is consistent across alternative model runs, but at the same time there is considerable level of uncertainty. Much of the uncertainty stems from the estimation of minimum bypass requirements in lieu of actual license conditions. Both the number and stringency of bypass requirements in actual licenses may differ significantly from our estimates. Note that we also have not considered the possibility that hydropower producers in practice incorporate safety margins into river flows as a cautious measure to mitigate risks or potential problems with violating minimum flow requirements.

It can also be kept in mind that our developed method for estimating minimum bypass flow requirements gives considerably lower impacts than using Q95 to represent minimum bypass as in earlier estimates by NVE (Sørensen et al. 2013). When comparing our estimates to available information on actual requirements, we find that our estimates are generally more realistic than non-adjusted Q95, which tends to overestimate requirements in general. There is some uncertainty, however, especially because our comparison has limited scope, and we observe significant variations between locations.

As for changes related to the seasonal profile of hydropower production, we note that for individual power plants that receive water from reservoirs subjected to new restrictions in the spring and summer period, one can expect a reduction in average production in the spring after the restriction becomes active. In the simulation results, this decrease in production during spring is compensated by increases in production during other times of the year – this can be winter or summer increases depending on the specific system. When considering aggregated results for entire regions, the findings are mixed. Results from FanSi suggest a relatively consistent decline in average production throughout the year, except for a particularly significant reduction in weeks 18 and 19 due to reservoir constraints that become binding in week 18. Meanwhile, results from EMPS show reduced production in winter and increased production in summer on average, with the summer increase being associated with fuller reservoirs. These differences are caused by differences in the two models reservoir operation strategies.

7.2 Power price

On the basis of the present results, we conclude that electricity prices will likely increase slightly on average as a consequence of the new environmental requirements. At the same time, we do not have reason to suggest that the average increase will be significant. The simulations yield average increases ranging from 1 to 2% depending on the scenario (when excluding a single period with unrealistic results from the calculation of average change, as explained previously in Section 6.2). The primary reason for the increase in the average electricity price is the minimum bypass flow requirements, with reservoir restrictions playing a secondary role. Overall, simulation results show relatively consistent increases in electricity prices for almost all simulated periods, with some exceptions.

The simulations identify certain incidents after reservoir restrictions are activated and bypass requirements in increase in week 18, where little water is stored in the reservoirs and the new environmental restrictions result in relatively large price increases. These occurrences indicate that environmental restrictions can potentially cause high prices or exacerbate already high prices in periods where power supply is challenging. The main explanation for this effect lies in the fact that the reservoir restrictions reduce the proportion of inflow that can be utilized for power production. An additional and reinforcing effect can come from minimum bypass flow requirements, as these requirements lead to water being diverted from power generation and this diversion also increases from week 18.

On one hand, there are only a small number of incidents where the new environmental restrictions cause high prices or significantly exacerbates already high prices. On the other hand, some incidents occur, and it is reasonable to assume that the power system models to some extent underestimate such events. Thus, overall, it remains unclear to what extent the new environmental restrictions will increase the likelihood of high prices in challenging periods.

In most of the simulations, and especially from EMPS, there is a tendency for the lowest prices to become even lower with environmental restrictions, but the picture is not uniform. In the simulations with FanSi under baseline assumptions, we observe a weak tendency for the lowest prices to become even lower because of the new environmental constraints. In the corresponding EMPS simulations, this effect is significantly more pronounced. In general, this type of effect is related to the reservoir restrictions leading to larger quantities of water in the reservoirs when the system enters periods of heavy rain in the summer or fall. The effect is not related to the new minimum flow requirements.

Simulated results for power prices appear relatively similar across regions in Norway. However, it is important to note that the power system models tend to underestimate differences in prices between regions compared to real-world conditions. This underestimation can be primarily attributed to idealizations and simplifications inherent in the models and their applications. One significant factor is the lack of modeling of physical power flow.

One noteworthy regional difference that we observe in the results is that average price increases are comparatively smaller for the model area "Sorland". We interpret this finding as an illustration of influence of international grid connections (in this case between "Sorland" and the countries Denmark, Germany and the Netherlands), where the international connections mitigate the effects of a price-increasing change. Apart from this finding, the results do not present sufficient grounds for drawing definite conclusions regarding potential differences in the impacts on average electricity prices across different geographic areas.

7.3 Reservoir operation

As can be expected given how reservoir restrictions are defined in our analysis, reservoirs with new restrictions get more rapid water level increase during the spring period. This trend is in broad alignment with the purpose of reservoir restrictions in a real-world context. Simultaneously, reservoir fillings tend to decrease for reservoirs without new restrictions.

On the aggregate level, results show only minor changes in reservoir operation, implying that the new environmental requirements do not have a major impact on overall reservoir storage in the simulations. In essence, these findings suggest that redistributing water across reservoirs provides flexibility that helps to adapt to challenges posed by new environmental restrictions. We can also say that new reservoir restrictions lead to more utilization of the flexibility in reservoirs without restrictions. In addition, reservoir constraints and minimum bypass requirements seem to have opposite effects on aggregate reservoir level as minimum bypass requirements tend to decrease reservoir levels, and reservoir requirements tend to increase reservoir levels. However, the latter effect is more prominent in dry years, and less prominent in wet years.

FanSi, as configured in this project, exhibits a more aggressive reservoir operation than what has been historically observed. The lowest reservoir fillings we observe, around 1% for Norway as a whole, contrasts with the historical statistics, where the lowest aggregate reservoir fill for any given week over the past two decades is 18% (NVE 2023b).

In Section 6.2, we acknowledged that these low reservoir levels are unrealistic and explained our decision to exclude a specific period from the calculations of average prices. However, it is important to recognize that this caveat could to some degree extend beyond average price calculations to various parts of the results. While FanSi's technical accuracy (employing formal mathematical optimization) provides valuable insights, it is worthwhile to bear in mind that the extreme reservoir operation can potentially influence various parts of the results. The model runs using EMPS offers an alternative set of results based on reservoir operation strategies more in line with current practice. (See also Section 6.3.1 and related discussion in Section 7.6.)

7.4 Socioeconomic surplus

Our analysis also gives results for socioeconomic surplus for producers and consumers. The results illustrate that environmental restrictions mainly affect the income of hydropower producers negatively through reductions in hydropower production and positively through changes in electricity prices. The former effect comes out as most important, leading to a net negative change in income for hydropower producers in general.

Meanwhile, these overarching trends for all hydropower producers obscure variations at the individual power plant level. For example, while the bulk of the reductions in hydropower production will come from power plants subject to new bypass requirements, the number of these power plants is an order of magnitude lower than the number of plants that are not assigned new requirements. Further, reservoirs facing new restrictions will experience reduced flexibility, while many power plants not adversely affected by new bypass or reservoir restrictions will benefit from higher power prices. The results also indicate income gains for non-hydropower producers, primarily wind and solar producers, due to increased power prices. Overall, these points illustrate that the restrictions affect the income of power producers differently, with some producers that are worse off and others better off.

Consumer surplus decreases with the introduction of new environmental restrictions, according to the results. This is a logical outcome given the increase in average power prices.

7.5 Flexibility

When we refer to 'flexibility,' we mean the power system's ability to balance production and consumption. Here, we discuss this topic based on the strengths of the modeling tools we have used, namely FanSi, Primod and EMPS. We do not attempt to provide an exhaustive discussion of the complex subject of flexibility.

In principle, reservoir restrictions limit the freedom of hydropower producers in terms of production timing and quantity. Minimum bypass flow requirements result in production losses that need to be offset by other increases in production (or reductions in consumption), with *a priori* unknown effects on flexibility. The loss of flexibility due to new environmental restrictions will lead to a greater need to utilize other sources of flexibility in the system. In the simulations, we identify three key mechanisms by which the models compensate for the loss of flexibility: Redistributions of water within watercourses, adjustments in various sources of power production, and redistributions of electricity through the power grid. In a few incidents in the simulations, the new environmental restrictions cause significant high prices or exacerbates already high prices after reservoir restrictions become activated and bypass requirements increase in week 18, as we have discussed previously. This may be taken as a sign of reduced flexibility.

In the EMPS simulations, the highest prices increase, and lowest prices decrease. This would be a generally undesirable outcome in the real world, and we interpret it as an indication of reduced flexibility due to new restrictions in these simulations. The fact that FanSi results show this trend less clearly than EMPS, is likely due to FanSi's formal optimization and higher degree of idealization.

The Primod analyses were used to study the availability of spinning reserve capacity. As the number of hydropower plants allowed to contribute with reserve capacity in each simulated week is based on the initial reservoir levels and minimum reservoir requirements, we see the largest impact of implementing new environmental constraints around the snow melting period and week 18. Prior to week 18, new environmental constraints often result in higher reservoir levels and more power plants able to contribute with spinning reserve capacity. The consequence is increased availability of reserve capacity, especially upward. From week 18 on the other hand, new minimum reservoir constraints are imposed, and the number of reserve capacity providers is largely reduced. This also leads to lower availability of both upward and downward spinning reserve capacity in this period. However, as the reservoir levels from the FanSi simulations often are unrealistically low, we believe that the number of reserve capacity providers are unnaturally low in this period. It is important to note here, that FanSi does not consider reserve capacity and the number of reserve capacity providers in its strategy calculation. The low reservoir levels will also lead to an excessively low availability of reserve capacity in these periods. Excluding these periods, we can generally conclude that the average availability of reserve capacity in Norway is sufficient for most of the analyzed weeks, with correspondingly low prices for reserving this capacity. However, if we look at specific time periods within some weeks, we find examples of periods with low availability of both upward and downward reserve capacity in Norway. Periods with low availability of upward reserve capacity are typically when hydropower production and export is high (relatively high-power prices). We find that new environmental constraints can both improve and worsen this situation slightly, depending on the time of the year. Periods with low availability of downward capacity are typically when hydropower production is low, and imports are high (low power prices). We find these periods during summer and autumn, and new environmental constraints tend to increase the availability of downward spinning reserve capacity as the production level is higher. During all these periods it is less costly to dispatch the system if Norway import reserve capacity from neighboring countries. Due to this possibility, the demand for reserve capacity is always covered in the model. It is however important to remember that our analysis is based on a 2030 scenario of the power system, with a total spinning reserve requirement of 2400 MW for the Nordic region. If all plans to increase renewable unregulated power production (e.g., offshore wind) are realized beyond 2030, reserve requirements must probably also increase, particularly for upward regulation. Our analysis can indicate that environmental constraints can increase the availability of upward spinning reserve capacity in strained periods, but this will depend on the selection criterions for reserve capacity providers which are simplified in our model (and more complex in reality).

New environmental constraints generally lead to increased availability of upward spinning reserve capacity prior to week 18, and lower availability from week 18 and a few weeks ahead. This is largely correlated to the number of power plants able to provide this capacity in the model. However, we find some re-distributional effects of new environmental constraints on what power plants contribute with upward reserve capacity. Power plants subject to minimum production requirements naturally provide more upward spinning reserve capacity when the constraints are imposed, while power plants subject to bypass requirements provides less upward reserve capacity in many weeks due to a combination of lower production and fewer power plants qualified for providing this capacity. Even tough new environmental constraints generally lead to lower levels of downward spinning reserve capacity as the total production is reduced (due to minimum bypass requirements), we also find that new environmental constraints can lead to increased levels of downward reserve capacity in some periods. This effect is most prominent for power plants subject to minimum reservoir levels in late summer/autumn due to increased production.

Even though we have employed the most suitable models available, the analyses may underestimate the challenges related to flexibility. The analyses were conducted at a three-hour time resolution, thus not allowing for our assessing flexibility aspects on shorter time scales. Also, a general point to note is that the models tend to underestimate variations observed in real-world power prices. Finally, it is worthwhile keeping in mind that we have analyzed the power system for the year 2030, the needs for flexibility in the system can potentially increase significantly with more extensive variable wind and solar power production in the 2035-2040 timeframe. For these reasons, we refrain from drawing firm conclusions about the significance of new environmental restrictions for the power system.

7.6 Experiences from power system modelling

The prototype models FanSi and Primod have been the main power system models used for analyses in the present project, SumEffekt. Both models are currently in relatively early development stages (compared for example to well-established EMPS). FanSi and Primod have been used to analyze a variety of scenarios or cases and have been proven to produce consistent and reliable results. Meanwhile, we have gathered valuable insights that contribute to the ongoing development and use of the models, including insights into present shortcomings of the models. In the following, we summarize the key experiences from SumEffekt contributing to the further development of the models.

FanSi, as configured in this project, gives a more aggressive reservoir operation strategy than what has been historically observed (Section 6.3.1). The low FanSi reservoir fillings can be explained by FanSi relying on formal mathematical optimization without user input or subjective risk assessment. With this approach and the current model configuration, FanSi takes a risk-neutral approach where all years are treated with equal probability and there is no direct or indirect consideration to more extreme events than described by the input.

EMPS, in contrast, incorporates user input and heuristics to give reservoir operation strategies that are more in line with observed reservoir operation strategies. These strategies may include risk aversion and considerations to unmodelled events like component failures or more extreme inflows. Against this background, we see a need for further advancing FanSi by incorporating features that allow the users to be able to influence FanSi's reservoir operation strategies. There exists some more or less untested functionality for this in FanSi that has not been utilized in this project. Future research related to this subject is recommended.

We have also observed that the reservoir operation in FanSi can be significantly influenced by the end water values from EMPS. Contrary to the initial expectation that the end values obtained from EMPS will have limited influence on the final results from FanSi, this observation shows that a consistent set of water values from EMPS can be crucial when comparing results from different FanSi simulations with smaller input differences. Using a longer planning horizon in FanSi reduces this problem at the cost of increased computation time.

As a final comment regarding FanSi, we have observed that results for individual modules in extreme situations can be sensitive to the number of scenarios in the scenario fan. Generally, a higher number yields better results but demands more computational resources.

The Primod model was used to see if higher time resolution, spinning reserve requirements, and a more detailed modelling of thermal power plants and partly hydropower plants give additional insight into the flexibility of the modelled system, especially focusing on reserve capacity. It is however important to remember that the power of the short-term model is also not fully utilized in this project, as the time resolution of input data is coarser than the model can handle (1-hour/3-hour vs. 15 minutes).

Primod was used to analyze close to 200 weeks, and a comprehensive comparison with the FanSi-results show a large degree of consistency. The differences in results can be explained by technical differences in the modelling, where the interpolation in water values/cuts, the solution of daily problems (weekly problems in FanSi), and a daily resolution for inflow in Primod (weekly resolution in FanSi) are the most important factors. In addition, reserve requirements (when binding) will also affect the dispatch in Primod. Lastly, if an initial reservoir level from FanSi is below a hard minimum reservoir constraint, Primod will implement this result as an error and set the initial reservoir level equal to the constraint. This might lead to different hydropower production from the two models. As a final comment regarding Primod, it is important to remember that the model results will be largely coloured by the results that FanSi produces, as both initial reservoir levels and the strategy for hydropower operation is based on the FanSi-results. Thus, the same considerations regarding reservoir operation should be kept in mind.

7.7 Final remarks

We here summarize the main findings from the project and note major uncertainties and limitations.

We estimate that Norway's hydropower production will decrease by 3 TWh yr^{-1} on average due to new environmental restrictions. While this is a relatively modest reduction of 2% in the total hydropower production, it concerns electricity that is particularly valuable because of its flexibility. In the real world, replacing 3 TWh yr^{-1} of flexible electricity would not be straightforward. Thus, the results illustrate an important trade-off between enhancing environmental protection of regulated watercourses on the one hand and maximizing valuable flexible power generation on the other hand. The estimate of 3 TWh yr^{-1} is consistent across a range of scenario assumptions for the power system in 2030, but there is uncertainty, particularly regarding our assumptions about the quantity and strictness of new minimum bypass requirements. These assumptions might differ from actual requirements as defined in real licenses.

The project has developed a method for estimating environmental flows in bypass reaches, given that we can assume the locations of the requirements and need to estimate their magnitude. The method is an advancement over previous assessments that strictly use Q95 to represent minimum bypass requirements. It builds on natural flow represented by Q95, but it also incorporates site-specific adjustments to differentiate requirements depending on expected environmental impact and power loss. It further incorporates seasonality in the requirements. When compared to available information on actual requirements, our estimates appear more realistic than non-adjusted Q95, which tends to overestimate requirements in general.

We estimate that power prices increase 1-2% on average. This is primarily due to minimum bypass flow requirements, possibly with additional contributions from reservoir restrictions. The simulations identify certain incidents with relatively large price increases in connection to intensification of restrictions that are assumed to take place in week 18. This suggests that environmental restrictions have the potential to trigger high prices or amplify high prices during challenging periods. The real-world significance of this type of impact is still difficult to ascertain, however. What is clear is that some incidents with relatively large price increases occur in the simulations, but they occur quite rarely. Meanwhile, it is reasonable to assume that the power system models to some degree underestimate such events. Because the time resolution of the FanSi and EMPS modelling was 3 hours, these analyses do not address potential consequences on shorter timescales.

In general alignment with the purpose of reservoir restrictions, reservoirs facing new restrictions experience more water accumulation and more rapid water level rises in the spring. Simultaneously, there is a tendency for reservoir levels to decrease for reservoirs not facing new restrictions. In total across whole model areas, results show small changes in aggregated reservoir operation, indicating that the new environmental restrictions will not have a major impact on simulated aggregate storage. Reservoir restrictions increase aggregate reservoir levels in dry years, but not necessarily so in wet years.

The loss of flexibility due to new environmental restrictions will lead to a greater need to utilize other sources of flexibility in the system. In the simulations, the loss is to a large extent compensated for by exploiting the flexibility of other reservoirs (not facing new restrictions) and through adjustments in the power import/export between Norway and other countries.

During the project, we have gathered valuable insights that contribute to the ongoing development of the FanSi and Primod models. A particular point to make is that we see a need for further advancing FanSi by incorporating functionality that gives more risk averse reservoir operation. Another useful observation is the importance of the end water values from EMPS used in FanSi.

Our results are subject to significant uncertainties. One source of uncertainty is that the number and stringency of environmental constraints defined in actual licenses may differ significantly from our estimates. Uncertainty also arises from the aggressive reservoir scheduling observed in simulation results from FanSi, which deviates from historical observations and thus may complicate interpretations of results in a real-world setting. The FanSi and EMPS models have somewhat different reservoir operation strategies. This gives differences in how the consequences of the new constraints are distributed over the year and how prices change for the most extreme cases. For these types of results, it is difficult to draw certain conclusions. The analyses were conducted using power system data representing the year 2030, thus not addressing even more extensive variable wind and solar power production in a 2035-2040 timeframe. The flexibility of hydropower can be even more valuable in such an extended timeframe.

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A Supplementary results

A.1 New environmental constraints per model area

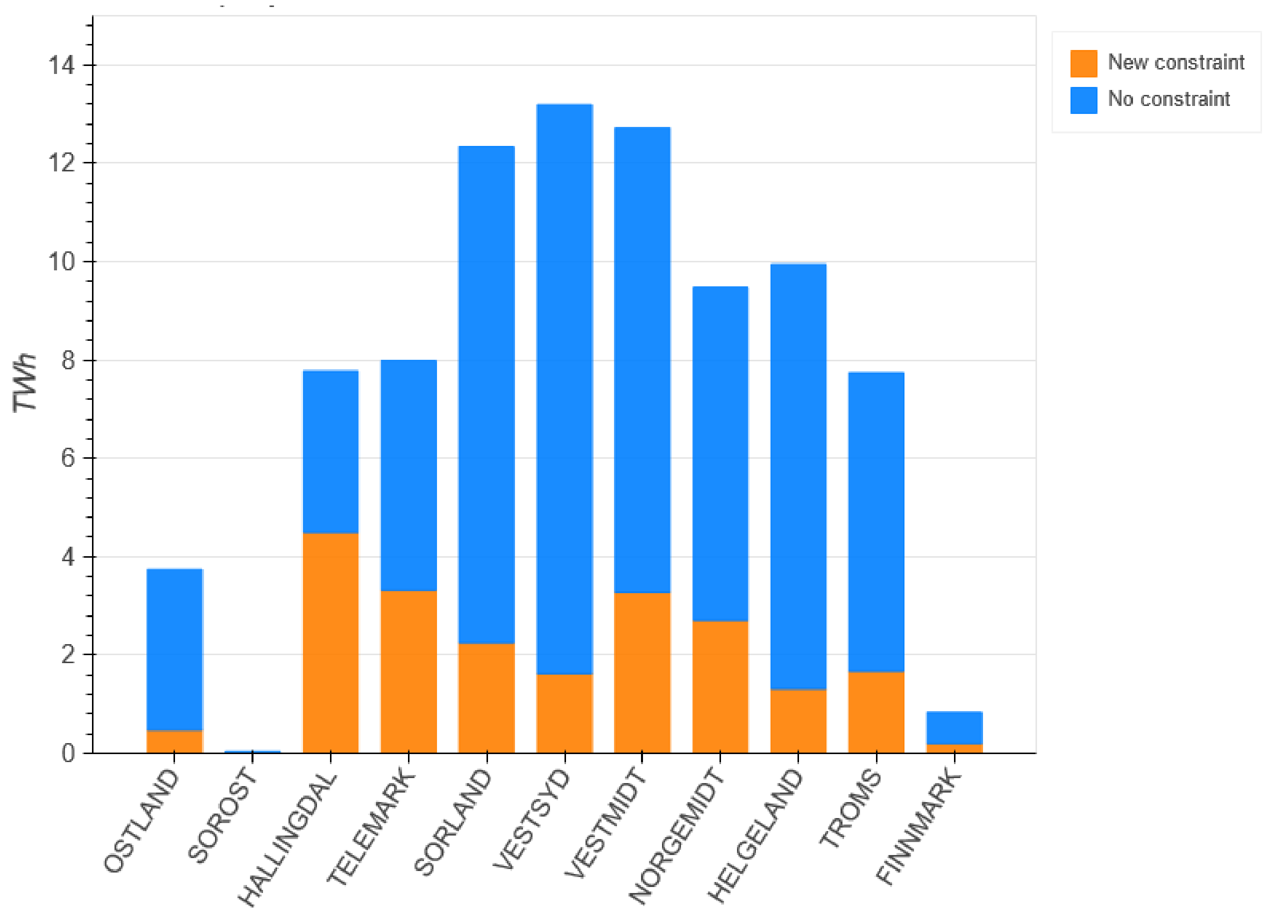

Figure 59 The total reservoir capacity in each model area divided into capacity subject to new constraints and not.

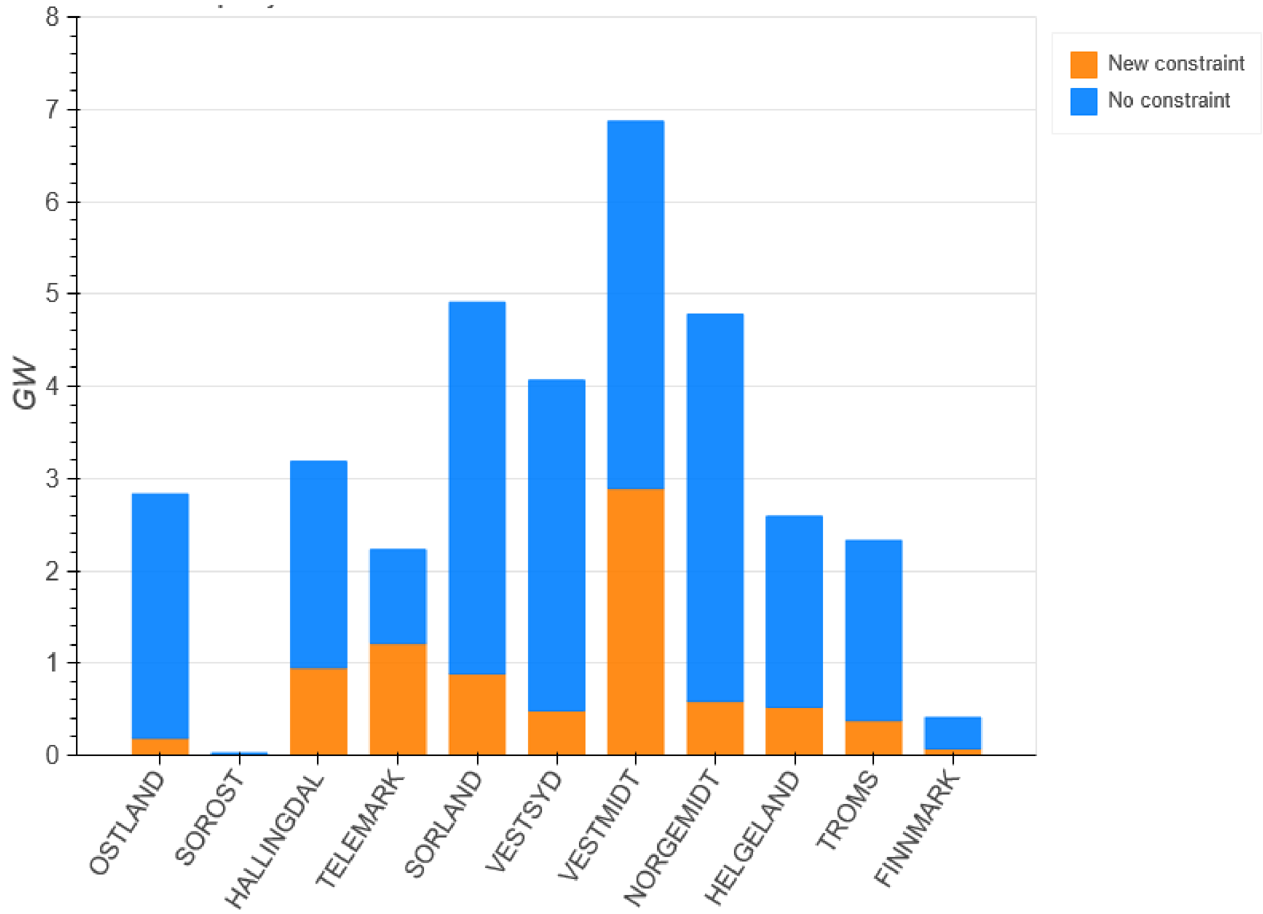

Figure 60 The total production capacity in each model area divided into capacity subject to new reservoir constraints and not.

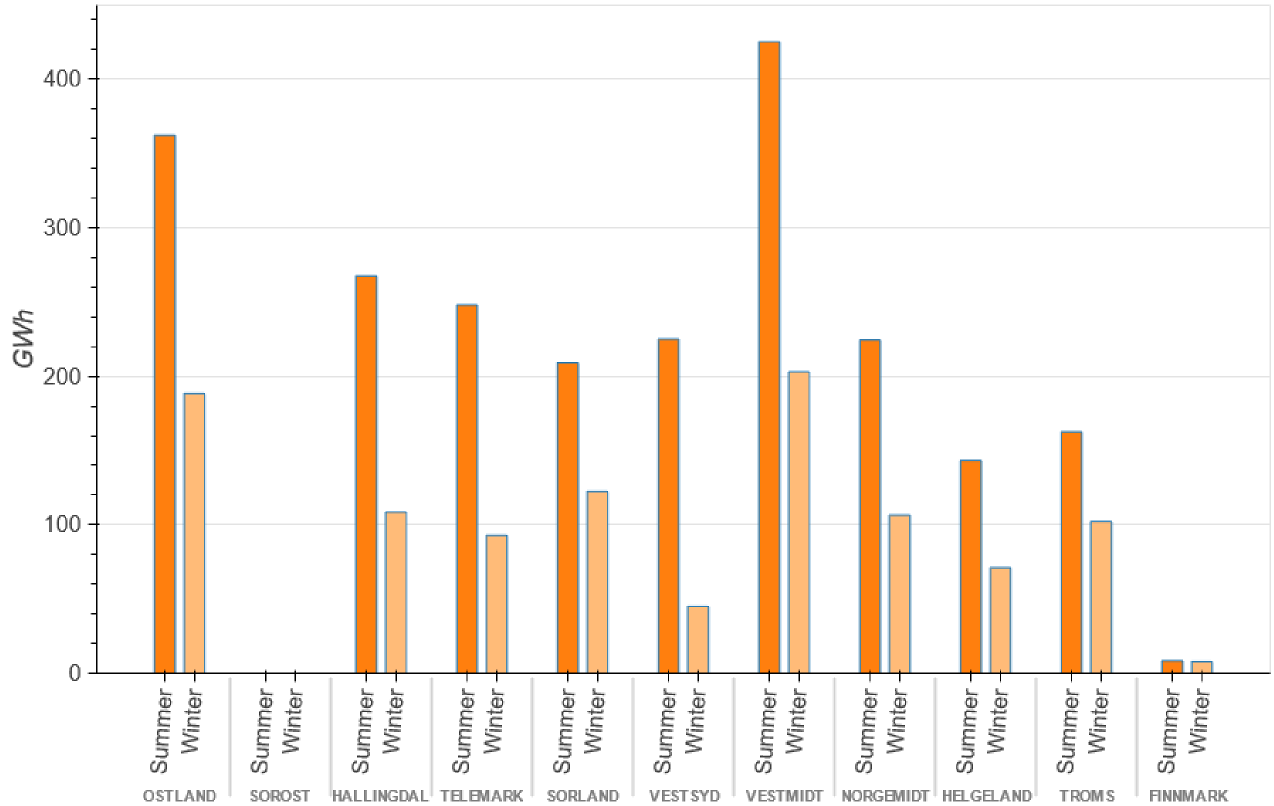

Figure 61 The total theoretical production loss during summer and winter due to the new minimum bypass requirements per price area.

A.2 Hydropower production

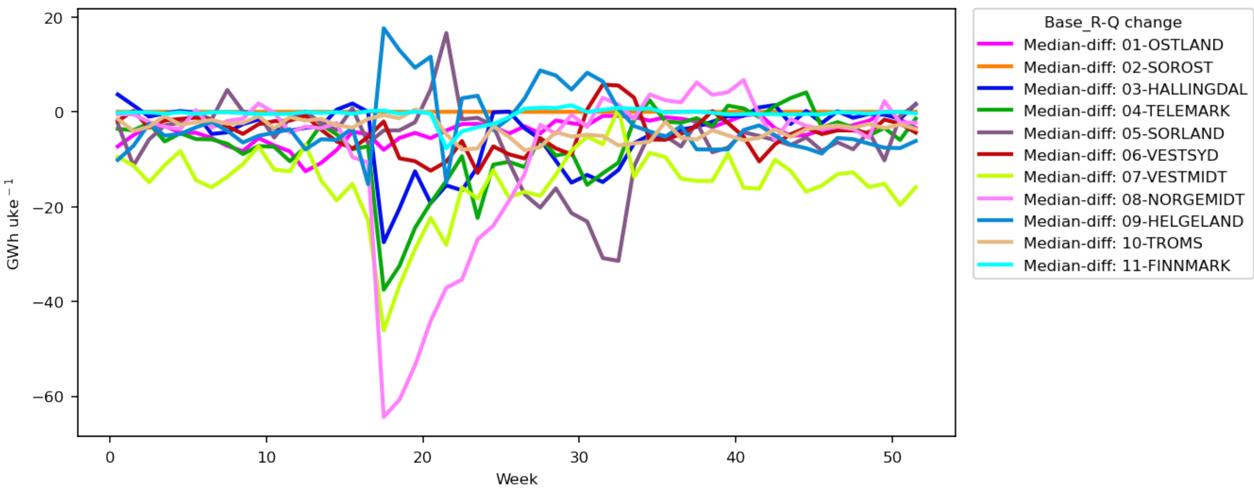

Figure 62 Average weekly change in hydropower production over the year because of the introduction of new environmental restrictions. Results are shown for 11 model areas for scenario Base_R-Q.

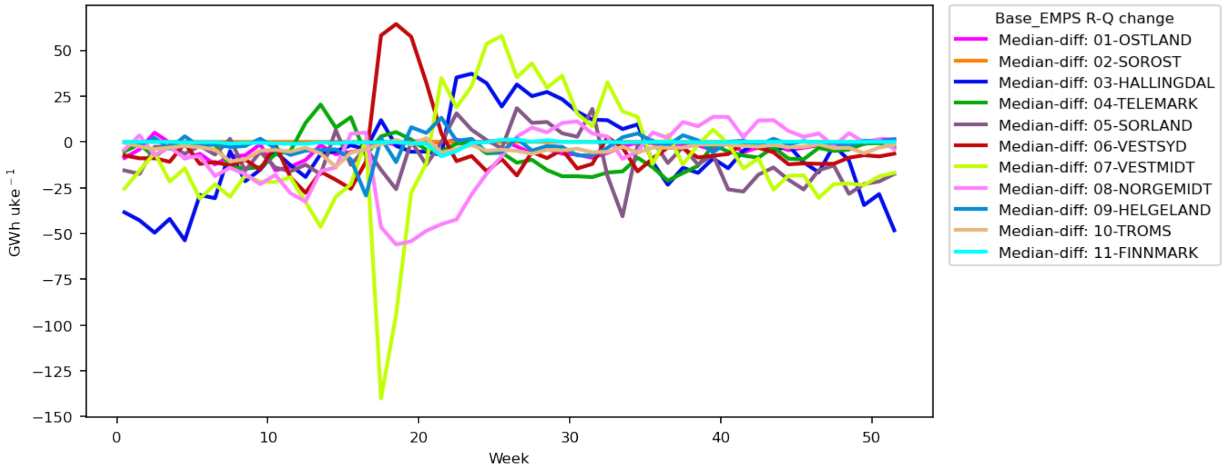

Figure 63 Average weekly change in hydropower production over the year because of the introduction of new environmental restrictions. Results are shown for 11 model areas for scenario Base_EMPS_R-Q.

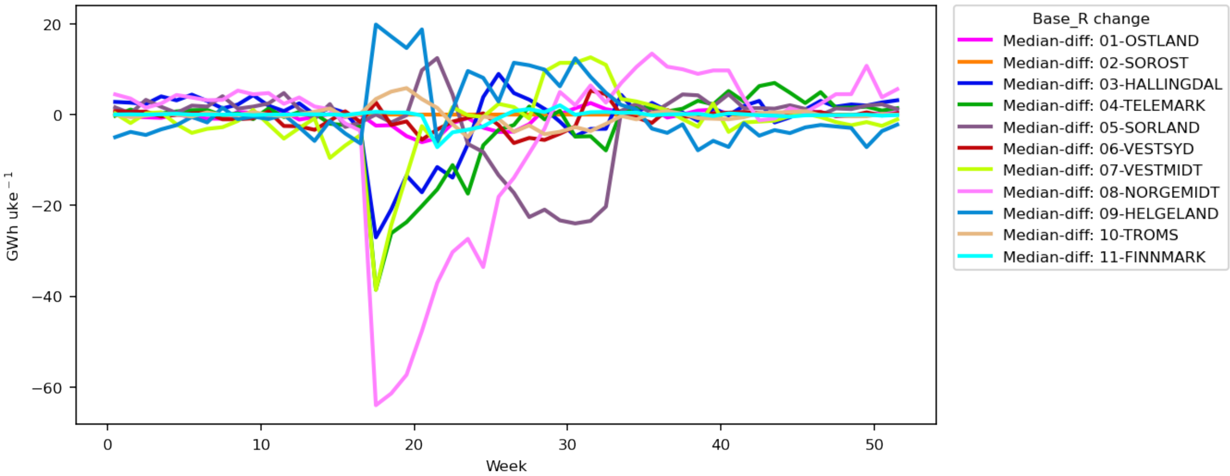

Figure 64 Average weekly change in hydropower production over the year because of the introduction of new environmental restrictions. Results are shown for 11 model areas for scenario Base_R.

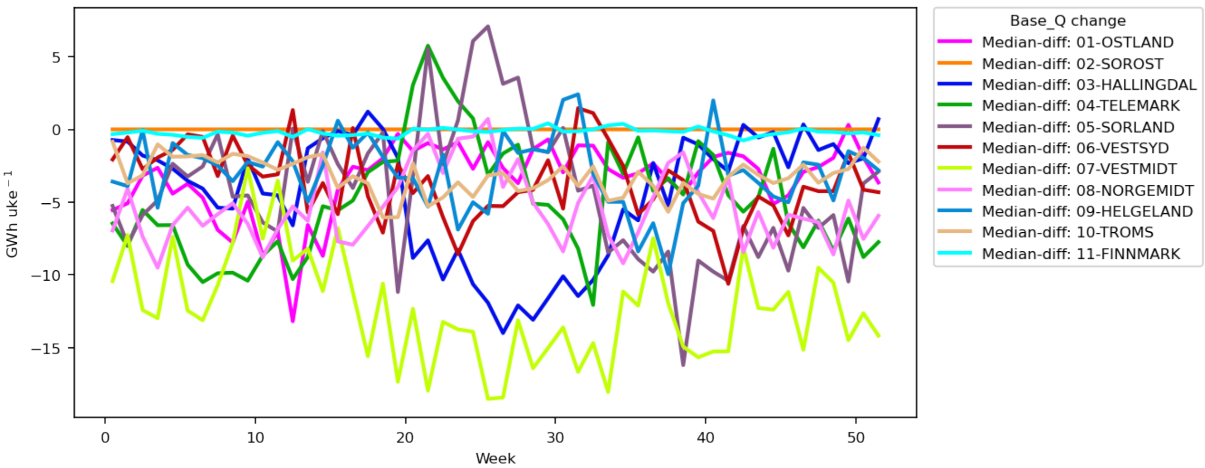

Figure 65 Average weekly change in hydropower production over the year because of the introduction of new environmental restrictions. Results are shown for 11 model areas for scenario Base_Q.

A.3 Power price

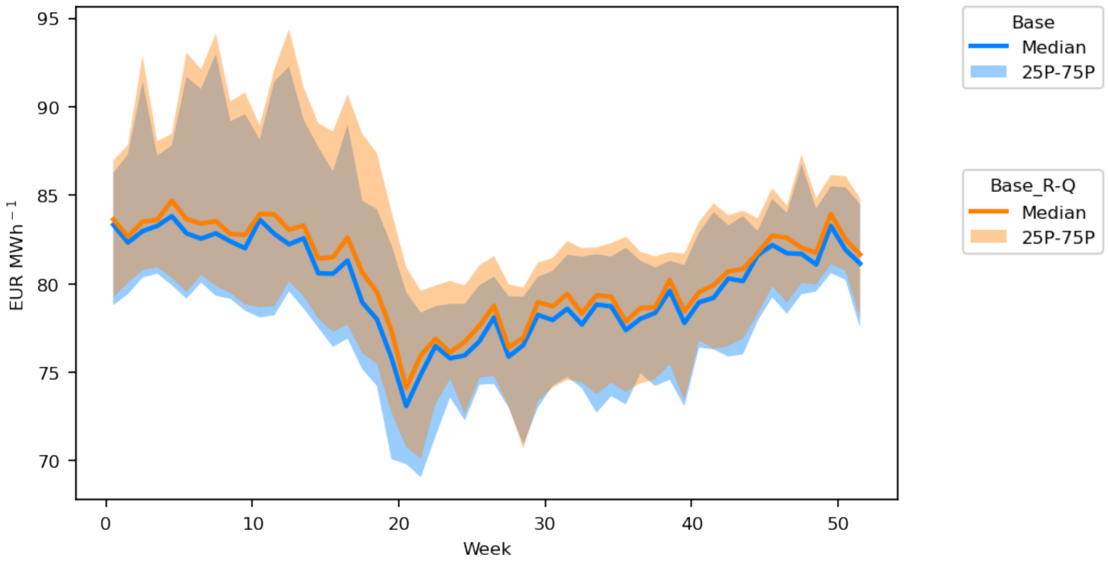

Figure 66 Weekly power price from FanSi model runs without ("Base") and with ("Base_R-Q") new environmental restrictions. Solid lines represent medians and shaded areas interquartile ranges (25-75 percentiles) for 35 simulated weather years.

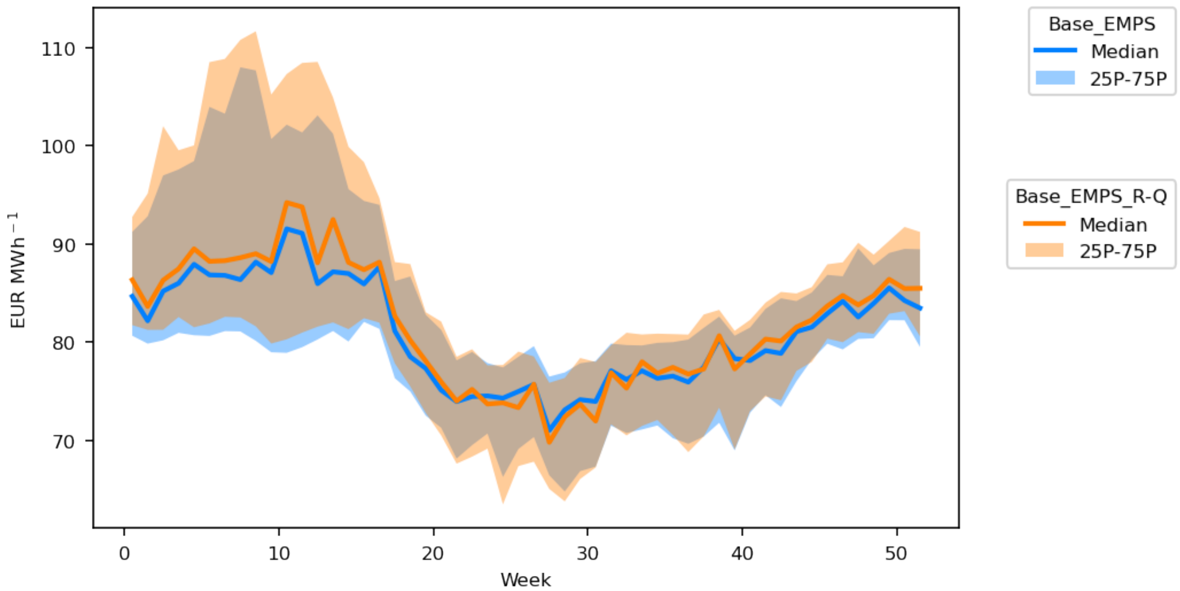

Figure 67 Weekly power price from EMPS model runs without ("Base_EMPS") and with ("Base_EMPS_R-Q") new environmental restrictions. Solid lines represent medians and shaded areas interquartile ranges (25-75 percentiles) for 35 simulated weather years.

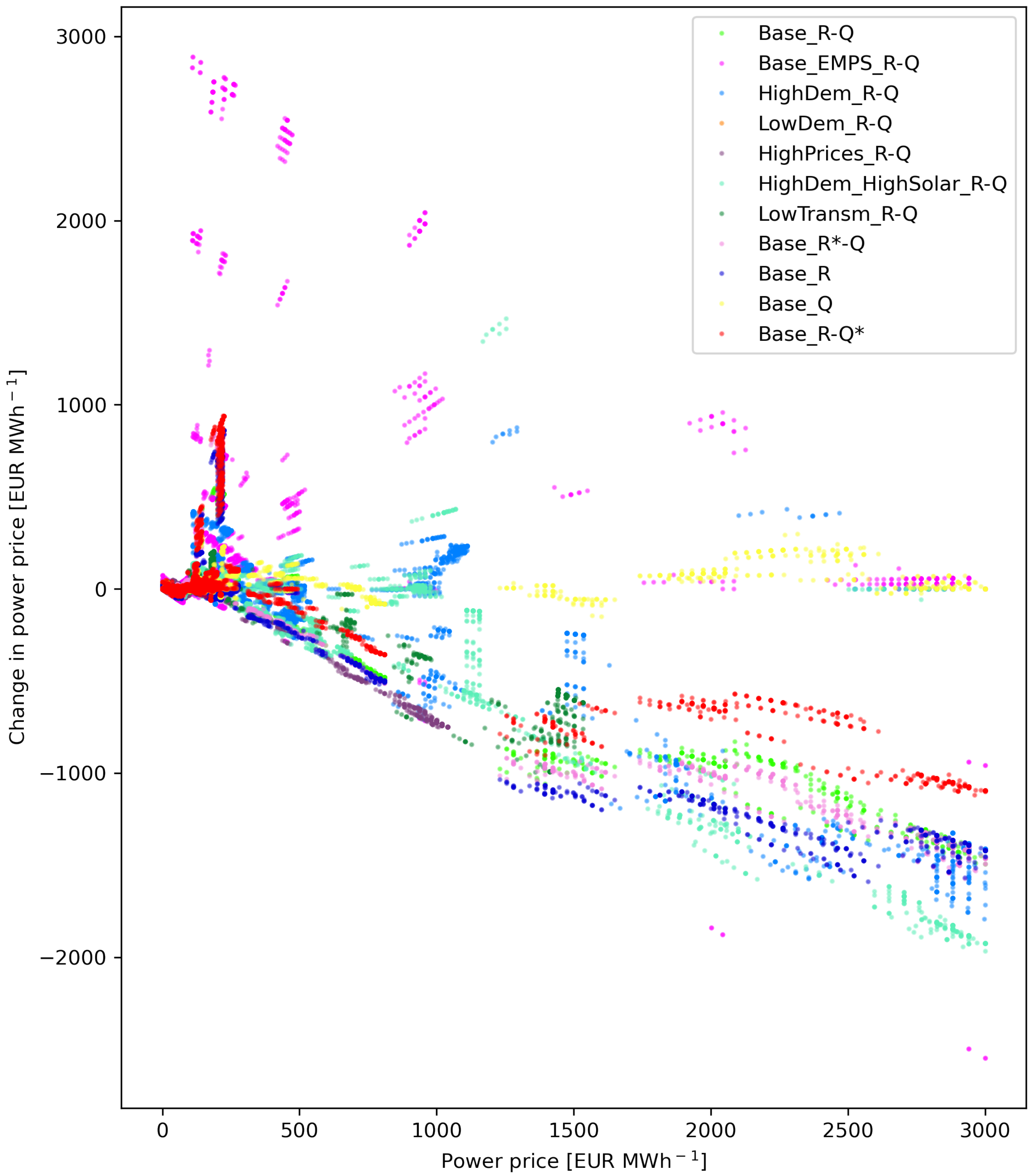

Figure 68 Change in power price as a result of the environmental restrictions (vertical axis) versus the power price without the restrictions (horizontal axis) broken down by eleven scenario pairs (e.g., Base and Base-R-Q). As is explained in the main text, there are 12.3 million data points. However, note that very many data points overlap with each other in a densely populated area below around 100 EUR MWh^{-1} on horizontal axis and between around around 0.5 to 2 EUR MWh-1 on the vertical axis. This figure differs from Figure 31 shown previously in that week 15-16 in year 1986 is included in the current figure but excluded in Figure 31 (see also discussion in relation to Figure 31).

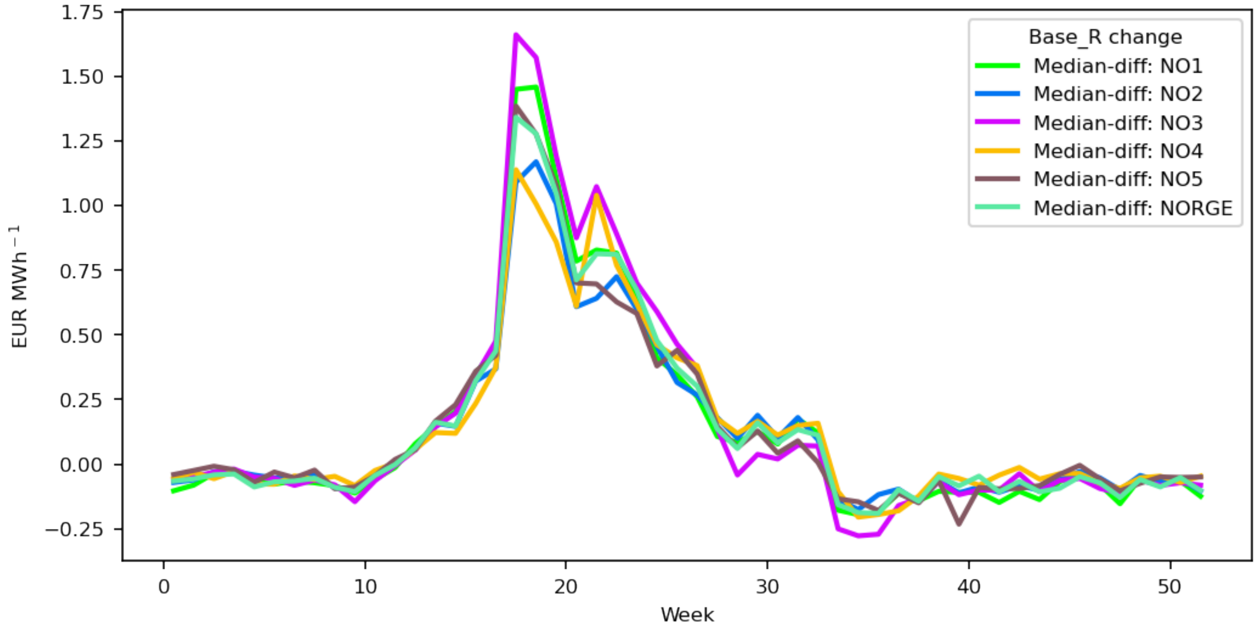

Figure 69 Change in weekly power price with environmental restrictions (R only) over the year with scenario Base and model FanSi. See caption to Figure 32 for further explanation.

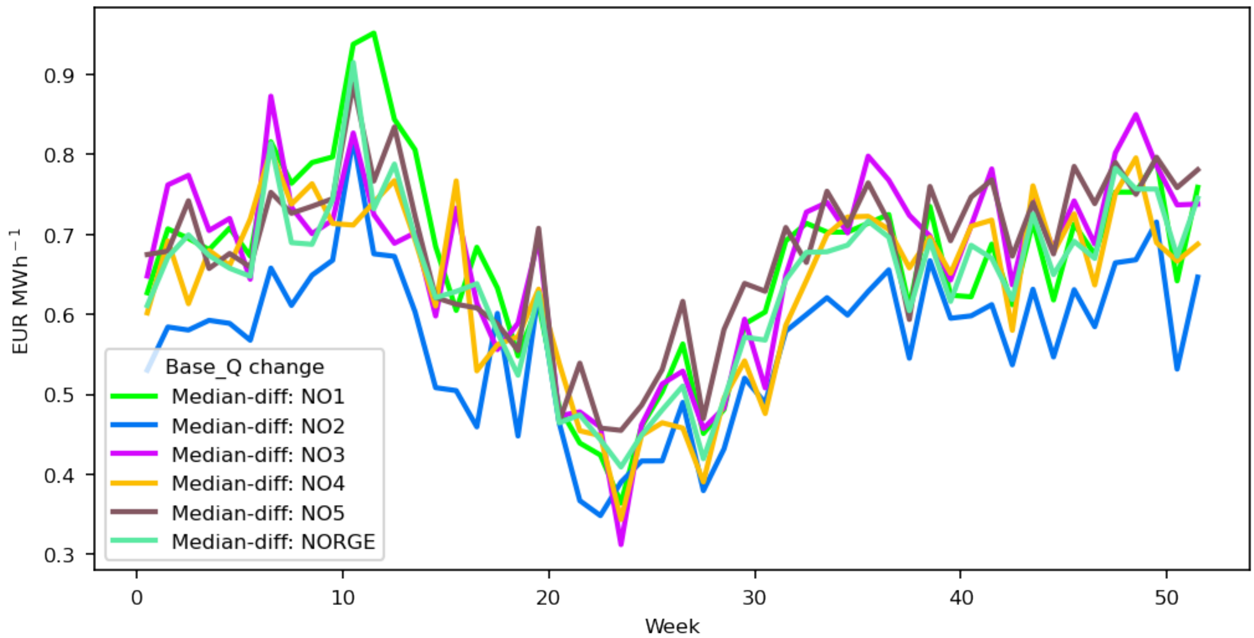

Figure 70 Change in weekly power price with environmental restrictions (Q only) over the year with scenario Base and model FanSi. See caption to Figure 32 for further explanation.

A.4 Reservoir operation

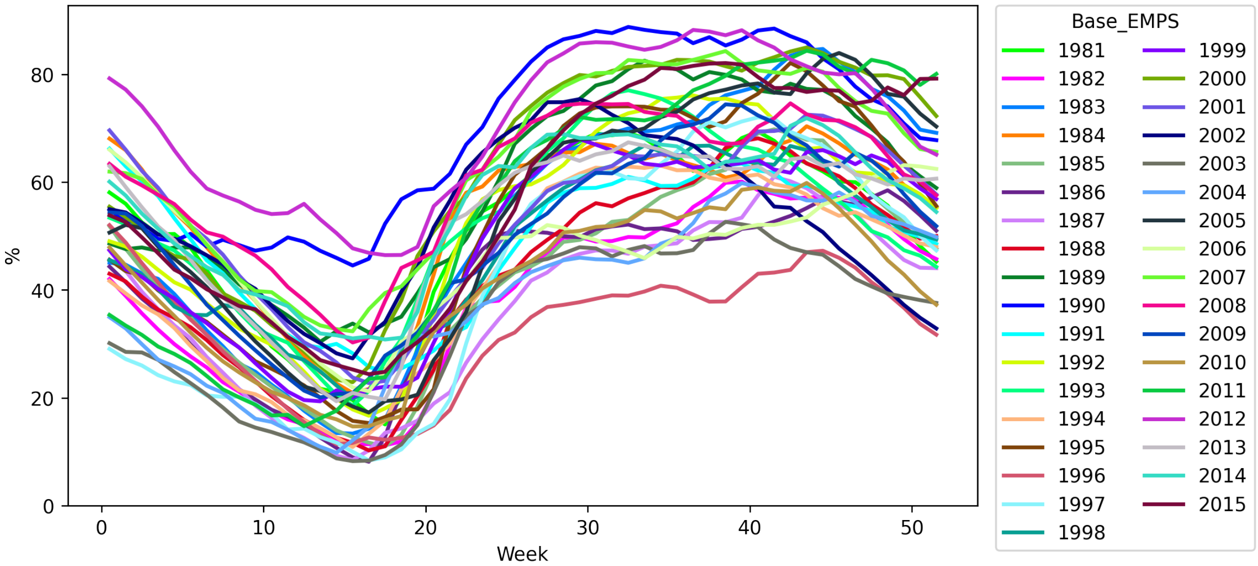

Figure 71 Simulated aggregated reservoir fillings for Norway in scenario Base (using EMPS model) for 35 individual weather years. Results are measured as percentage (%) of maximum reservoir capacity.

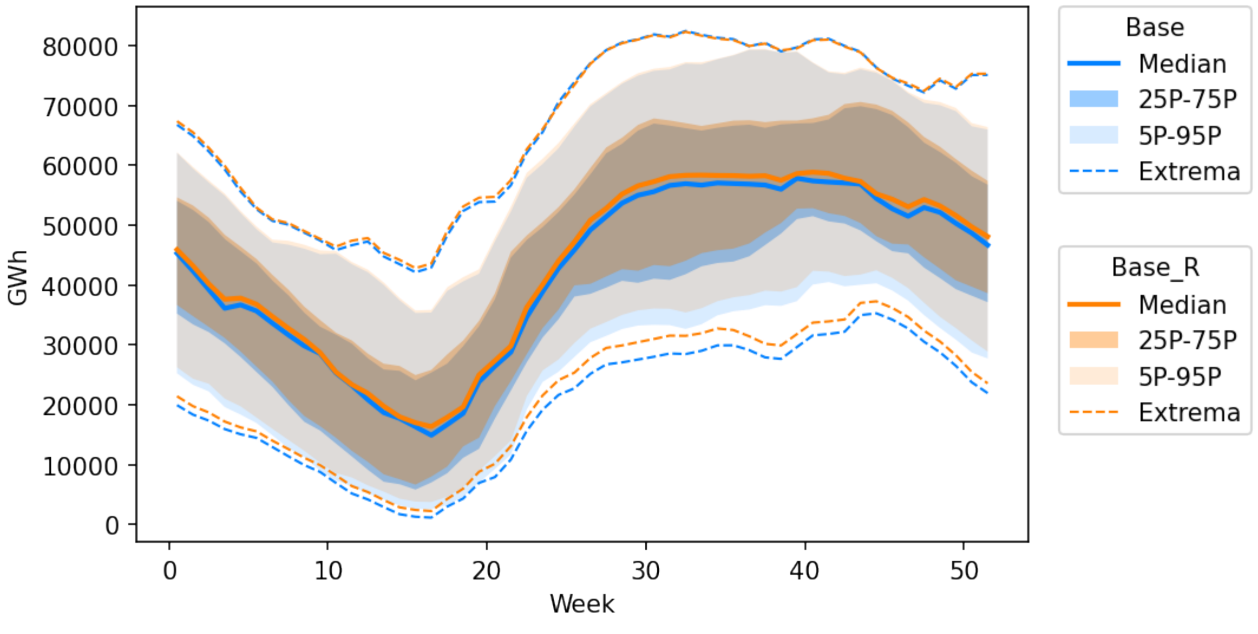

Figure 72 Simulated aggregated reservoir fillings for Norway in scenario Base and Base_R respectively. Results are measured in energy equivalents (GWh). Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

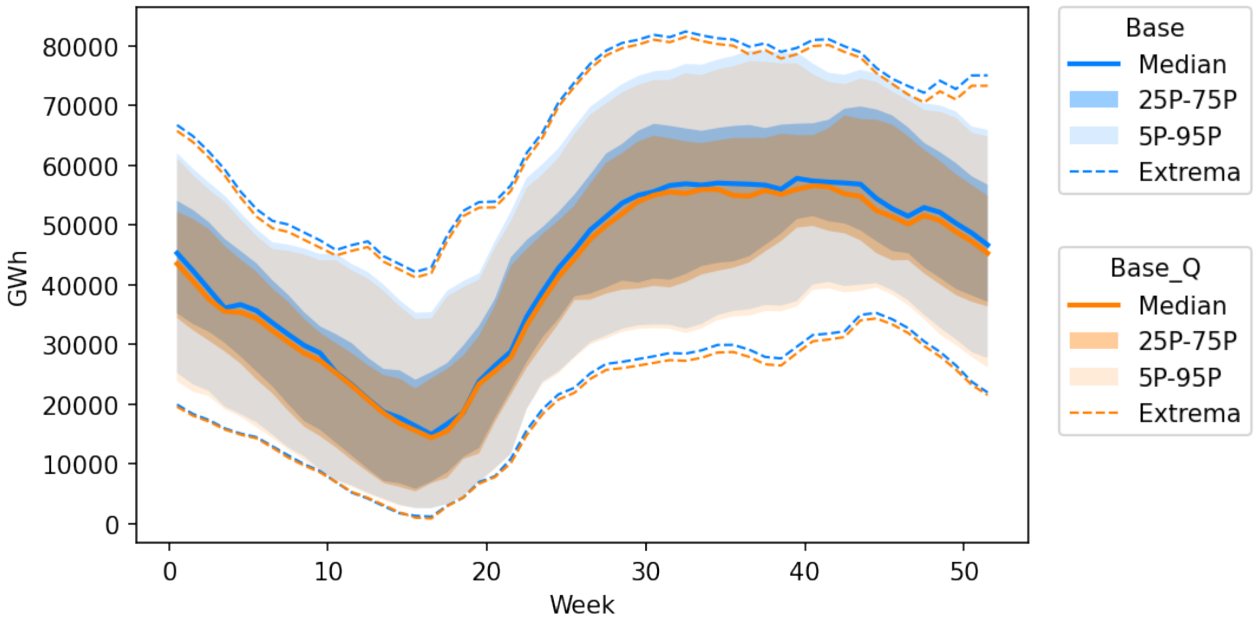

Figure 73 Simulated aggregated reservoir fillings for Norway in scenario Base and Base_Q respectively. Results are measured in energy equivalents (GWh). Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

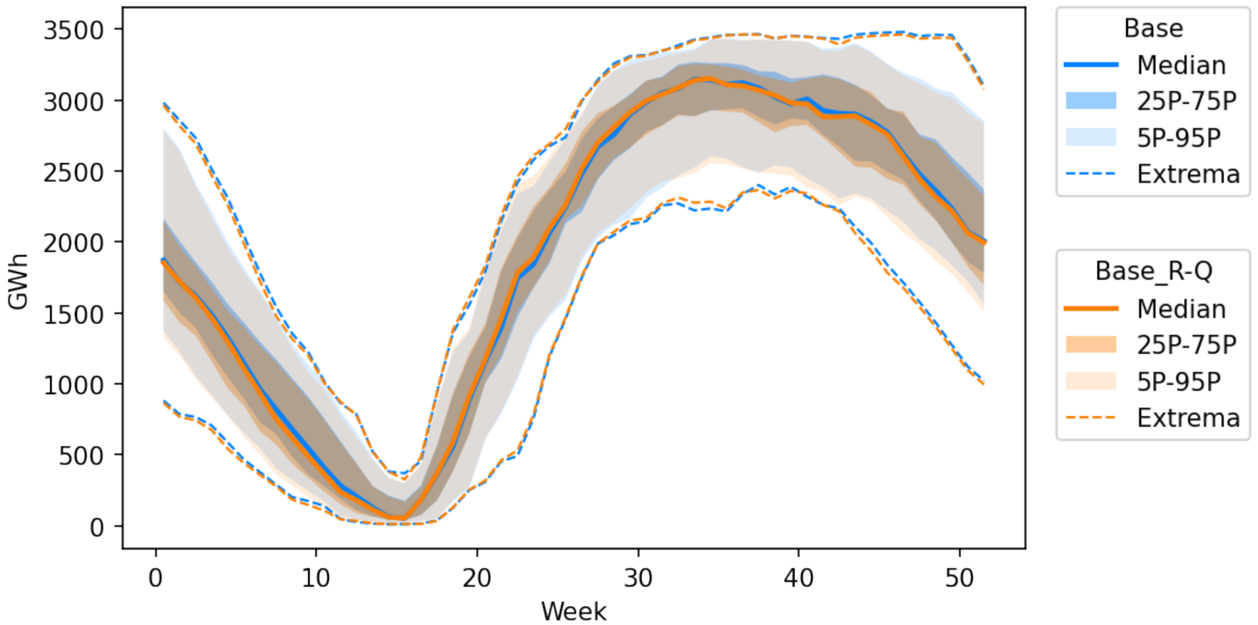

Figure 74 Simulated aggregated reservoir fillings for price area NO1 in scenario Base and Base_R-Q respectively. Results are measured in energy equivalents (GWh). Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

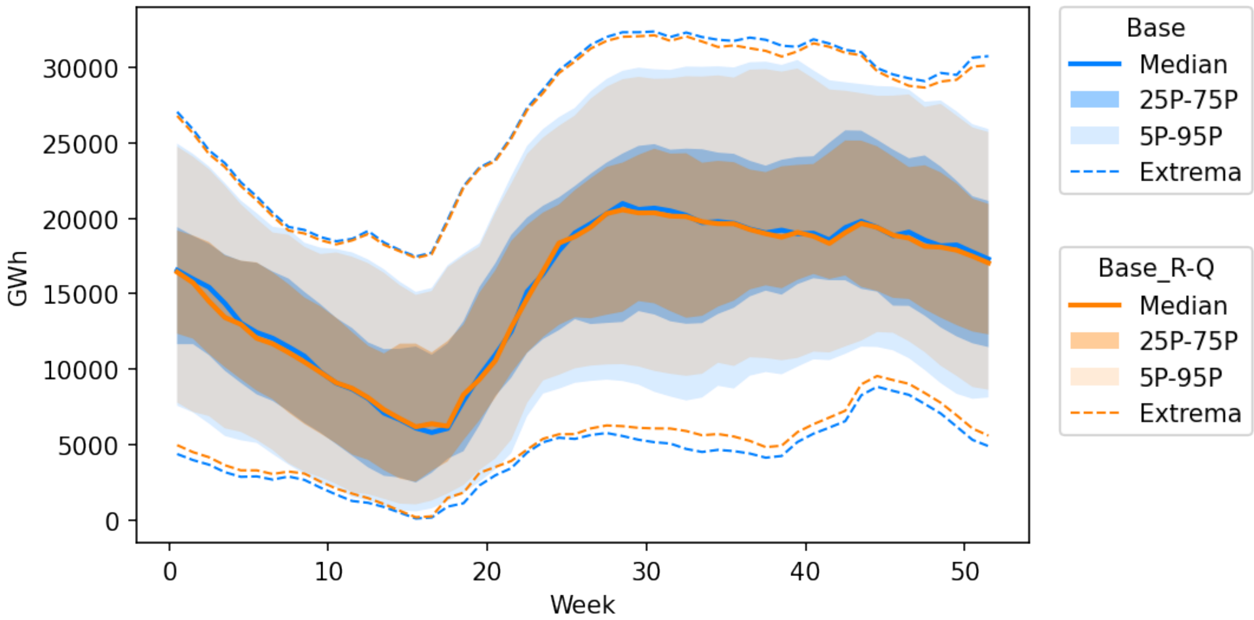

Figure 75 Simulated aggregated reservoir fillings for price area NO2 in scenario Base and Base_R-Q respectively. Results are measured in energy equivalents (GWh). Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

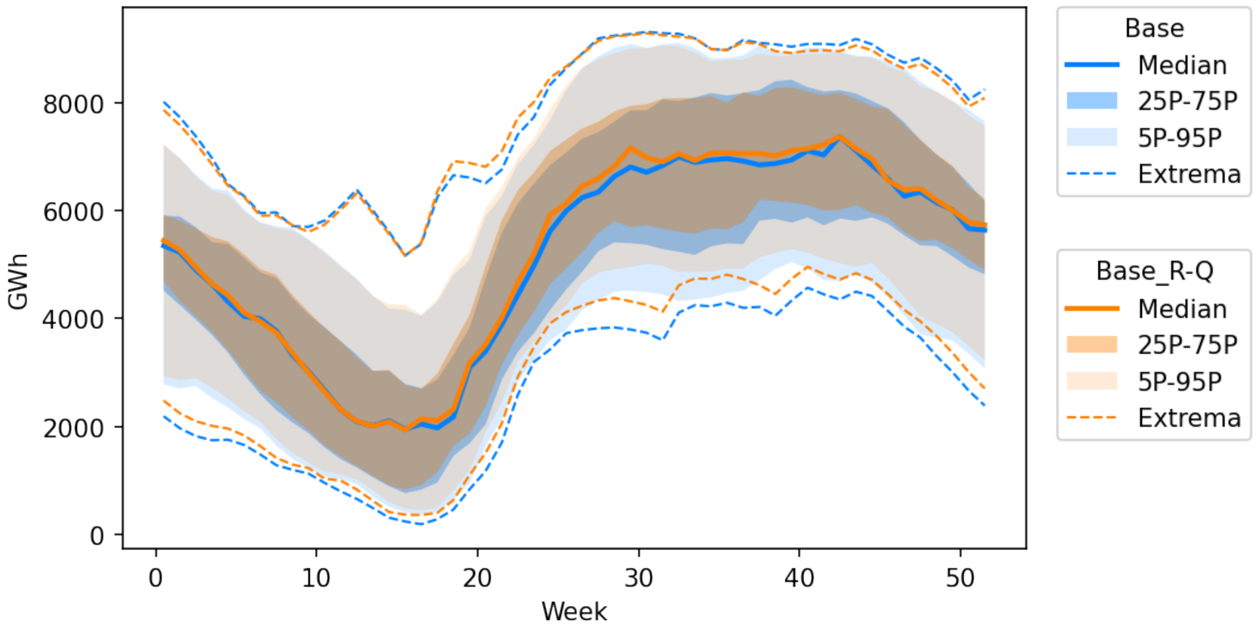

Figure 76 Simulated aggregated reservoir fillings for price area NO3 in scenario Base and Base_R-Q respectively. Results are measured in energy equivalents (GWh). Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

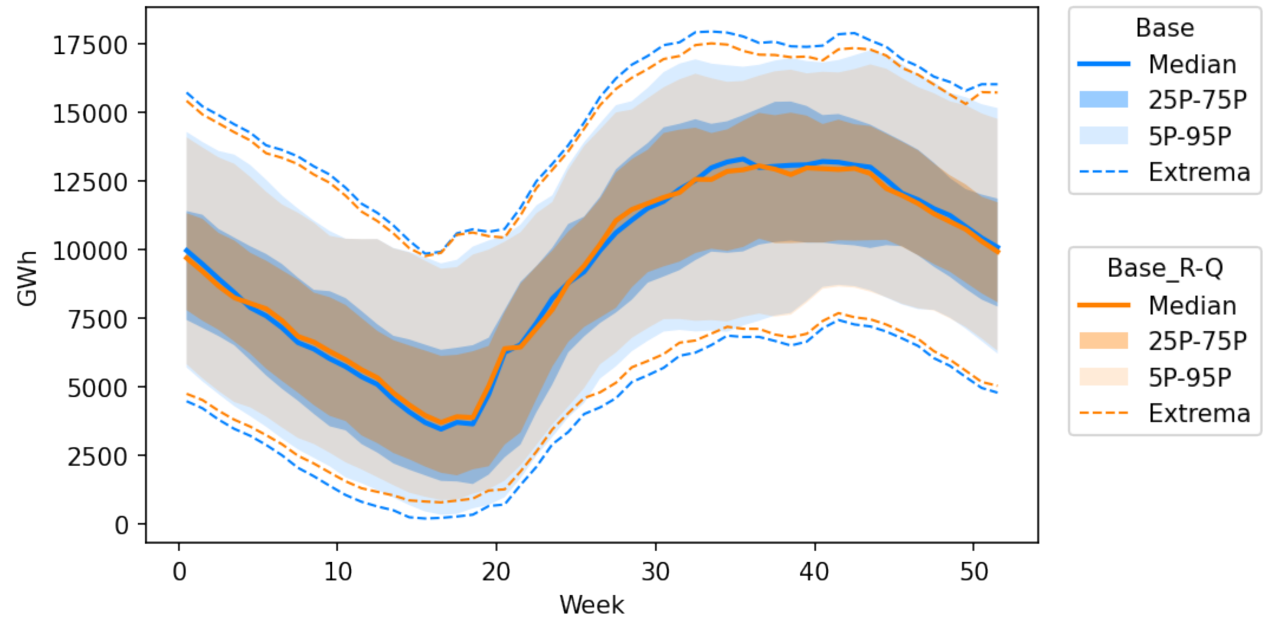

Figure 77 Simulated aggregated reservoir fillings for price area NO4 in scenario Base and Base_R-Q respectively. Results are measured in energy equivalents (GWh). Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.

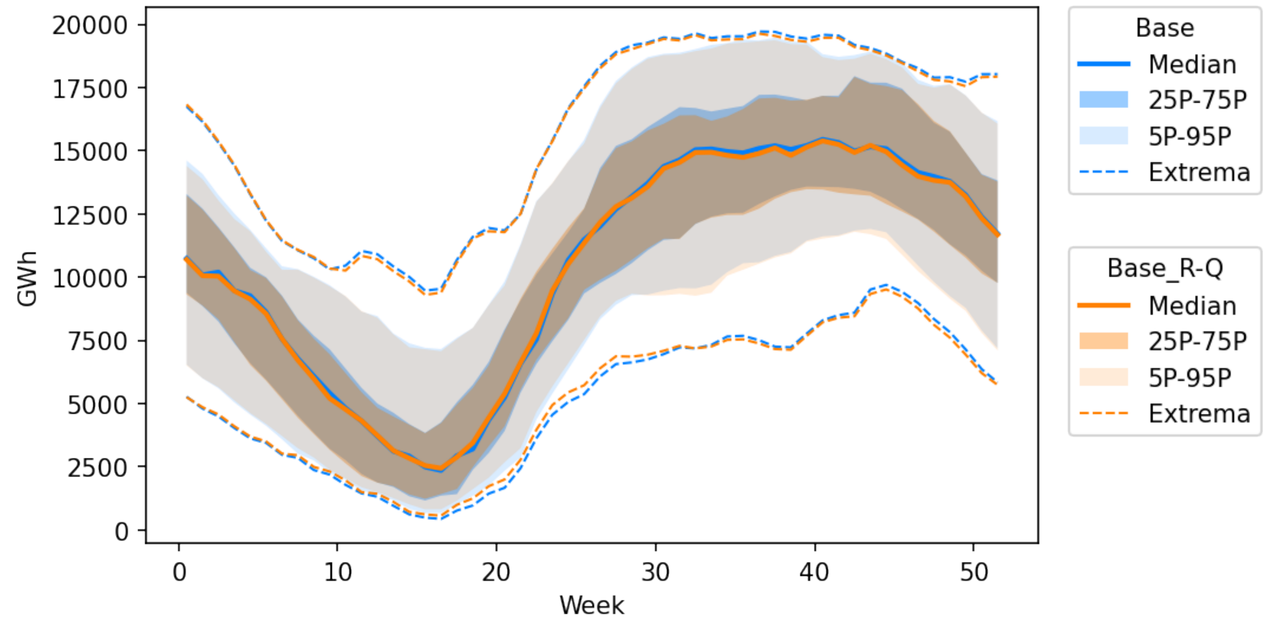

Figure 78 Simulated aggregated reservoir fillings for price area NO5 in scenario Base and Base_R-Q respectively. Results are measured in energy equivalents (GWh). Solid lines represent medians, dark shaded areas 25-75 percentiles, light shaded areas 5-95 percentiles and dashed lines minimum/maximum across 35 simulated weather years.